Fundamentals of Capacity Market Design and Performance

Presented by

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TOPICS

I. Role and Design of Capacity Markets

A. Why Capacity Markets?

WHY ICAP? Overview

Under the traditional vertically integrated utility, resource adequacy standards were resolved between the individual utility and its regulators.

- The consequences of resource inadequacy were straightforward: the utility that lacked sufficient generation to meet its load would need to buy power (potentially at extremely high prices) or to shed firm load during shortage conditions.
- Determining which utility had to shed firm load during a shortage was easy: it was the utility that was short of power.
- Determining which utility could use the transmission system to deliver power during a shortage was also easy; those who had paid for firm service had priority.

WHY ICAP? Overview

The introduction of power pools and economic dispatch required changes in this resource adequacy system because there was no longer a clear link between generation and load.

- A utility might be a net buyer during a shortage, not because it was short of capacity but because its capacity was providing reserves or had been redispatched to manage congestion.
- Moreover, within a power pool, transmission usage was determined by economic dispatch, not by firm transmission rights.
- Within a power pool, the assignment of load shedding responsibility could no longer be based on generation ownership or firm transmission rights but was shared across load serving entities within the capacity short region.

WHY ICAP? Overview

Shared responsibility for load shedding leads to incentive problems because it is very expensive on a per megawatt basis to maintain marginal capacity sufficient to meet load on a one-day-in-ten-year reliability criteria. The marginal capacity is hardly ever used but needs to be paid for by customers.

- With the introduction of power pools there was a potential incentive for utilities to “lean on the pool,” by reducing the amount of capacity they maintained, then buying power based on a split savings price during shortage situations. This behavior would increase the probability of load shedding to a higher level than would be socially optimal;

WHY ICAP? Overview

- Because the split savings price paid for purchasing power from the power pool would not reflect the cost of load shedding, part of the reliability impact of inadequate generating capacity would fall on other members of the pool.

- These incentive problems led to the development of installed reserve requirements in the Northeast power pools as well as in some Midwestern reserve sharing programs. These reserve requirement designs required that all pool members provide their share of the capacity needed to maintain pool reliability.

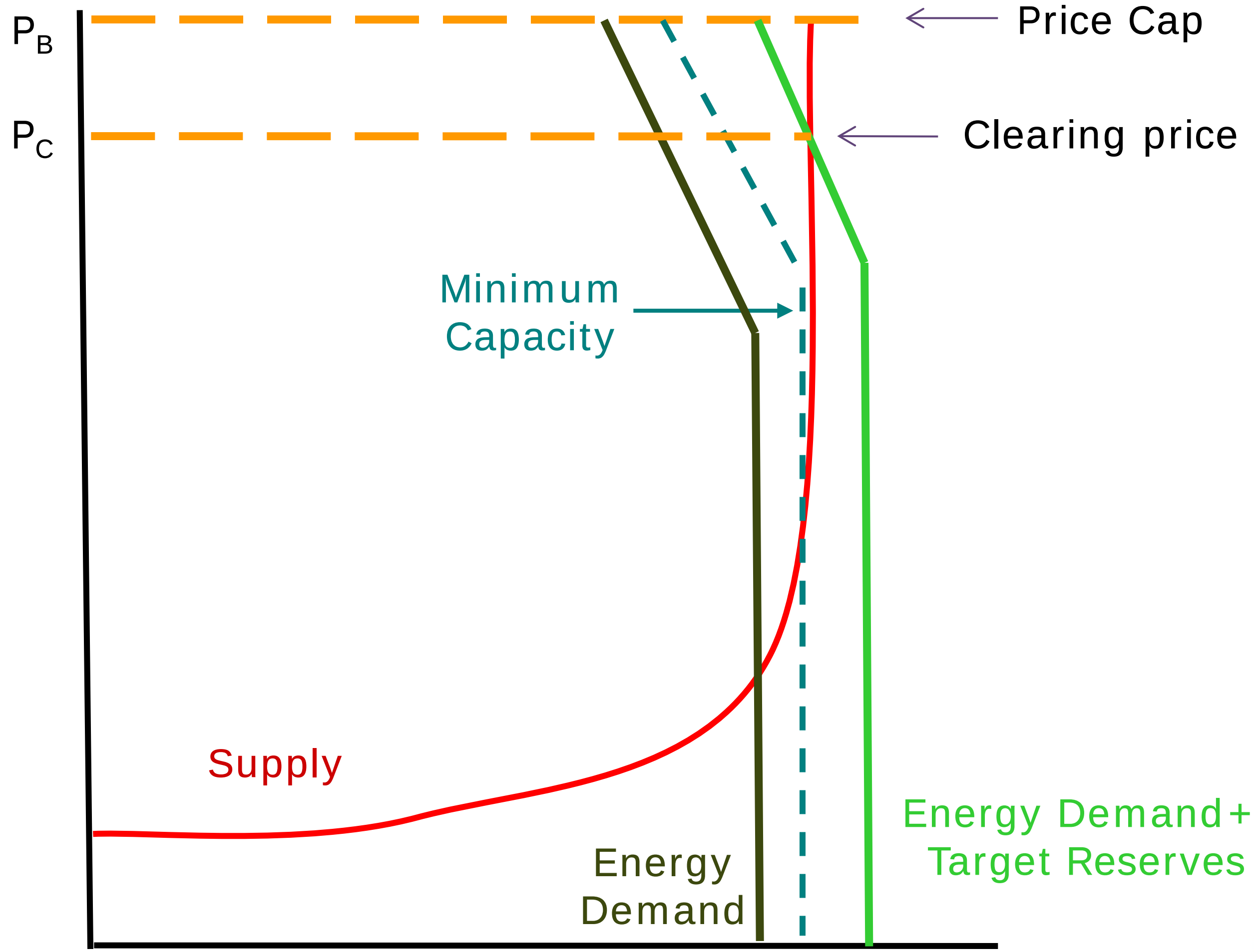
WHY ICAP? Overview

With implementation of open access, there was a potential for the power pools in the Northeast to adopt alternative resource adequacy mechanisms.

- One alternative was to eliminate the pool installed reserve requirements and rely on energy and operating reserve prices to sustain reliability (energy-only pricing).
- The choice was made, however, to convert the existing installed reserve requirements into a market-based installed capacity requirement (ICAP).

The capacity market systems are intended to prevent “free riding” and maintain sufficient “excess” generating capacity to ensure that the energy market clears even with a vertical demand curve for power in real-time.

Supply and Demand in a Energy Only Market



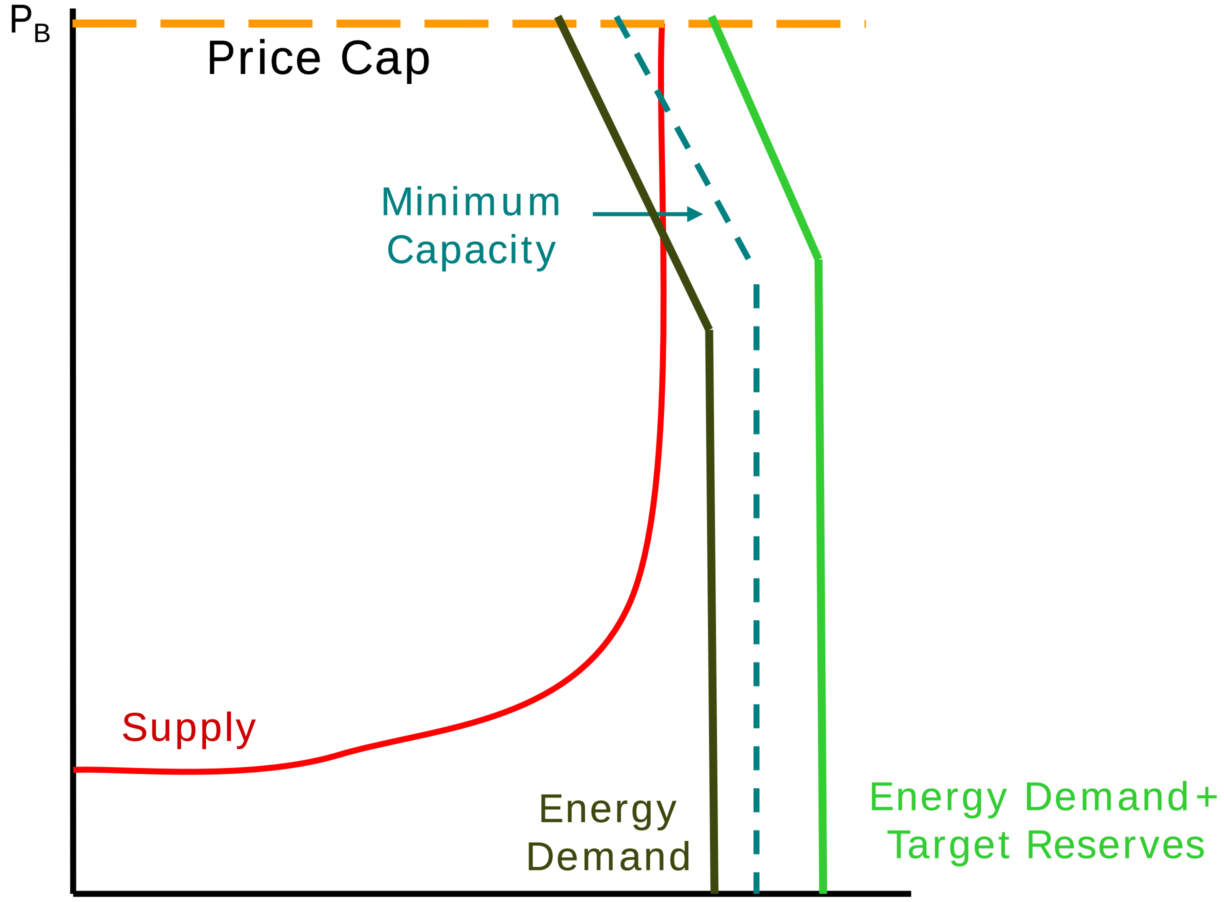
Minimum capacity is the capacity margin below which load shedding is required

WHY ICAP? Energy-Only Markets

An energy-only market would clear in real-time at the intersection of demand and the short-run supply(dispatch) curve.

- Reliability in such a system means that there is sufficient generating capacity to avoid shedding price-insensitive load (firm load), with price-sensitive load voluntarily curtailing consumption when the price of energy is high.
- In such a market design, the price of energy must at times exceed the incremental cost of every generator connected to the system in order for marginal generators to recover their fixed costs in their operating margin.
- The location and shape of the resource dispatch curve would differ between an installed reserve system and an energy-only system due to differences in the amount of generation that would be economic to maintain.

Supply and Demand in a Shortage



Minimum capacity is the capacity margin below which load shedding is required

WHY ICAP? Energy-Only Markets

- On-peak energy prices could be quite high under energy-only pricing, as there would be less capacity available than under a system based on installed reserve requirements.
- On-peak energy consumption would be lower under an energy-only market because real-time pricing would incent consumers to reduce consumption to avoid paying for energy whose cost of production exceeded its value to those consumers.
- At times the price of energy would be set by the bids of price sensitive loads or reserve shortage values.
- Such a market design requires real-time pricing and metering for such price responsive power consumers.

WHY ICAP? Energy-Only Markets

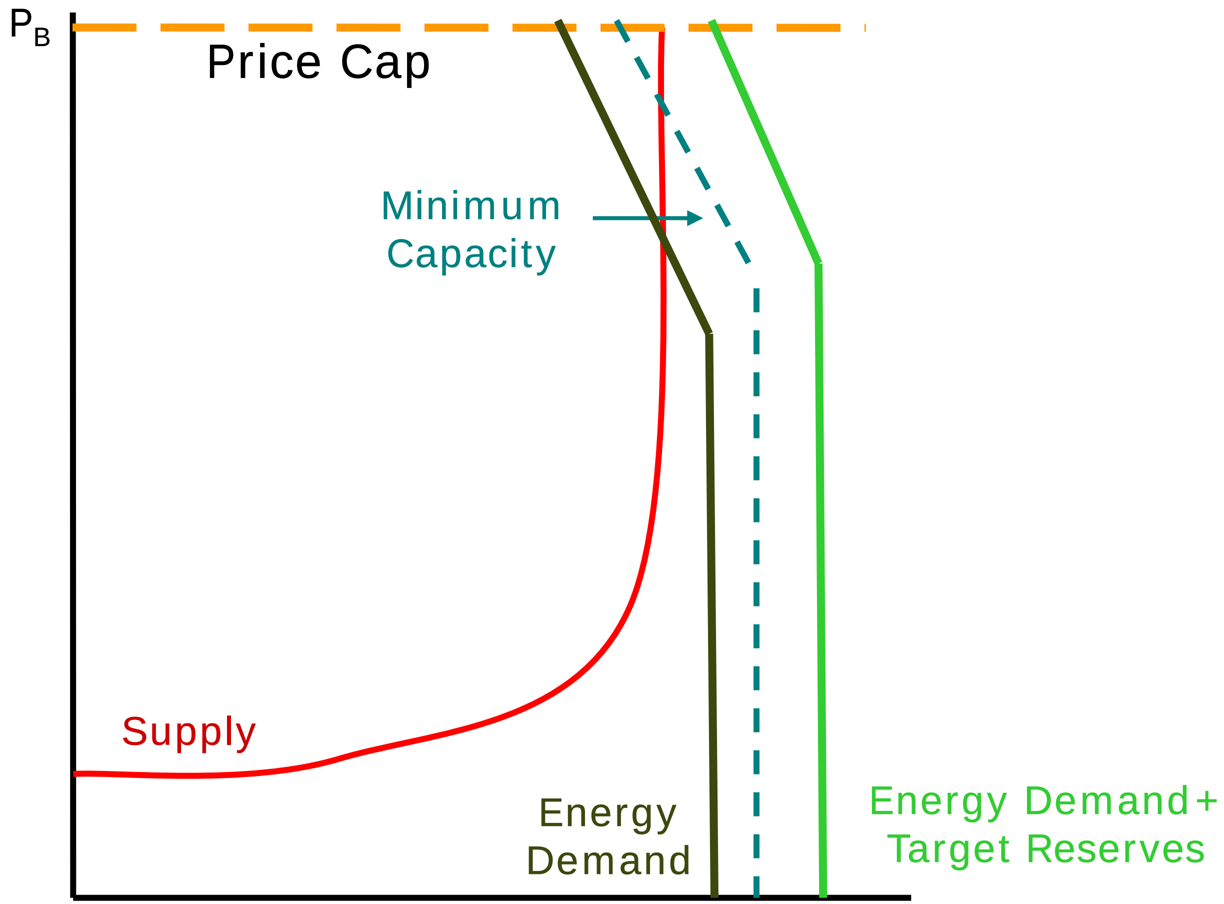
In an energy-only pricing system, reliability is ultimately ensured by price-responsive customer power demand and market driven generation investment decisions, without the need for administratively determined installed reserve requirements.

- Operating reserve margins would be maintained by price-responsive load reducing power consumption in response to high prices.
- Long-term, installed capacity decisions would be left to market decisions based on projected energy market revenues.
- There would be no administrative reserve requirement or capacity payment.

WHY ICAP? Energy-Only Markets

- The real-time electricity market would clear while maintaining reliability, based on real-time energy prices and market-determined installed capacity levels, and generation availability.
- Reliability organizations and regulators would still evaluate resource adequacy on a forward looking basis but these evaluations would provide information, not set mandatory requirements.

Supply and Demand in a Shortage



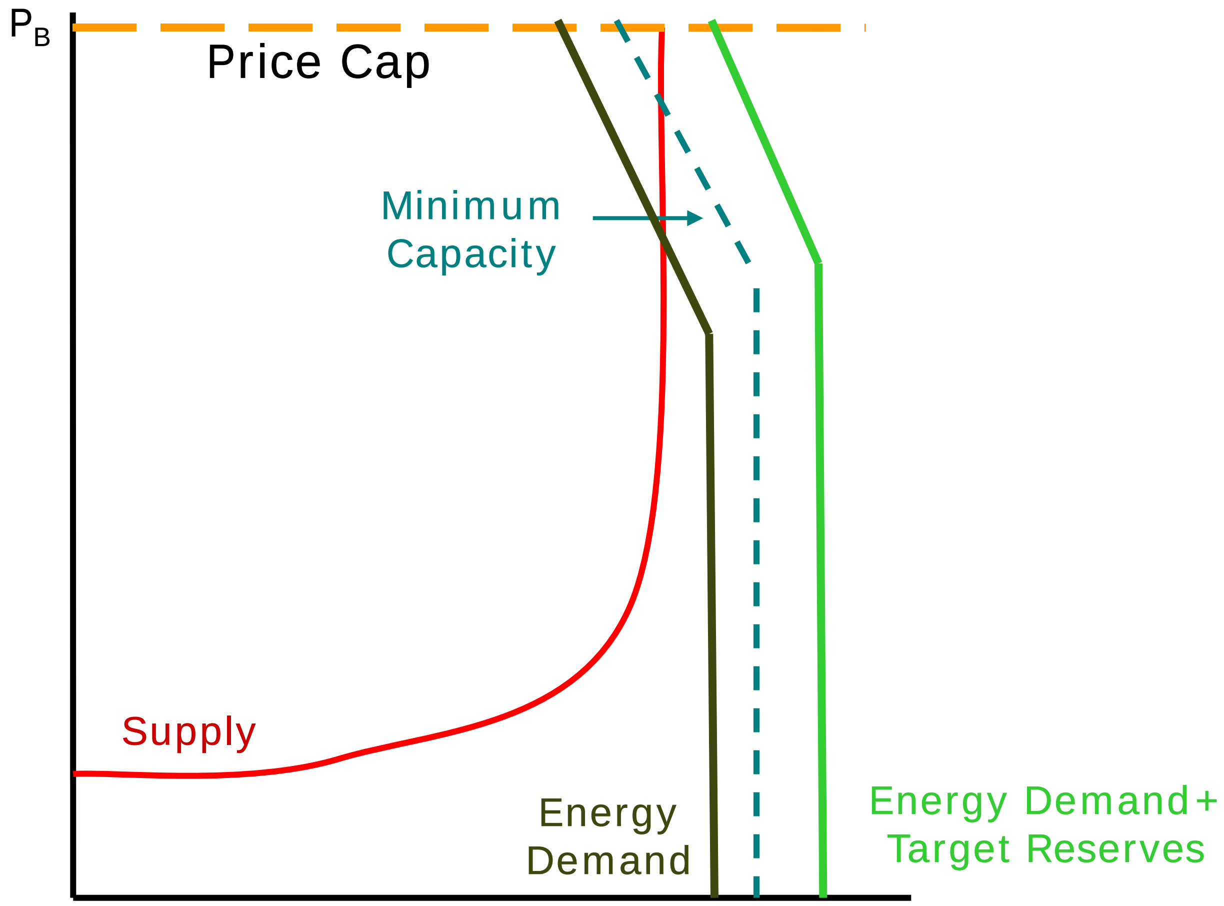
Minimum capacity is the capacity margin below which load shedding is required

WHY ICAP? Overview

The decision not to rely on energy-only pricing when the Eastern power pools became ISOs reflected a number of considerations:

- Maintaining reliability under energy-only pricing requires very high prices during shortage conditions.
- If prices during reserve shortages were determined by cost-based bids or $1,000/MWh bid caps, a large number of shortage hours would be required to support operation of the marginal generator.

Supply and Demand in a Shortage



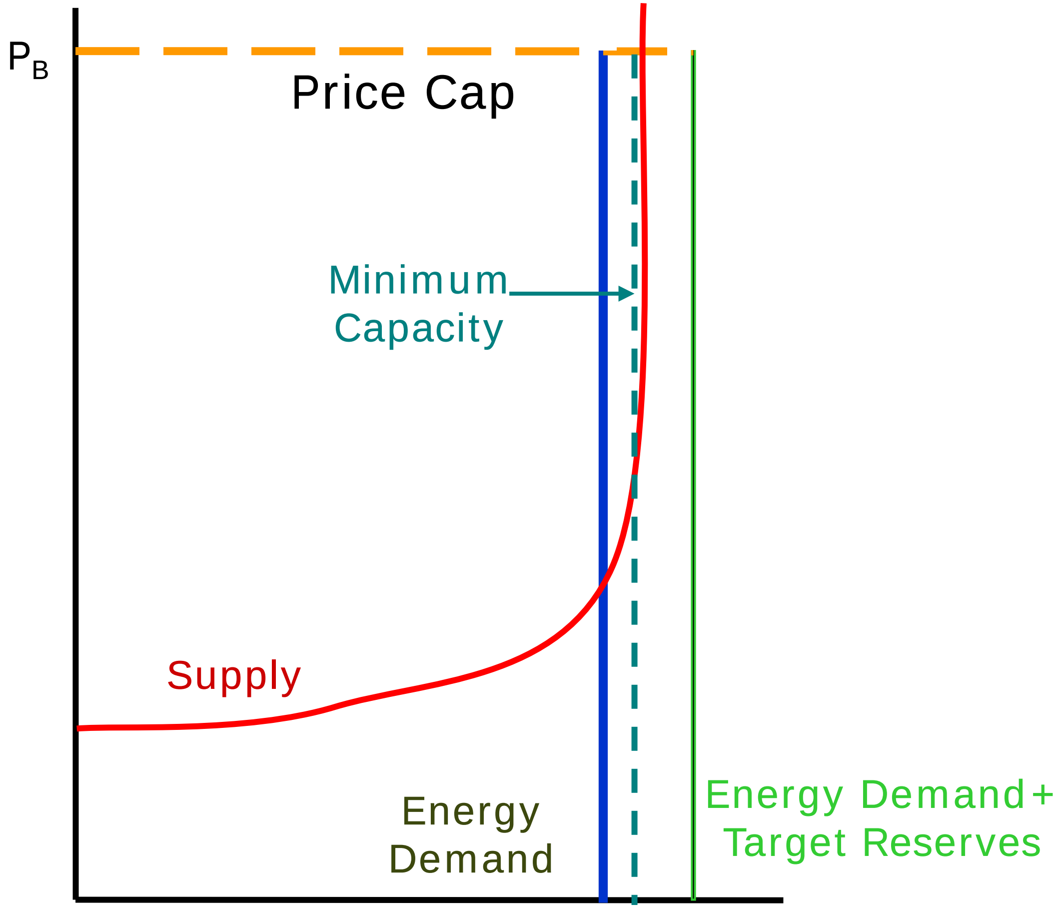
Minimum capacity is the capacity margin below which load shedding is required

WHY ICAP? Overview

- Capacity levels low enough relative to demand to produce such a large number of reserve shortage hours would be accompanied by reduced reliability, particularly since much load might be price responsive only at prices well in excess of $1,000 per megawatt hour.
- A viable energy only market design therefore required prices well in excess of $1,000 per megawatt hour during shortage conductions.

Such an energy only design based on very high shortage prices might have been workable in a market of vertically integrated utilities but was not workable when most northeast states decided to implement retail competition.

Supply and Demand in a Shortage

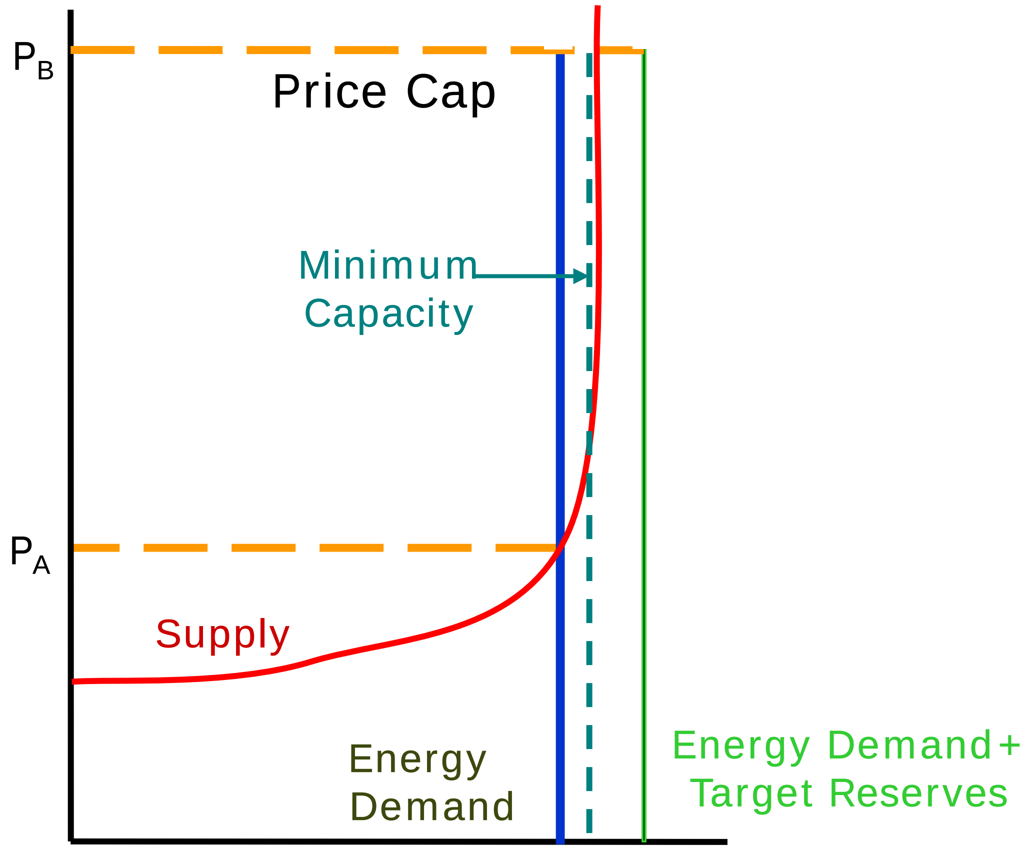


WHY ICAP? Overview

Absent substantial load able to respond to short-term price signals to clear the market, maintaining the level of capacity required to sustain reliability under energy-only pricing requires that resource suppliers anticipate high shortage prices in their capacity decisions.

- One concern with relying on energy only markets in Eastern RTOs in 1997-2000 was that miscalculations during the transition period could adversely impact reliability.

Supply and Demand in a Shortage



WHY ICAP? Overview

- Another concern was that energy-only pricing likely implies that suppliers lacking forward contracts would lose money in most years but occasionally make a lot of money. This model could be problematic from both a regulatory risk and reliability standpoint.
- The retail access plans of many of the states composing the Northeast power pools created additional reliability and regulatory risks due to the lack of long-term contracts and the lack of real-time metering of load at the customer level.

WHY ICAP?

Given these considerations, PJM, New York, and New England chose to begin the transition to competitive power markets by transitioning the pool reserve requirements into capacity market systems to maintain resource adequacy.

B. Basic Capacity Market Design

CAPACITY MARKET DESIGN

Under a capacity market system, a market-wide capacity market requirement is imposed symmetrically on all load-serving entities within the market.

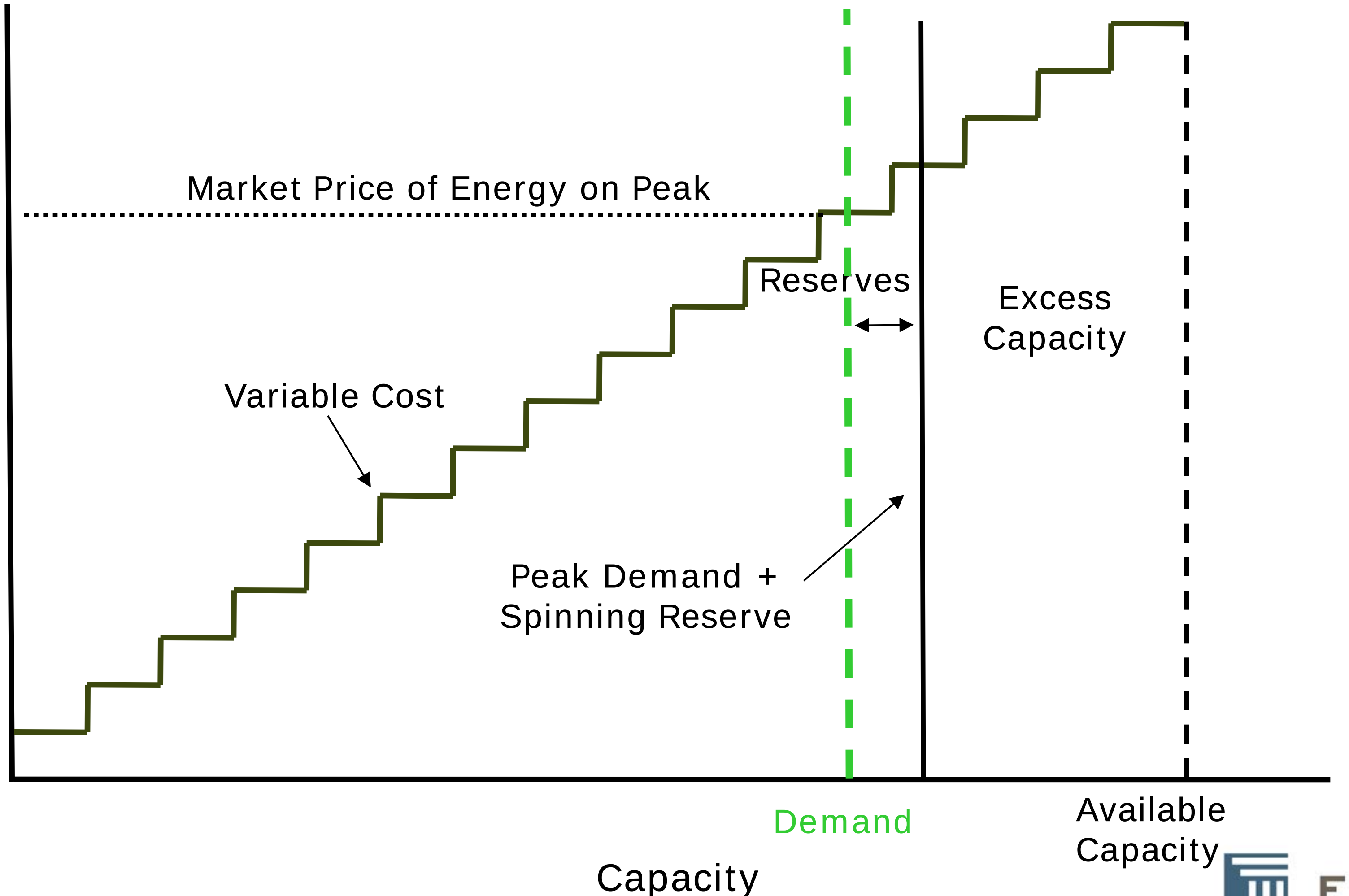
- Load serving entities must demonstrate that they own or have contracted for generating capacity sufficient to meet the installed capacity requirement for their customers.
- If the amount of generation required to be available under the installed capacity requirement exceeds the amount of generation that would have been available in the absence of such a requirement (i.e., the amount warranted by energy market revenues alone), a market for capacity is created.

CAPACITY MARKET DESIGN

In a capacity market system, capacity takes on value in and of itself.

- Marginal units, unprofitable on the margins they earn on energy sales and ancillary services, earn a capacity payment in return for their making their capacity available for operation.
- The capacity payment makes up the “missing money,” which is the difference between the annual cost of operating a unit that is in merit for purposes of meeting the installed capacity requirement, and the margin this unit earns from sales of energy and ancillary services.

CAPACITY MARKET DESIGN



CAPACITY MARKET DESIGN

In an installed capacity system, the wholesale energy market usually clears at the intersection of demand and the variable cost (dispatch) curve with a small number of hours of reserve shortage conditions.

- Reliability in this system means that there is generally sufficient capacity to avoid involuntary load shedding.
- Because the price of energy is generally set by the incremental cost of the energy generated by the marginal units (rather than by shortage pricing), the price is not high enough often enough to cover the full cost of keeping all the units needed to meet the installed capacity requirement in operation over the year.

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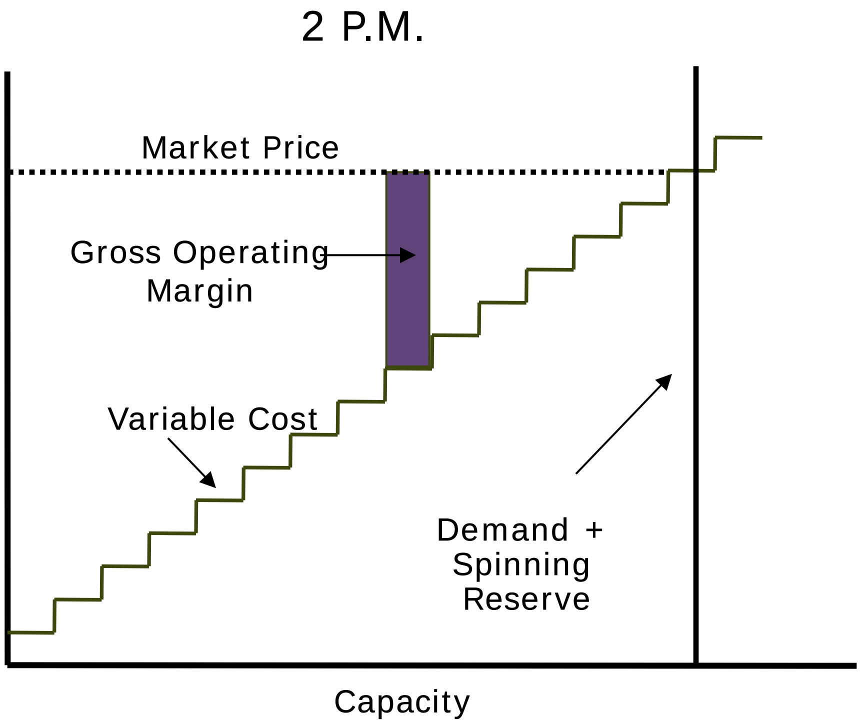
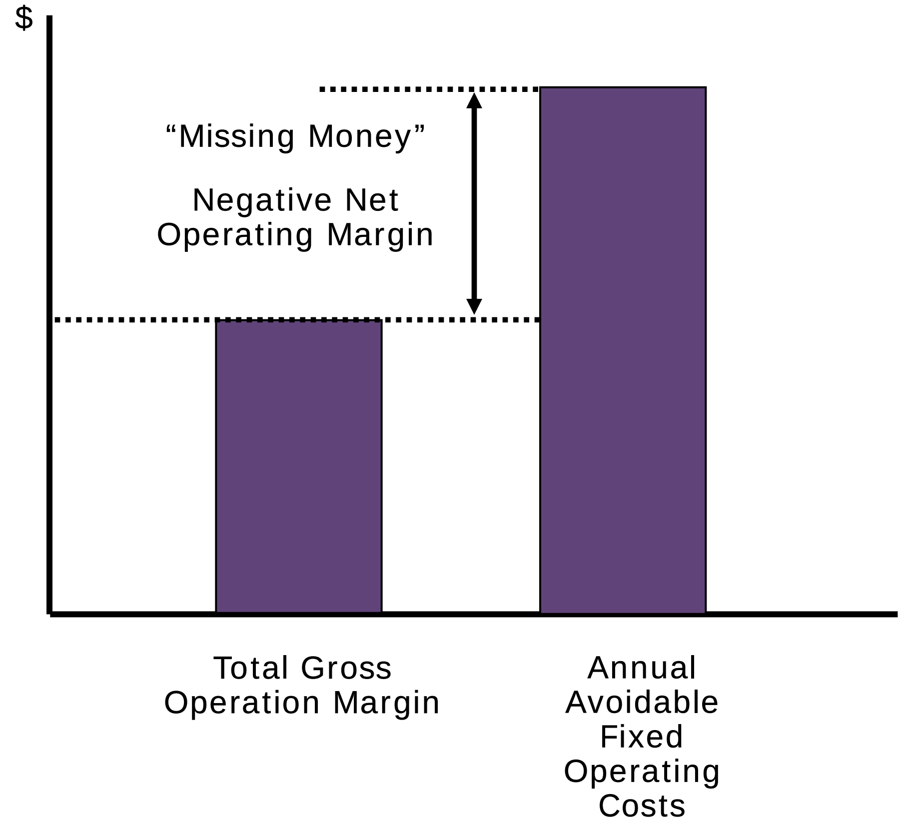
CAPACITY MARKET DESIGN



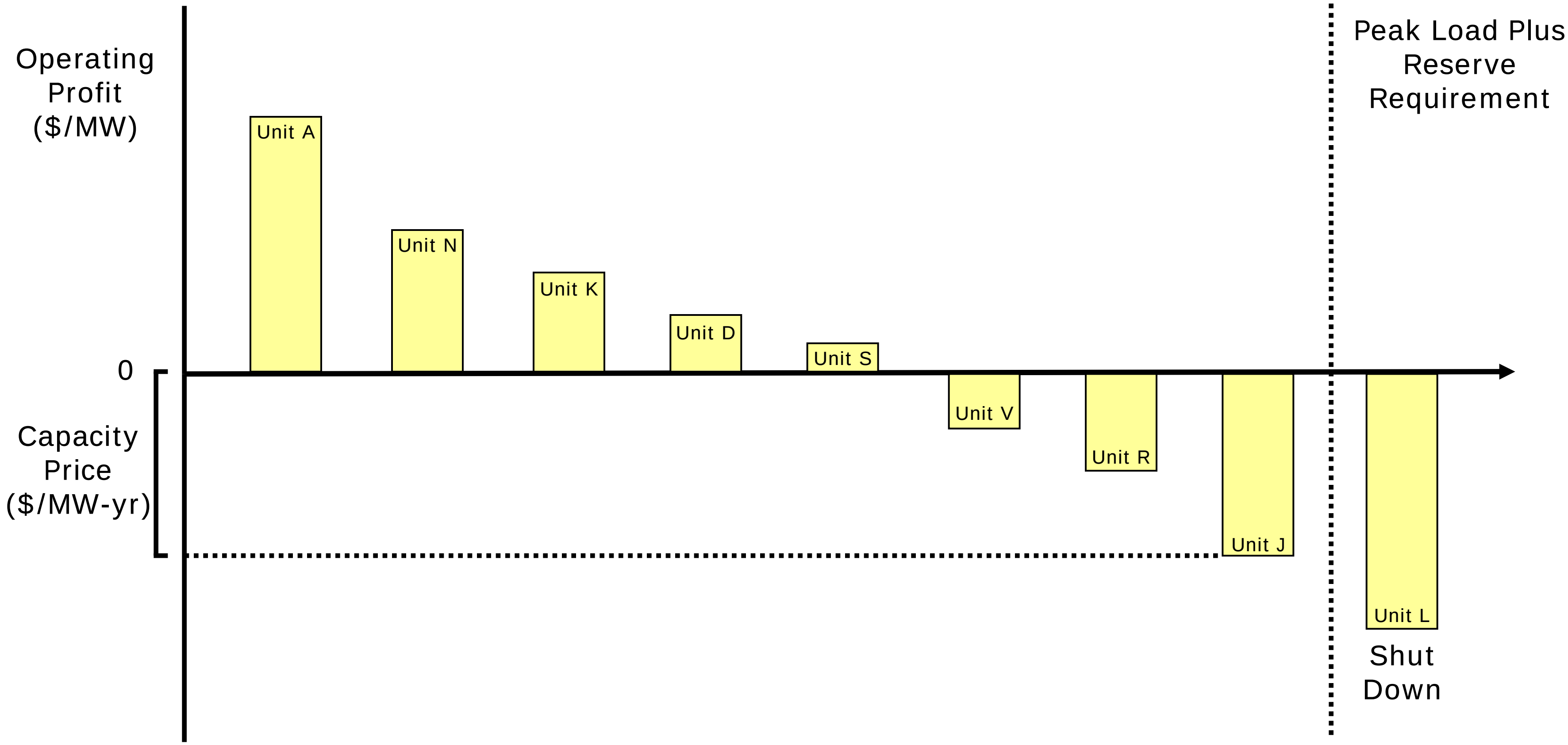
Gross Margin on Energy



Generators earn revenues on their sales of energy and ancillary services, earning margins equal to the difference between their revenues and the variable costs they incur in generating energy.

- Generators also incur fixed costs, some of which can be avoided if the generator chooses not to make itself available for operation (i.e., if it is either mothballed or closes permanently).
- Absent a capacity payment, generators will not remain in operation and available for dispatch if their margins on the sale of energy do not exceed their avoidable fixed operating costs.

Determination of Market Price of Capacity
(Unit Ranked in order of Decreasing Operating Profit Per MW)

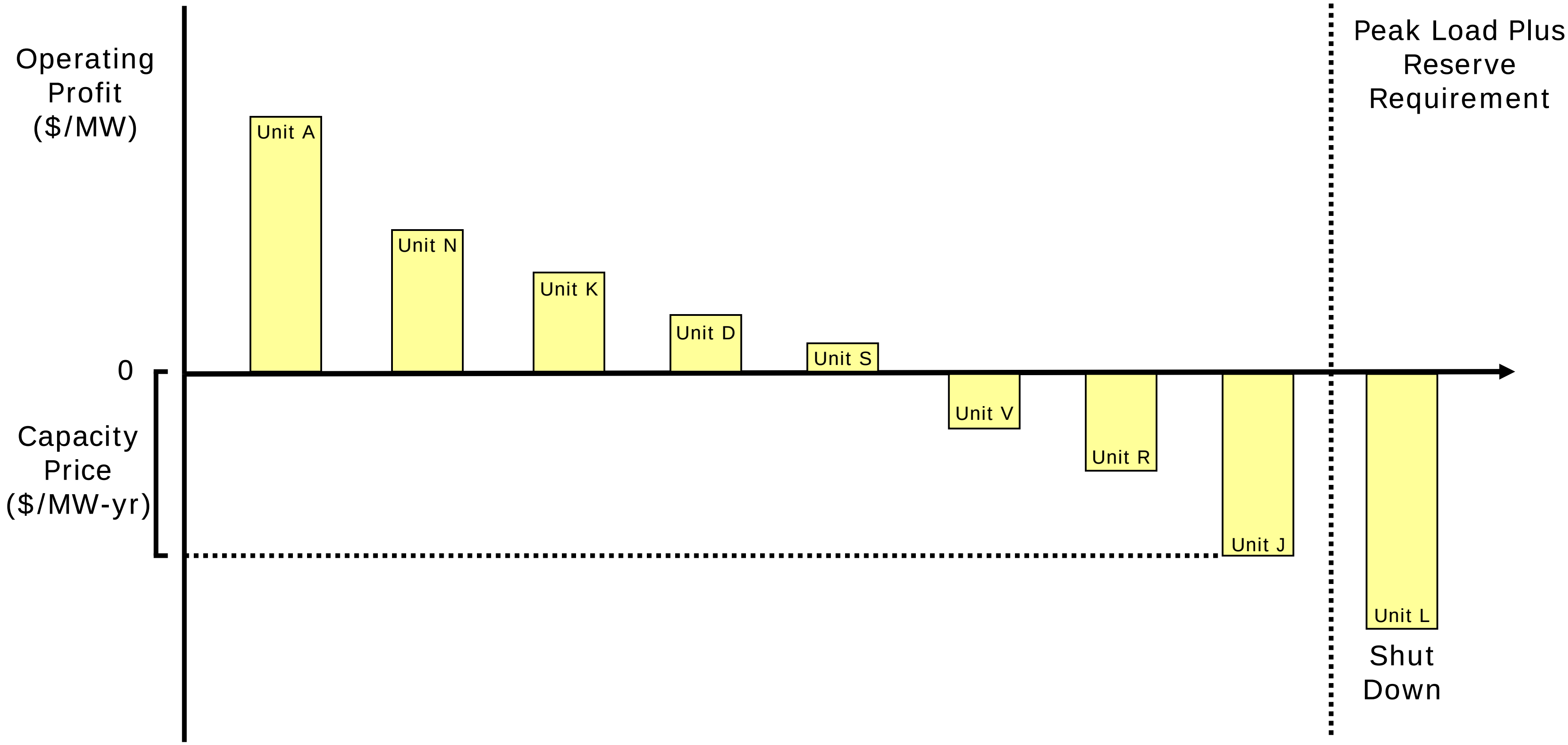


CAPACITY MARKET DESIGN

Units V, R, and J do not recover their going forward costs in energy and ancillary source revenues but their operation is necessary for the RTO to have available the capacity needed to achieve the target level of reliability.

- These operating losses are the “missing money” that arise under market designs that keep energy prices low with bid caps and low values for reserve shortages.

Determination of Market Price of Capacity
(Unit Ranked in order of Decreasing Operating Profit Per MW)

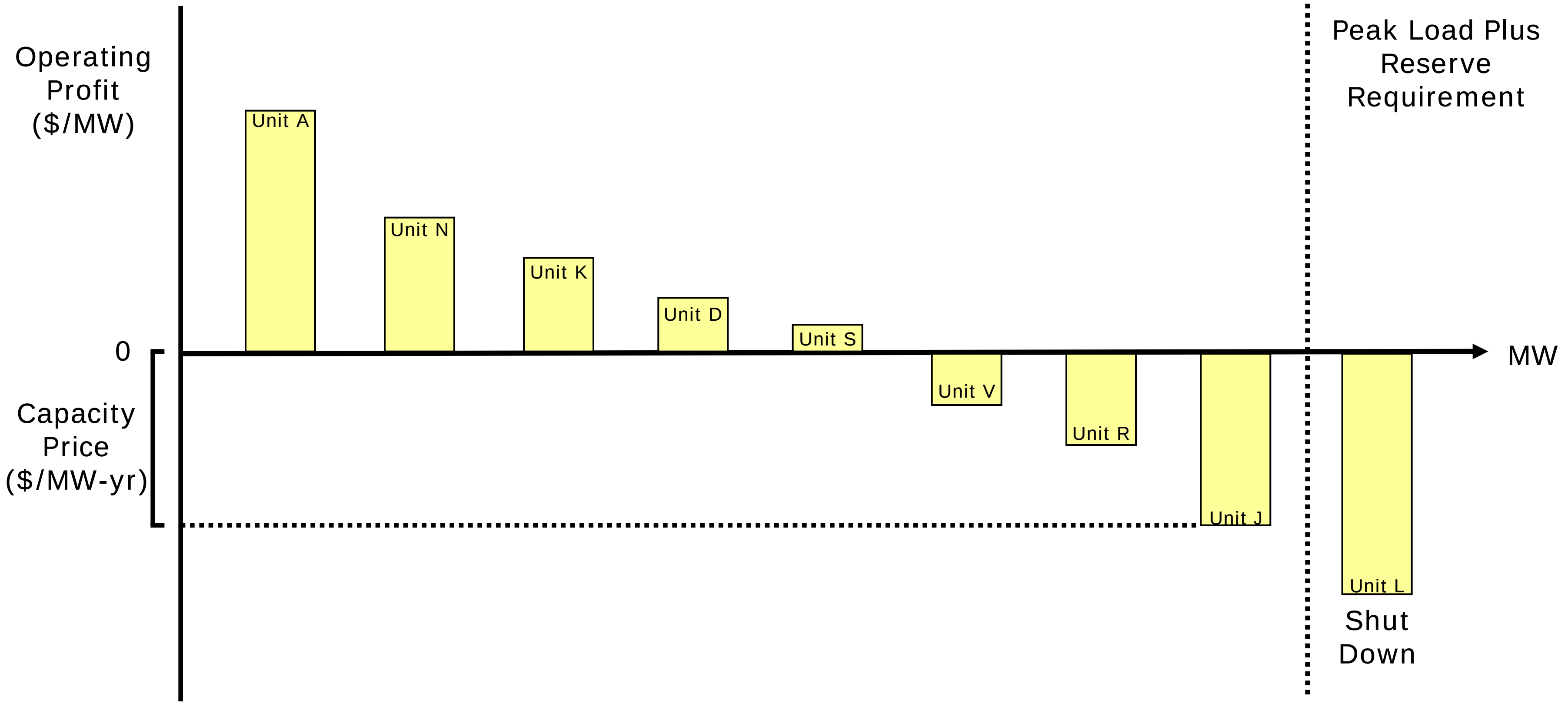


CAPACITY MARKET DESIGN — Price of Capacity

To remain in operation under a market based system, each unit requires a capacity payment at least equal (on an expected value basis) to the difference between its avoidable fixed operating costs and its margins on energy and ancillary services sales.

- In a competitive market, competition among capacity owners will cause the market-clearing capacity payment to approximate the per-MW payment that would induce just enough generation to remain available to enable the capacity requirement to be met.
- All generating capacity contracting to provide installed capacity will be paid the market-clearing price of capacity.
- Between the capacity payments they receive and their margins on energy sales and ancillary services, all units except for Unit L would remain open and earn more than enough to cover their avoidable fixed operating costs.

Determination of Market Price of Capacity
(Unit Ranked in order of Decreasing Operating Profit Per MW)



With a capacity requirement, the capacity payment will be determined by the per-MW payment required to make Unit J at least break even and less than the payment required to keep Unit L in operation.

- Because the market can meet the capacity requirement without Unit L, Unit L will be closed since the market-clearing capacity payment would be insufficient for it to cover its anticipated operating losses.
- Between the capacity payments they receive and their margins on energy and ancillary services sales, each of the other units remaining open would make more than enough to cover their avoidable fixed operating costs.

CAPACITY MARKET DESIGN Price of Capacity

- In the real world the market clearing capacity price also depends on expected future capacity prices and the cost of mothballing capacity and returning it to service. Resources may remain in operation despite a capacity payment that is less than their going forward costs, if they expect capacity prices to rise in the near future.

C. Defining Capacity Requirements

CAPACITY REQUIREMENTS

A fundamental characteristic of capacity market systems is that there is a predefined capacity requirement, typically set by the ISO or an ISO related reliability organization such as the New York State Reliability Council.

- The capacity requirement is set in advance of the operating year based on projected peak loads, projected generation outage rates and availability, and projected import availability with an allowance for the uncertainty associated with these projections.

CAPACITY REQUIREMENTS

Because the nominal capacity requirement depends on projected generation outage and availability rates, the nominal capacity requirement depends on which resources provide capacity.

- The more high outage rate, or low availability, resources are relied upon to provide capacity, the higher the nominal capacity requirement needs to be.

CAPACITY REQUIREMENTS

The capacity requirement only indirectly accounts for the impact of power prices on demand.

- High fuel costs have the potential to raise electricity prices and reduce peak demand, reducing needed capacity.
- The demand forecast used to define future capacity requirements will generally reflect current power and fuel prices.
- The further out in time capacity requirements are being projected, the greater the potential for significant changes in fuel prices to impact power costs and demand.

CAPACITY REQUIREMENTS

While traditional capacity market systems establish a single capacity requirement, the actual amount of installed capacity that will be needed to meet load is uncertain.

- Weather conditions vary from year to year;
- Extreme weather may by chance fall on a weekend or holiday, reducing load;
- The amount of capacity unavailable on the peak days due to deratings or outages is highly variable;
- The supply available during peak load hours from intermittent resources is variable;
- The amount of supply available from adjacent control areas on the peak day is uncertain.

D. Overview of Capacity Market Evolution in the Northeast

Overview of Market Evolution PJM

June 1, 1999	Daily non-locational capacity market introduced.
June 1, 2007	RPM capacity market instituted
April 11, 2011	Buyer side mitigation (MOPR) rules revised
June 1, 2014	Import limits implemented (ER14-503)
August 2015	First Capacity Performance Product auction

Overview of Market Evolution NYISO

Nov. 1999 NYISO begins operation with monthly capacity market, 6 month voluntary strip auctions and 3 zones.

May 2003 Sloped Demand Curve introduced

March 27, 2008 Buyer side mitigation implemented, ER07-39

May 2014 Lower Hudson Valley Zone added (Docket ER13-1380)

Overview of Market Evolution

ISO NE

May 1999	ISO NE begins operation with OPCAP and ICAP markets.
March 2000	OPCAP market eliminated
August 2000	ICAP market eliminated, replaced with .17/kw penalty
April 1, 2001	$4.87/kw month penalty implemented
May 2002	Limits on capacity imports from New York implemented
April 2003	Monthly Supply Auction implemented
March 2004	ISO NE files locational ICAP Proposal

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Overview of Market Evolution ISO NE

March 2006	FCM Settlement filing
Dec 2007	FCM market design filed
Dec 2007	FCM transition ICAP mechanism implemented
Feb 2008	FCA 1 auction for 2010-2011
June 2010	FCA 1 delivery period begins
April 2012	FCA 6 auction Four zones enforced in FCM auction
Feb 2015	FCA 9 auction Pay for performance, demand curve
2018-2019	First pay for performance delivery year

II. Fundamental Capacity Market Issues

CAPACITY MARKET ISSUES

Installed capacity systems have several limitations in an open access electricity market:

- Capacity market systems maintain reliability and ensure that the electricity market clears by maintaining more generating capacity than is likely to be needed to reliably meet load. Maintaining this excess capacity is expensive.
- A potentially complex set of rules is required to govern the location of qualifying capacity.
- A further set of rules is required to govern generator availability.
- There is a potential for free-riding by load serving entities not required to maintain installed capacity and too little incentive for power consumers to become price-responsive.

CAPACITY MARKET ISSUES

- Absent long-term contracts, the capacity requirement may be conducive to the exercise of short-term buyer or seller market power, but the exercise of market power can be difficult to clearly identify, or to appropriately mitigate, in short-term capacity markets.
- Special rules are needed to incent demand response because energy prices do not reflect the full cost of reliably meeting incremental load.
- Additional rules are required to account for the value of imported power and external capacity resources
- Accounting for the value of intermittent and energy limited resources can be difficult.

A. Capacity Deliverability and Locational Requirements

DELIVERABILITY — Minimum Interconnect

PJM, NEPOOL and the NYISO rely on locational pricing for congestion management in their energy markets.

- This has enabled all three ISOs to adopt a “minimum interconnect” standard for generators selling energy into the market.
- A new generator satisfies the “minimum interconnect” standard if it is able to deliver its power to the transmission grid without adversely affecting reliability and its interconnection (at zero energy dispatch) does not reduce transfer capability.

Capacity market deliverability tests are a central issue in implementing capacity market systems in decentralized electricity markets, particularly with respect to the interconnection of new generators.

- LMP pricing in energy markets provides new generators with incentives to site themselves efficiently, without restricting competition. Congestion impacts are reflected in the LMP energy prices and thus in the revenues of both incumbents and entrants.
- Generators receive capacity payments, however, whether they operate or not, so there is no locational price signal in a capacity market absent some form of deliverability test or locational capacity market.

DELIVERABILITY Issues

All three Northeast ISO's have struggled with how to apply some form of deliverability test to resource suppliers in the capacity market. Such a test would ideally meet three objectives.

- No barriers to entry: The deliverability test should preserve the condition for efficient entry that the entrant's full generating costs need only be less than the avoidable generating costs of an incumbent at the same location.
- Permit long-term capacity contracts: The deliverability test should permit long-term bilateral contracts for capacity. This requires a mechanism that permits capacity sellers to enter into long-term capacity contracts and hedge themselves against the impact of entry on deliverability.
- Reflect reliability criteria: The deliverability test needs to ensure that resources eligible for capacity payments make an appropriate contribution to reliability under stressed system conditions.

DELIVERABILITY PJM

The PJM process for testing deliverability has two components. First, the ability of an electrical area to export energy to the remainder of the control area is tested to ensure that capacity is not bottled.

- All generation in the electrical area collectively either passes or fails.
- Under PJM's initial capacity market design, existing capacity suppliers were grandfathered as deliverable so failure to collectively pass the test, in effect, excluded new generation within the region from the capacity market. This prevented new generation from undercutting the capacity offers of incumbents unless the entrants funded transmission investments sufficient to reliably deliver energy to aggregate control area load throughout PJM.
- This grandfathering allowed existing generators to enter into multi-year capacity market contracts but violated the efficient entry condition.

DELIVERABILITY PJM

Second, the CETO/CETL test is passed if the amount of energy that a subarea must be able to import to remain within MAAC reliability criteria (CETO) is less than the transfer limit (CETL).

- The region, not the resource, passes or fails the CETO/CETL test.
- Failure of the deliverability test may result in a subarea being unable to receive full capacity credit for remote resources delivered to that subarea.
- The test does not define which load serving entities must contract for local generation or define which load serving entities can contract for remote resources to meet their capacity requirements.

DELIVERABILITY PJM

PJM addressed these limitations of its initial capacity market system when it implemented the RPM design in 2007 and applied four local deliverability areas in the first three RPM auctions (delivery years 2007/2008, 2008/2009, 2009-2010)

- RTO
- PJM Mid-Atlantic region plus APS
- Eastern MAAC (PSE&G, JCP&L, PECO, Atlantic Electric, Del Marva Power & Light, Rockland Electric Co)
- Southwestern MAAC (Pepco and BG&E)

Capacity only needed to be deliverable within these regions and capacity prices could, and often did, clear at different prices across these regions.

PJM $ per Megawatt Year

Delivery Year	RTO		MAAC		EMAAC		PS		DPL South		PSEG North		SWMAAC		Pepco		ATSI	
	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year	$/MW-Day	$/MW-Year
2007-2008	40.8	14892	40.8	14892	197.67	72149.55	197.67	72150	197.67	72149.55	197.67	72149.55	188.54	68817.1	188.54	68817.1	N/A	
2008-2009	111.92	40850.8	111.92	40850.8	148.8	54312	148.8	54312	148.8	54312	148.8	54312	210.11	76690.15	210.11	76690.15	N/A	
2009-2010	102.04	37244.6	191.32	69831.8	191.32	69831.8	191.32	69832	191.32	69831.8	191.32	69831.8	237.33	86625.45	237.33	86625.45	N/A	
2010-2011	174.29	63615.85	174.29	63615.85	174.29	63615.85	174.29	63616	186.12	67933.8	174.29	63615.85	174.29	63615.85	174.29	63615.85	N/A	
2011-2012	110	40150	110	40150	110	40150	110	40150	110	40150	110	40150	110	40150	110	40150	N/A	
2012-2013	16.46	6007.9	133.37	48680.05	139.73	51001.45	139.73	51001	222.3	81139.5	185	67525	133.37	48680.05	133.37	48680.05	N/A	
2013-2014	27.73	10121.45	226.15	82544.75	245	89425	245	89425	245	89425	245	89425	226.15	82544.75	247.14	90206.1	27.73	10121.45
2014-2015	125.99	45986.35	136.5	49822.5	136.5	49822.5	136.5	49823	136.5	49822.5	225	82125	136.5	49822.5	136.5	49822.5	125.99	45986.35
2015-2016	136	49640	167.46	61122.9	167.46	61122.9	167.46	61123	167.46	61122.9	167.46	61122.9	167.46	61122.9	167.46	61122.9	357	130305
2016-2017	59.37	21670.05	119.13	43482.45	119.13	43482.45	219	79935	119.13	43482.45	219	79935	119.13	43482.45	119.13	43482.45	114.23	41693.95
2017-2018	120	43800	120	43800	120	43800	215	78475	120	43800	215	78475	120	43800	120	43800	120	43800
Average		33998.09		50799.37		58064.86		71756		61197.23		68969.74		60486.47		61182.96		54381.35

DELIVERABILITY PJM

Beginning in the 2010/2011 deliverability year, PJM applied 23 local deliverability areas in the RPM auction but only eight local deliverability areas have so far had requirements for local generation that were large enough that they lead to a separate market clearing price for the local area.

- RTO
- PJM Mid-Atlantic
- Eastern MAAC
- Southwestern MAAC
- Delmarva Power & Light South
- PSEG North
- Pepco
- ATSI

DELIVERABILITY PJM

The definition of additional local deliverability areas takes into account Regional Transmission Expansion Plan (RTEP) analysis of constrained transmission facilities; CETL/CETO calculations; and real-time congestion patterns.

DELIVERABILITY New York

The initial New York capacity market system was developed with high cost load pockets in mind: Deliverability of capacity resources was to be ensured by establishing locational capacity Requirements for New York City and Long Island.

- For the 2015-2016 capacity year, load serving entities serving load in New York City were required to procure ICAP equal to at least 85.5 percent of peak load from NYC resources.
- Load serving entities serving load in Long Island are required to procure ICAP equal to at least 103.5 percent of peak load from Long Island resources.

DELIVERABILITY New York

The New York ISO local capacity requirements are determined based on GE-MARS simulations of the amount of local capacity needed to maintain the loss of load expectation for the state at .1 days per year if total New York capacity is at the target level.

DELIVERABILITY — New York

The initial New York locational ICAP system provided incentives for generation to be constructed within and transmission built to serve the high cost load pockets of New York City (Zone J) and Long Island (Zone K), but had several limitations.

- Prior to introduction of the capacity market demand curve, the price of capacity in the constrained areas, particularly New York City, tended to clear at the capacity market price cap.
- The locational requirements did not address deliverability constraints within New York City or Long Island, or elsewhere in the state (e.g., east of Central East or South of Pleasant Valley Leeds).

NYISO Strip Market Capacity Prices ($/kW – Month) Summer 2003 – Summer 2015

Capability Period	Zone J	Zone K	ROS	LHV
Summer 2003	$ 11.22	$ 9.41	$ 1.67	
Winter 2003-2004	$ 6.55	$ 4.00	$ 1.17	
Summer 2004	$ 11.15	$ 8.00	$ 1.68	
Winter 2004-2005	$ 6.68	$ 4.00	$ 0.60	
Summer 2005	$ 11.68	$ 8.00	$ 0.75	
Winter 2005-2006	$ 5.11	$ 0.68	$ 0.62	
Summer 2006	$ 12.35	$ 6.50	$ 1.44	
Winter 2006-2007	$ 5.67	$ 3.50	$ 2.50	
Summer 2007	$ 12.37	$ 3.75	$ 2.25	
Winter 2007-2008	$ 5.32	$ -	$ 1.91	
Summer 2008	$ 6.50	$ 2.80	$ 2.67	
Winter 2008-2009	$ 2.79	$ 1.77	$ 1.77	
Summer 2009	$ 6.75	$ 3.01	$ 3.01	
Winter 2009-2010	$ 4.65	$ 1.75	$ 1.75	
Summer 2010	$ 12.90	$ 2.47	$ 2.47	
Winter 2010-2011	$ 4.60	$ 0.39	$ 0.39	
Summer 2011	$ 13.54	$ 0.55	$ 0.55	
Winter 2011-2012	$ 2.70	$ 0.15	$ 0.15	
Summer 2012	$ 11.70	$ 1.42	$ 1.25	
Winter 2012-2013	$ 4.50	$ 2.25	$ 0.82	
Summer 2013	$ 14.80	$ 7.20	$ 4.20	
Winter 2013-2014	$ 7.54	$ 4.00	$ 2.58	
Summer 2014	$ 16.24	$ 6.39	$ 5.15	$ 9.96
Winter 2014-2015	$ 8.45	$ 3.00	$ 2.90	$ 5.90
Summer 2015	$ 15.50	$ 5.30	$ 3.50	$ 8.50

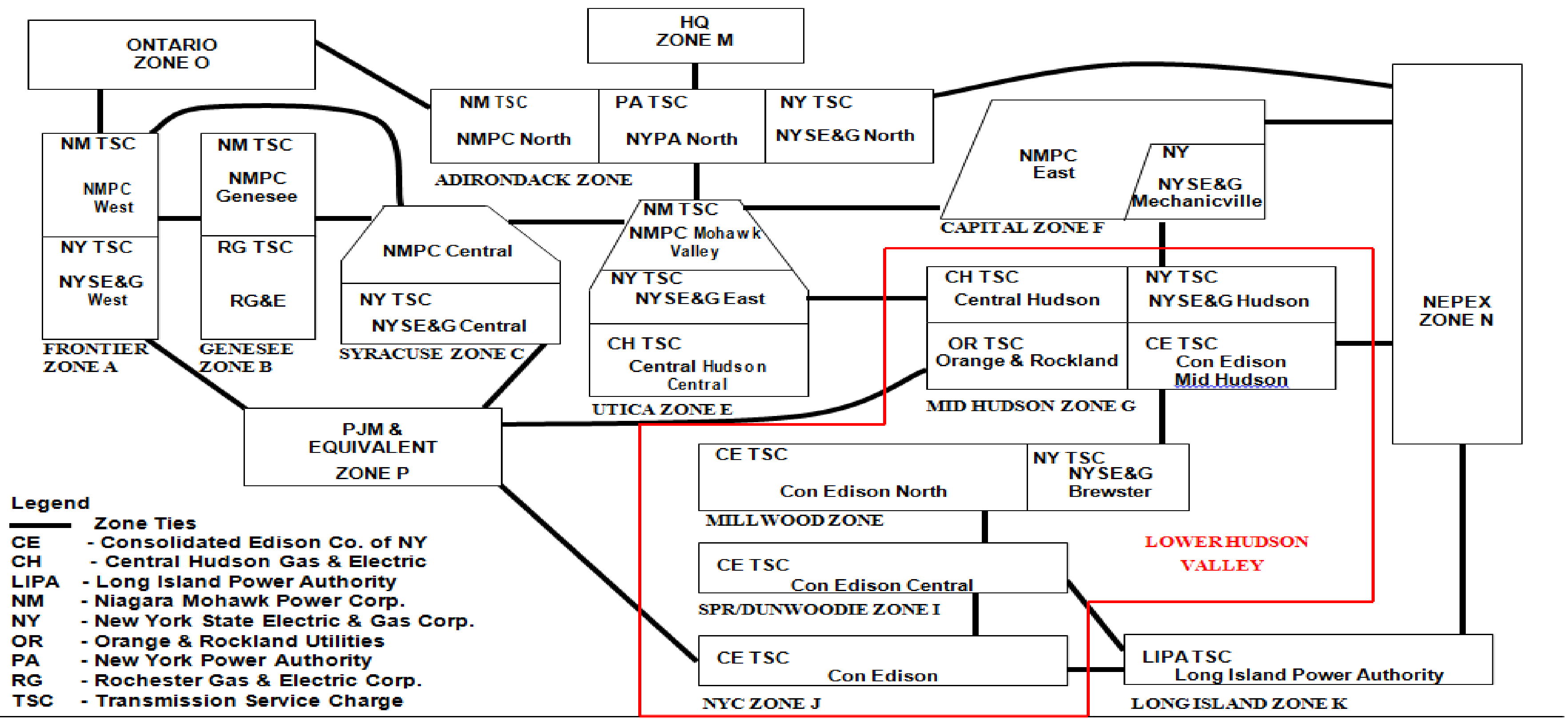
Source: NYISO Strip Auction Summary
http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do

DELIVERABILITY New York

The New York ISO subsequently introduced a deliverability requirement to address the potential for capacity resources to not be deliverable within the region in which they are located.

- This requirement grandfathered existing capacity market resources as deliverable and prevents new resources in upstate New York from competing with existing resources in the “rest of state” region unless they pay for transmission upgrades into Southeastern New York or buy deliverability (CRIS rights) from incumbent generators.
- These upgrades are not needed for new capacity to displace existing capacity, so the delivery requirement could potentially keep capacity prices artificially high in upstate New York.

Maps of the NYCA Transmission Districts and Zones
(Version 1.0)



Attachment C: Maps of the NYCA Transmission Districts and Zones (Version 1.0)

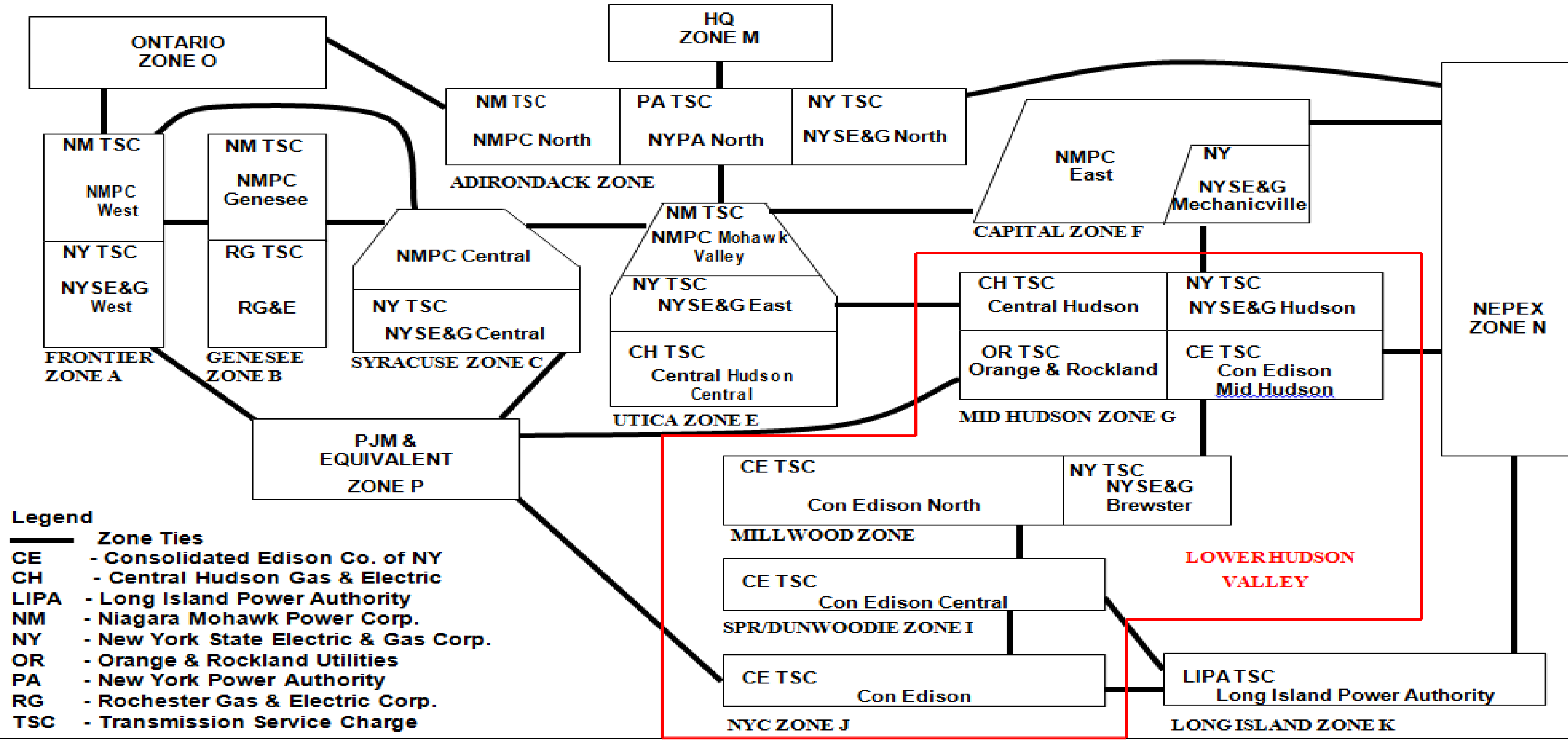
NYISO Capacity Market Products (12/04/2003)

DELIVERABILITY New York

The initial New York ISO capacity market "rest of state" region included capacity in Western New York (West of Central East), capacity east of central east and north of Pleasant Valley Leeds (roughly Zone F), and capacity south of Pleasant Valley Leeds but located outside Zone J and K (roughly zones G, H, and I).

- When Central East or Pleasant Valley Leeds bound in the New York ISO deliverability test, new generation capacity located in Western New York was not "deliverable" throughout the "rest of state" region under the deliverability rule, and therefore could not qualify as a capacity resource.

Maps of the NYCA Transmission Districts and Zones
(Version 1.0)



Attachment C: Maps of the NYCA Transmission Districts and Zones (Version 1.0)

NYISO Capacity Market Products (12/04/2003)

DELIVERABILITY New York

After a long FERC process, the New York ISO established a new capacity market zone east of Central East and south of Leeds-Pleasant Valley (lower Hudson Valley) that was included in capacity market auctions for the period beginning in May 2014.

- The 2015-2016 local capacity requirement for Lower Hudson Valley is 90.5% of forecast peak load.

DELIVERABILITY New England

New England's capacity market system initially lacked a locational requirement, so surplus capacity in regions such as Maine drove the price of capacity close to zero, even for resources located in the Connecticut and Boston load pockets, that were not in surplus.

- These artificially low capacity prices required more and more RMR contracts to keep generation needed to meet load within these load pockets in operation.
- New England's forward capacity market design (FCM) attempted to address locational capacity requirements with "local sourcing requirements."

DELIVERABILITY — New England

The local sourcing requirement of New England's forward capacity market was supposed to ensure that all capacity is located where it can make an appropriate contribution to reliability and that sufficient capacity is located within constrained areas to meet reliability requirements.

- Zonal constraints were initially enforced in the auction if existing capacity located within the zone, less retirements and capacity exports, is less than the local sourcing requirement.
- Zonal constraints are always enforced in the auction for export constrained zones.

DELIVERABILITY New England

The initial FCM auction design in which zonal constraints were only enforced if there was not enough existing capacity to meet the local sourcing requirement did not ensure that reliability requirements were met if the unconstrained clearing price was less than the going forward cost of some existing capacity.

- Unconstrained clearing prices repeatedly fell below the costs of capacity needed to maintain reliability in individual load zones.

DELIVERABILITY New England

- The offers of the Salem Harbor units should have set clearing price for capacity in Northeast Massachusetts where ISO New England determined they were needed to avoid transmission over loads in the third and fourth auctions. The local sourcing requirements used to enforce zonal capacity requirements were much less than needed to avoid transmission overloads.
- Vermont Yankee should have set the clearing price for generation in Vermont in the fourth and fifth auctions.
- As of FCA 6, ISO New England began enforcing at least four zones in the capacity market auction.

ISO-NE Capacity Clearing Price, Capacity Periods 2010 – 2011 through 2018 - 2019

		ROP	CT	NEMA-Boston	SEMA-RI	Maine
Auction	Capacity Period	$/kW-Month	$/kW-Month	$/kW-Month	$/kW-Month	$/kW-Month
FCA 1	2010-2011	4.5				4.5
FCA 2	2011-2012	3.6				3.6
FCA 3	2012-2013	2.95				2.95
FCA 4	2013-2014	2.95				2.95
FCA 5	2014-2015	3.21				3.21
FCA 6	2015-2016	3.43				3.43
FCA 7	2016-2017	3.15	3.15	15/6.66		3.15
FCA 8	2017-2018	15/7.025	15/7.025	15	15/7.025	15/7.025
FCA 9	2018-2019	9.55	9.55	9.55	17.73/11.08	

Source: Forward Capacity Market Result Reports, FCA 1-9:
http://www.iso-ne.com/markets-operations/markets/forward-capacity-market

DELIVERABILITY New England

Capacity prices cleared at the price floor through FCA 6 pool wide and outside Boston in FCA 7.

- With continuing exit of capacity, capacity prices then rose to the price cap pool wide in FCA 8, although existing capacity were subject to an additional price cap at half that level.
- Prices remained fairly high with the demand curve in FCA 9, with the highest prices in the Southeastern Mass, Rhode Island zone.

DELIVERABILITY Interconnection

A capacity based resource adequacy system as opposed to an energy only market, requires deliverability analysis on interconnecting generators, contributing to the complexity and length of the interconnection study process.

- This is true even in regions which do not currently have formal capacity markets such as California and the Midwest ISO.
- Interconnection of new generation may affect the deliverability of existing generation.
- Different combinations of new interconnecting generation will have different impacts on durability.

B. Transmission Expansion

TRANSMISSION EXPANSION

Reliance on capacity markets to sustain resource adequacy requires rules to account for the impact of transmission upgrades on resource adequacy locational capacity requirements.

- Non-locational capacity markets generally account for the impact of transmission upgrades through deliverability requirements.
- Locational capacity markets generally award transmission upgrades some form of capacity deliverability right to the extent that an upgrade increases transfer capability into a local capacity market.

TRANSMISSION EXPANSION

The New York ISO awards unforced capacity delivery rights (UDRs) to transmission projects for controllable lines that allow the delivery of additional energy into New York City (Zone J) Long Island, (Zone K), and now Lower Hudson Valley (Zones G, H, I and J).

- An UDR plus upstate capacity meets the local capacity requirement

TRANSMISSION EXPANSION ISO New England

ISO New England similarly awards CTRs to market participants that pay for transmission upgrades not funded through the pool PTF rate which increase transfer capability across existing or potential capacity zones.[1]

1) Section III.13.7.3.3.4

TRANSMISSION EXPANSION PJM

PJM awards incremental capacity transfer rights to market participants that fund transmission upgrades that increase the transmission import capability into a Locational Deliverability area.[1]

- PJM's incremental capacity transfer rights enable additional capacity external to a Locational Deliverability area to meet the unforced capacity obligation.
- The holder of incremental capacity transfer rights will receive the difference between the locational price adders for the sink and source Location Deliverability area in the Base Residual or Incremental auction.[2]

1) Attachment DD Section 2.35, 5.15 and 5.16
2) See attachment DD, Section 5.15 and 5.16

TRANSMISSION EXPANSION — Regulated

In the case of regulated transmission investments, the capacity market value of transmission upgrades is generally not explicitly allocated to those paying for the upgrade but is implicitly allocated to subset of those customers through changes in deliverability requirements.

- Thus in New England CTRs resulting from regulated transmission upgrades will be allocated to load serving entities in the import constrained region.[1]
- In PJM capacity transfer rights from regulated transmission facilities are allocated to all load serving entities within a Locational Deliverability area in proportion to their capacity obligation.[2]

1) Sections III. 13.7.3.3.4(d) and III. 13.7.3.3.2
2) Attachment DD, Section 5.15

C. Outage Performance

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OUTAGE PERFORMANCE

In energy only markets, generating resources must be available during shortage hours in order to recover their fixed costs and any return of or on investment, providing a strong incentive for them to be available and stay available during these hours.

- This is true even if the resource's output has been sold to a load serving entity under a forward contract as the generator will have to buy power at high prices to cover its contractual obligations.
- In 2011, NRG announced a nine digit earnings charge to cover the costs of buying power to cover forward contracts in ERCOT's energy only market due to higher outage rates than it accounted for in its forward contracting.

OUTAGE PERFORMANCE

The NRG example illustrates how forward contracting by power consumers will tend to ensure sufficient generation is available to meet load in an energy only market.

- There are no similar forces in a capacity market. The consequences to a generator of not being available are dramatically reduced.
- Load serving entities only need to buy the amount of capacity mandated by the ISO, regardless of what they expect to happen.

OUTAGE PERFORMANCE

Because spot energy prices are generally capped at relatively low levels, under capacity market systems generating and other resources typically recover only a small portion of their fixed costs and return of and on investment through energy market revenues during shortage conditions.

- Energy market revenues therefore do not provide capacity market resources with appropriate incentives to be available and online during reserve shortages when their availability is important to maintaining reliability

OUTAGE PERFORMANCE

Under a capacity market system, rules are necessary to ensure that capacity paid for being available actually is available and responds when it's output is needed to maintain reliability. PJM, NYISO and NEPOOL all initially adopted UCAP systems that rewarded capacity market generator resources for lower forced outage rates.

- UCAP = ICAP * (1 - Forced Outage Rate)
- Outage Rate = $\dfrac{\text{Equivalent Outage Hours}}{\text{Service Hours} + \text{Outage Hours}}$

OUTAGE PERFORMANCE — UCAP

There were variations from RTO to RTO in the time period over which the historical forced outage rate was calculated for the various capacity markets, but in all cases it was calculated over a 12-month historical period.

In NYISO the UCAP was fixed for the capability period, in PJM for the ICAP interval, and in NEPOOL for the next month.

OUTAGE PERFORMANCE UCAP

An important feature of UCAP systems was that the magnitude of the incentive to incur extraordinary costs to avoid outages was very low relative to the value of lost load and varied greatly between baseload and peaking units:

- For a baseload New York City unit with an annual UCAP payment of $100,000/MWh and 7,000 service + outage hours, an incremental outage hour cost the owner $14/MW of capacity market revenues.
- For a New York City peaking unit with 200 service + outage hours, an incremental outage hour cost the owner $500/MW of capacity market revenues.

OUTAGE PERFORMANCE NEPOOL FCM

Under NEPOOL's original forward capacity payment design, monthly capacity payments were reduced based on a capacity resource's availability during capacity events.

- Penalty= Annualized capacity payment * PF * [1- Shortage Event Availability Score]
- PF = .05 for shortage events of 1-5 hours, increase by .01 for each additional hour duration.
- Daily Penalty capped at 10%
- Monthly Payment capped at 20.833%

A shortage event is a period of 30 minutes or longer of system wide reserve shortage or specified operating procedures if called for generation adequacy in an import constrained zone for 30 minutes or more.[1]

1) ISO New England Tariff, ¶ Section III.13.7.1.1.1

OUTAGE PERFORMANCE — NEPOOL FCM

A resource's availability score was based on the resource's available megawatts during the hour of a shortage event,[1] plus the megawatt amount of capacity not available due to a planned outage approved in the annual maintenance scheduling process,[2] plus off-line capacity with a start up time of 30 minutes or less,[3] plus off-line capacity with a notification plus start-up time of 12 hours or less that was offered in the day-ahead market but not committed by the ISO.[4]

1) Section III.13.7.1.1.2
2) Section III.13.7.1.1.4 (b)
3) Section III 13.7.1.1.3(b)
4) Section III 13.7.1.1.3(c)

OUTAGE PERFORMANCE PJM RPM

Under its original RPM design, PJM similarly reduced payments to capacity sellers based on their availability during pre-defined peak hour periods.[1]

- PJM's summer peak hour period is hours ending 15 through 19, June through August, excluding weekends and holidays.
- PJM's winter peak hour period is hours ending 8 through hour ending 9 and hour ending 19 through hour ending 20, during January and February, excluding weekends and holidays.

These rules were more focused than the original UCAP design and incented better performance by generation.

1) Attachment DD, Sections 10(a) and (b).

OUTAGE PERFORMANCE PJM RPM

Outage hours included those full or partial outage hours when the unit was not available due to an outage and;

- Would have been in merit or called upon operating reserves,
- The non-availability was not due to non-availability of gas.

Units were not penalized for not having been committed day-ahead, regardless of the length of their start-up and notification times.[1]

1) Attachment DD, Sections 10(c)-(g)

OUTAGE PERFORMANCE Maintenance

In addition to rules relating to forced outages, power pool reserve requirement systems and contemporary capacity markets have rules governing the scheduling of planned maintenance outages. These rules

- Penalize the scheduling of planned outages during peak seasons;
- Require coordination of generation (as well as transmission) outages during other periods.

D. Resource Availability and Limited Energy Resources

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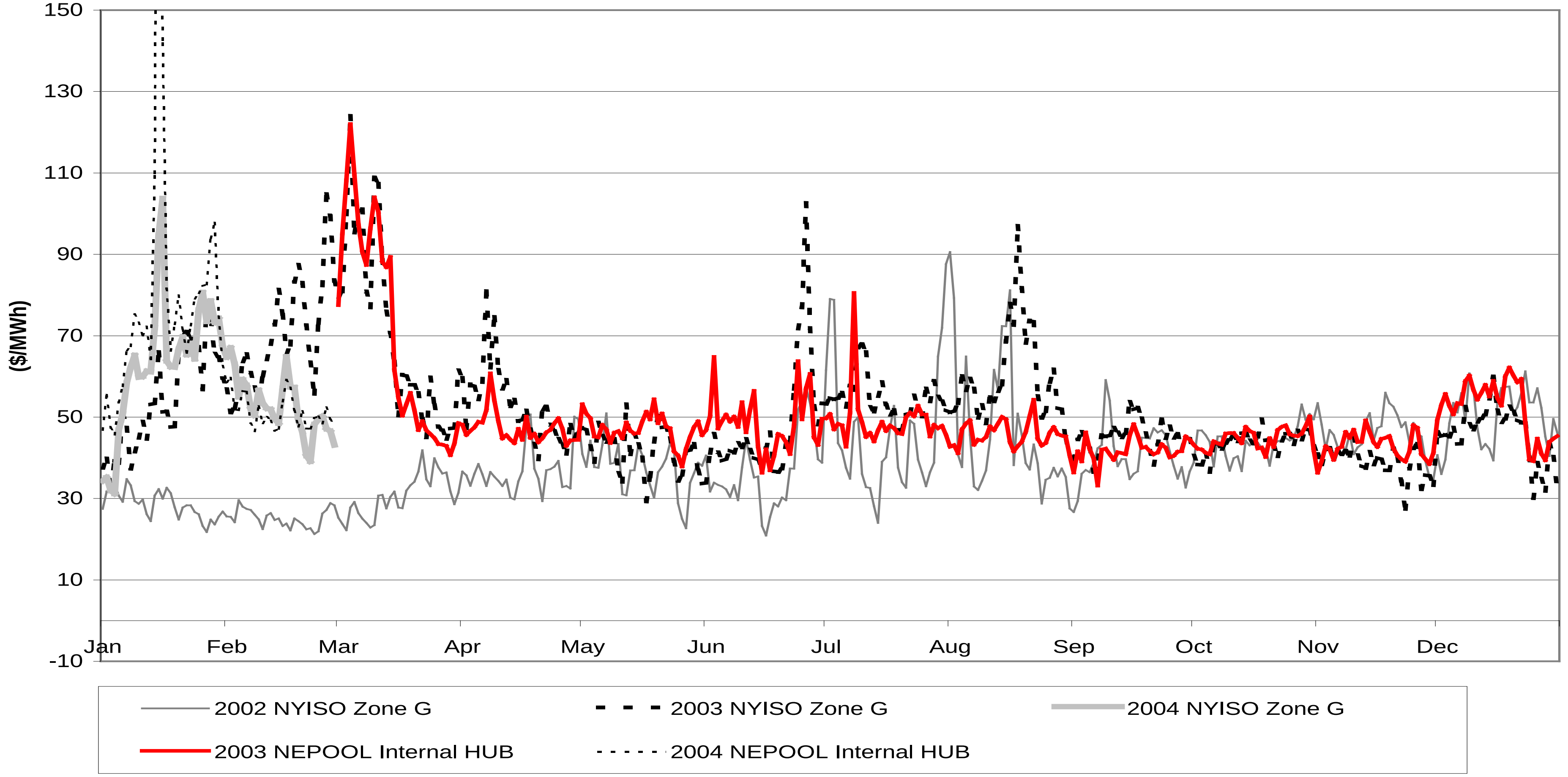
OUTAGE PERFORMANCE — Overview

Another problem with generator availability in capacity market systems is that reliability does not depend solely on generator capacity and forced outage rates. Other important characteristics affecting the energy output of capacity resources during stressed system conditions are:

- Fuel availability.
- Energy limits.
- Startup costs and conditions.
- Availability constraints.
- Intermittency.

NYISO Hudson Valley (Zone G) and NEPOOL Hub 2002-2004 Daily Average DAM Prices



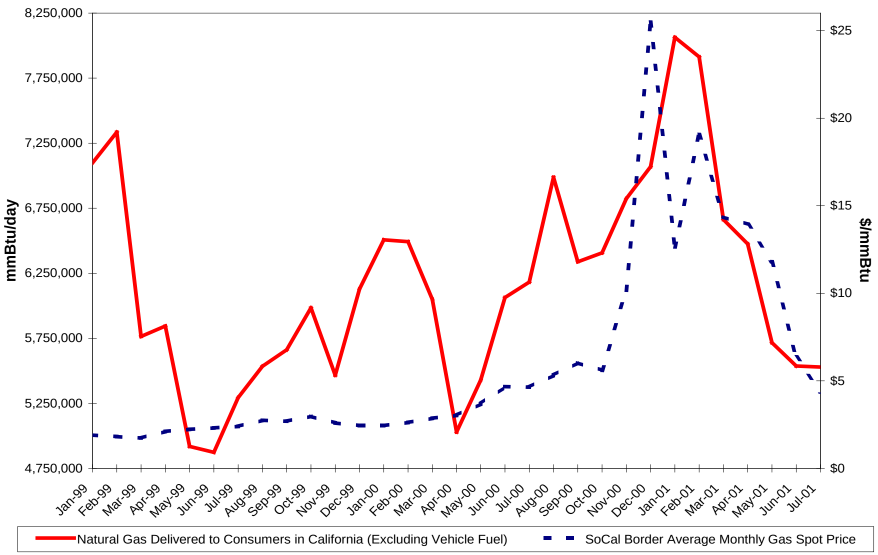
GENERATOR AVAILABILITY Fuel

While U.S. transmission systems are increasingly summer peaking, many of the more severe generation capacity caused reliability crises over the past two decades have arisen during the winter months:

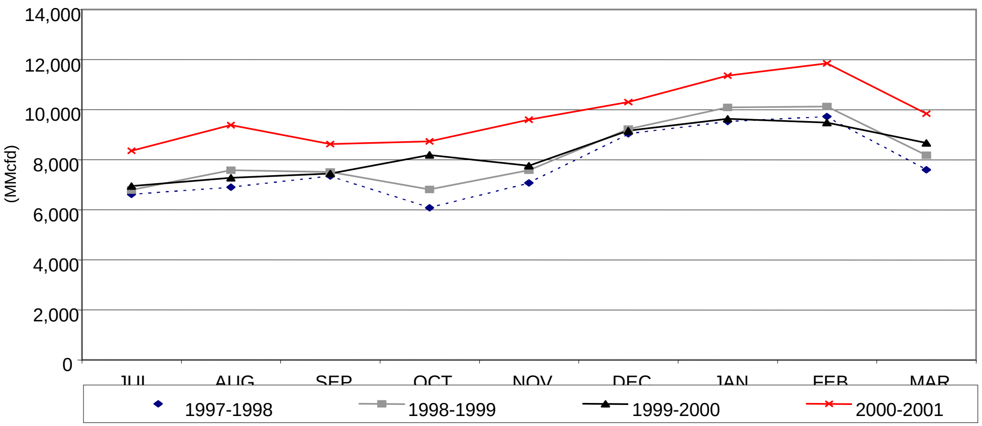
- PJM -- 1994
- California -- 2000-2001
- ERCOT -- 2003
- NEPOOL – 2004
- ERCOT – 2011
- PJM -2014

An important contributor to these winter reliability crises has been the cost and availability of gas-fired generation during periods of high demand both for electricity and gas for space heating.

California Gas Demand and Prices



Average Daily Natural Gas Delivered to Consumers in CA, OR, WA, AZ, NV and NM (Excluding Vehicle Fuel)



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GENERATOR AVAILABILITY Fuel

In California during the winter of 2000-2001, unusually high demand for gas-fired generation both in California and the west in general (driven by low hydro conditions and nuclear plant outages) combined with cold weather to produce very high gas prices.

- Most of the load shedding that occurred in California over 2000-2001 took place during the winter.
- It was simply was too expensive in terms of gas and NOx allowance costs to keep high heat rate generation on-line to provide reserves during peak hours.

GENERATOR AVAILABILITY — Fuel

Aside from the impact of high gas prices on electric prices when gas-fired generation is on the margin, winter gas supply constraints can impact reliability in a number of ways:

- Localized gas pressure limits on generator output;
- Curtailment of non-firm gas sales under traditional gas LDC curtailment rules;
- Curtailment of non-firm gas transportation by LDCs in unbundled gas markets;
- Withdrawal of gas-fired generation from the power market due to market risk or inability to reflect gas costs in offer prices
- Lack of interstate pipeline capacity to meet both space heating and power generation demand.

GENERATOR AVAILABILITY — Fuel

Outages of the gas transmission system can also impact electric system reliability as was seen in the Southwest during February 2011.

GENERATOR AVAILABILITY Fuel

In very thin, volatile gas markets:

- Buying gas before locking in the electricity price can be risky; the generator may have to sell the gas for a large loss if its supply offer fails to clear in the power market.
- Selling power before locking in gas costs can be risky as the cost of gas may turn out to be far higher than can be recovered in the electricity price.
- The UCAP penalty to a baseload unit for not being available during the winter peak would be very small relative to gas and power price risk.

OUTAGE PERFORMANCE — NEPOOL FCM

The original FCM design in New England did not allow for "economic" outages, however, this provision was later deleted from the tariff.

- The ISO New England Internal Market Monitor's 2011 and 2012 Annual Markets Reports, noted repeated problems over the 2010-2012 period with gas fired resources that declared themselves unavailable in real-time because gas price levels made their operation uneconomic.[1]
- These performance problems with gas fired generation led ISO New England to assert obligations for capacity market suppliers to be available (Docket EL13-66) and the development of the "Pay for Performance" capacity market design.

1) ISO New England, Internal Market Monitor, 2011 Annual Markets Report, May 15, 2012, p. 74; 2012 Annual Markets Report May 15, 2013, Section 2.1.3.3 pp 19-26.

OUTAGE PERFORMANCE

These performance problems with gas fired generation in New England in part reflected the imperfect performance incentives provided by a capacity market. But they were also in part due to:

- the late timing of the ISO New England day-ahead market;
- underbidding by load serving entities that caused generators needed for reliability to not get day-ahead market schedules to cover gas purchases; and
- ISO New England energy market rules that did not allow in day changes in offer prices to reflect intra-day gas prices.

The performance issues with the availability of gas fired generation in New England during diminished during 2013 and 2014 after the day-ahead market was moved earlier in the day, shortage prices were increased, and bidding flexibility was provided, allowing generators to offer supply based on the cost of gas. [1]

1. See ISO New England, Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, pp, 21, 31; ISO New England, Internal Market Monitor, 2013 Annual Markets Report, May 6, 2014, pp, 47-51

OUTAGE PERFORMANCE NEPOOL

These performance problems with gas fired generation led ISO New England to develop a new “Pay for Performance” capacity market design with the first auction cleared under the new design in February 2015 (FCA 9) for the 2018-2019 delivery year.

As in ISO New England, PJM has had problems with the performance of gas fired generation on cold winter days when gas prices are high.

- Lack of generator availability and high outage rates during the winter of 2013-2014 during the "Polar Vortex" events led to PJM developing a new capacity product.
- As in ISO New England, part of the performance problem in PJM had likely been a result of the energy market design which does not allow offer price increases during the operating day, making it impossible for gas fired generators to reflect intra-day gas prices in their offers, rules that prevent generators from varying their market based minimum load and start-up cost offers from day to day to reflect gas prices, and "cost based" offer price rules that cause offer prices to lag actual gas prices.

OUTAGE PERFORMANCE PJM RPM

Under the original RPM design, outage hours in PJM did not include "outages outside management control," which included outages due to "lack of fuel."

- The 2012 State of the Market Report stated that "lack of fuel" accounted for 4.6% of all forced outages in PJM during 2012, [1] This fell to 1.1% in 2013 and .5% in 2014. [2]
- The State of the Market Report has recommended for several years that these outages no longer be treated as "outside management control." [3]

1) Monitoring Analytics, 2012 State of the Market Report for PJM March 14, 2013, p. 164 (Table 4-31)
2) Monitoring Analytics 2013 State of the market report, March 13, 2014 p. 192 (Table 5-31); 2014 State of the market Report for PJM, March 12, 2015, p. 212 (Table 5-31)
3) See also Monitoring Analytics, 2011 State of the Market Report for PJM March 15, 2012, p. 116

GENERATOR AVAILABILITY Fuel

The reliability analyses from which capacity requirements are derived are probabilistic assessments of available generation, transmission and load.

- Generation forced outages are treated as independent events in assessing loss of load probabilities.
- These probabilities will not be accurate for fuel-driven outages because these outages will be highly correlated across gas-fired generation as well as correlated with high electric load.

GENERATOR AVAILABILITY Fuel

Electric system reliability requires some kind of incentive for market participants to make the investments required to sustain electric power output during periods of high space heating demand when the gas system will be constrained.

- Dual fuel generating capability.
- Consumption area gas storage, including LNG.
- New gas transmission capacity.

If these incentives are not provided by energy market prices, they need to be provided by the capacity market. The capacity market will need to provide even stronger performance incentives if the energy market design does not allow gas fired generators to recover their incremental fuel costs, as has been the case in PJM and ISO New England.

GENERATOR AVAILABILITY — Fuel

The lowest cost way to address these gas supply reliability issues has historically been to maintain dual-fueled generating capability.

- Historically, both NEPOOL and New York have had substantial utility-owned dual fueled generation that assured electric system reliability during winter peak conditions.
- PJM on the other hand, had so much coal generation that a few dual fueled peakers were all that was needed to maintain winter reliability.

GENERATOR AVAILABILITY Fuel

Maintenance of this historic dual fueled capability is not assured in deregulated markets unless the market design provides appropriate incentives either in the energy or capacity market.

- New gas-fired generation in New York, New England and PJM initially often lacked dual fuel capability.
- In some cases, existing dual fuel capable generation has been or will be retired and replaced with gas-fired generation.
- Moreover, dual fuel capability has to be maintained over time by maintaining necessary permits, fuel stocks and equipment.

Another factor complicating reliance on dual fuel capability to maintain winter reliability is that environmental regulations may increasingly limit the ability of gas fired generation to switch to oil fuel.

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	November 1993 – April 1994		November 2000 – April 2001	
	Total MW	**Oil MW**	**Total MW**	**Oil MW**
	Northern California			
Potrero 3	529,329	20,580	536,859	0
Hunters Point	629,532	137,329	359,412	0
Pittsburg	4,420,365	251,551	5,402,515	0
Contra Costa	2,111,946	121,611	1,853,595	0
Moss Landing	5,061,748	318,929	3,876,883	0
Morrow Bay	1,774,232	112,484	2,552,311	0
Total	**14,527,152**	**962,484**	**14,581,575**	**0**
	Southern California			
Encina	1,261,524	610,662	2,488,493	52,831

120

GENERATOR AVAILABILITY Fuel

California’s electric generation used to have substantial fuel switching capability.

- During the drought of 1994 there was substantial fuel switching by California electric generation that did not occur in 2000-2001.
- In 2000-2001, total generation was similar to or higher than in 1993-1994 at the plants formerly having fuel switching capability. Without fuel switching, gas fired generation was notably higher at these plants in 2000-2001.
- The lack of fuel switching by electric generation contributed to a much tighter supply-demand balance for gas in 2000-2001 than in 1993-1994.

	November 1993 – April 1994		November 2000 – April 2001	
	Total MW	**Oil MW**	**Total MW**	**Oil MW**
Northern California				
Potrero 3	529,329	20,580	536,859	0
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Southern California				
Encina	1,261,524	610,662	2,488,493	52,831

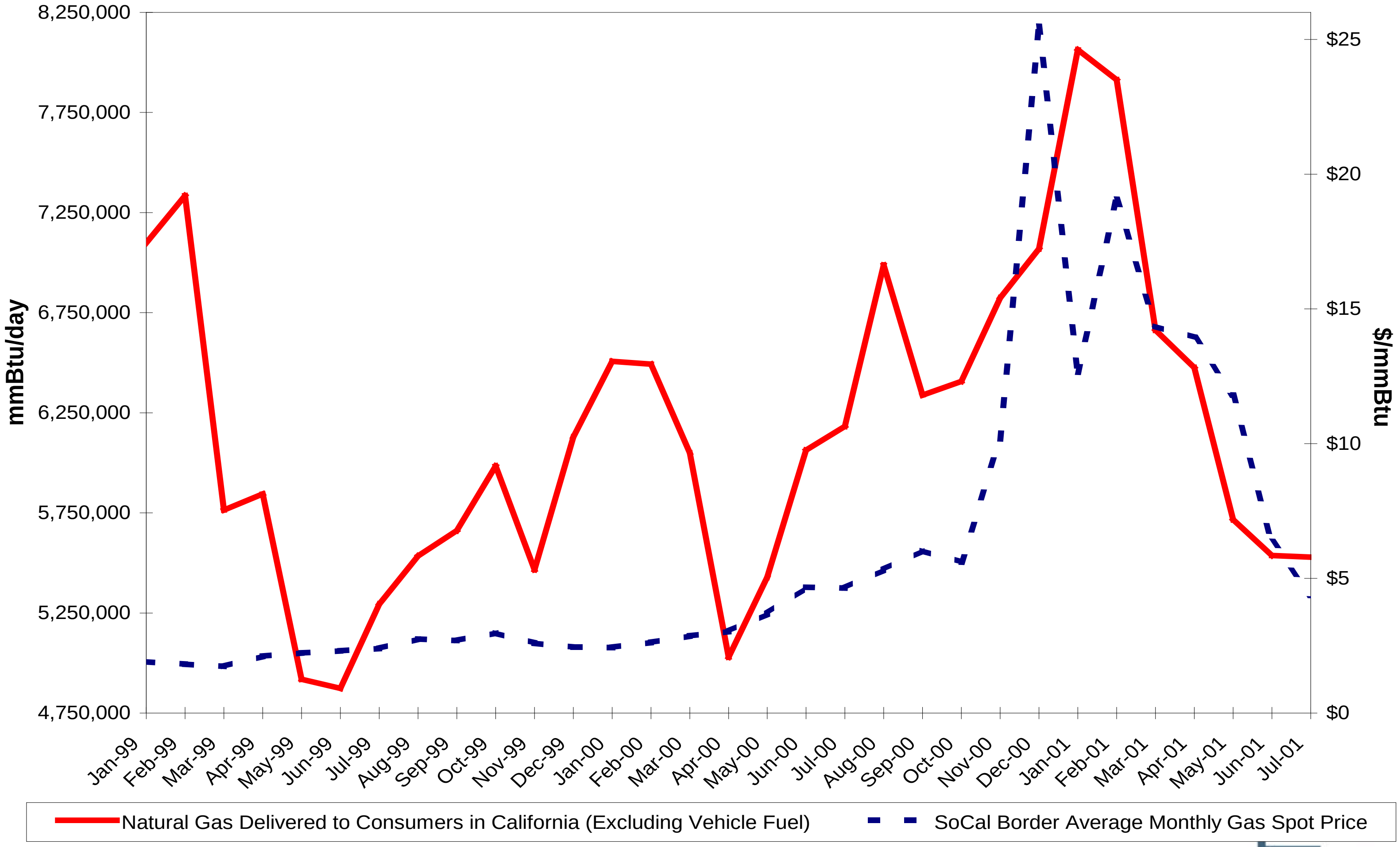
GENERATOR AVAILABILITY Fuel Switching

Part of the change in fuel switching behavior in California between 1994 and 2001 was due to changing environmental limits and unit capabilities.

- Part of the change in fuel switching behavior was also due to changes in gas pricing.
- Electric generation in San Diego did switch fuels in 2000-2001, but switched far less than in 1994, despite far higher generation output.

The impact of EPA regulations on the fuel switching ability of gas fired generation will be an important factor impacting electric system reliability in coming years.

California Gas Demand and Prices



GENERATOR AVAILABILITY Fuel Switching

In 1994, SoCalGas consumers could buy all they wanted at the regulated price and when there was not enough supply available at the regulated price, some customers, including dual-fuel customers able to fuel switch, were interrupted by the gas distribution company.

In 2000-2001, non-core gas consumers could buy all the gas they wanted at the market-clearing price. As long as there was enough gas at the market-clearing price, non-core customers were not interrupted, but the gas price paid by non-core customers that continued to burn gas was extremely high.

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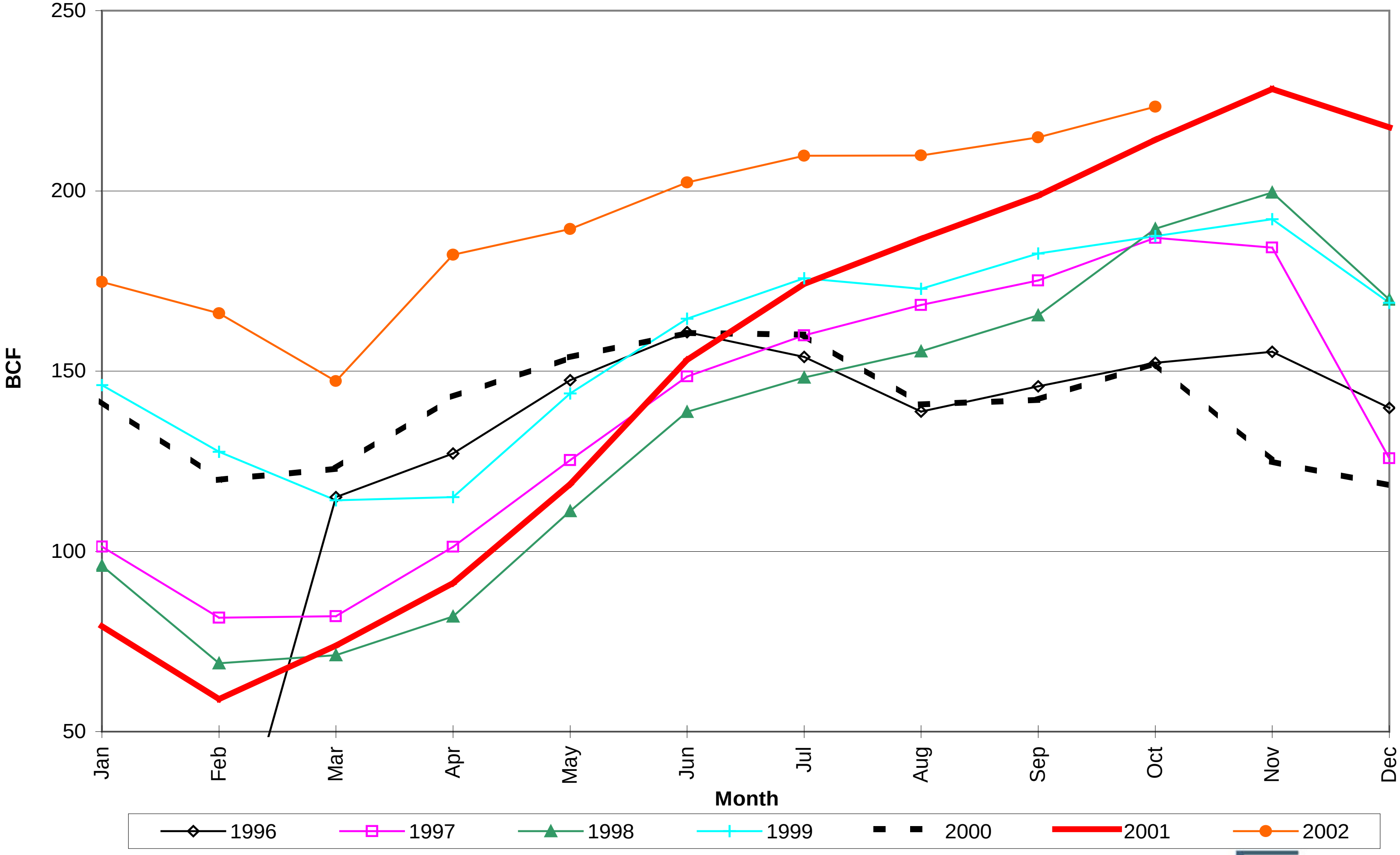
GENERATOR AVAILABILITY Fuel Switching

Even with dual fuel capability, it is necessary that capacity resources that are counted on to be available during the winter peak have enough fuel stocks to operate through a sustained winter peak period.

- The 1994 PJM reliability crisis was magnified by frozen rivers and icy roads which slowed or precluded replenishment of oil stocks.
- The 2003 ERCOT reliability crisis was magnified by the accompanying ice storm which made resupply virtually impossible and by the uncertain duration of the cold spell.

Maintaining large fuel stocks requires a capital investment that will only yield a return under very occasional conditions but these stocks may be necessary to maintain current reliability levels (one day in ten years).

Working Natural Gas in Underground Storage at End of the Month, California (Bcf)



Data from Table 39. Source: EIA Natural Gas Monthly, Table 14. Before 1998, Table 13.

GENERATOR AVAILABILITY Fuel

Another important reliability issue for gas-fired generation is the incentive of power market participants to put gas in storage to meet load during the winter when the gas pipeline system is constrained.

- Part of California's reliability problem during the winter of 2000-2001 arose because non-core gas customers held one-third of SoCalGas's storage capacity but entered the winter with no gas in storage.
- New England does not have consumption area underground gas storage but LNG delivery capacity can play a similar role. It is desirable for gas-fired generation lacking dual fuel capability to have access to LNG.

GENERATOR AVAILABILITY Fuel

Capacity market systems do not provide an incentive for gas fired generation to make any investment to receive gas from LNG storage under stressed system conditions. Moreover, LNG prices have decoupled from spot gas prices, including those used for mitigation.

GENERATOR AVAILABILITY Energy Limits

A variety of generating units are subject to limits on their energy output over the day, year or other period. These limits can have a variety of sources:

- Environmental requirements.
- Water flow and pondage (hydro).

Energy-limited units are useful in providing reserves and meeting peak load but too much capacity supplied by energy-limited resources could lead to reliability problems.

GENERATOR AVAILABILITY — Energy Limits

Some resources also have intra-day energy limits. The NYISO[1] and ISO-NE[2] UCAP systems originally treated pumped storage units able to supply power for four consecutive hours a day as capacity resources.

- Pumped storage in its current proportions is very valuable in providing reserves and meeting peak load.
- Technological change could result in a large increase in the supply of short duration energy in response to high capacity prices, but such a large supply of short duration energy might have little value.

1) Service Tariff Section 5.12.11.(c)

2) ISO New England Installed Capacity Manual Section D1.1.5 and Attachment D pp. DA-8 and DA-9

GENERATOR AVAILABILITY Startup

Generating units are permitted under most capacity market systems to submit unit startup times that exceed 24 hours.

- These long startup times reduce manning costs as rarely used generation can be left unmanned during low demand periods.
- This capacity is not available, however, when weather conditions change rapidly (e.g., PJM winter 1993-1994; ERCOT, February 24-25, 2003; New York and NEPOOL, May 7-8, 2000).

Units dependent on high energy market prices during shortage conditions for revenues would take steps to ensure their availability during such surprises. There is no need for the unit owner to do so under an UCAP availability system. Units not available due to long start-up times suffer no UCAP penalty.

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GENERATOR AVAILABILITY NEPOOL FCM

In NE POOL's original forward capacity market design, resources with notification plus start up times greater than 12 hours incur penalties if they are not available (i.e. already on line) during shortage events.

- Units with notification plus start-up times of 12 hours or less were treated as available since they were not available because the ISO did not commit them.

FTI

GENERATOR AVAILABILITY Intermittent Resources

Resources such as solar and wind generation and run-of river hydro give rise to additional issues in assessing reliability.

- Treating reductions in wind output like forced outages does not accurately account for the reliability impact of these output reductions.
- Unlike the forced outages of thermal units, the availability of output from wind generation is likely to be highly correlated across units and may also be inversely correlated with demand (low wind output and high A/C load).

GENERATOR AVAILABILITY Intermittent Resources

New York currently values wind and solar resource capacity based on an average capacity factor during hours beginning 14 through 18 during the months of June, July and August, and hours beginning 16 through 20 during the months of December through January. [1]

- New York measures run of river capacity based on the average net energy provided in the 20 highest New York Central area real-time load hours in each of the prior 5 years, calculated separately for winter and summer periods. [2]

1. New York ISO Installed Capacity Manual, page 4-23.
2. New York ISO Installed Capacity Manual, page 4-22

GENERATOR AVAILABILTY Intermittent Resources

PJM has used a 13% default capacity factor for wind and a 38% default capacity factor for solar in the 2014/2015 through 2017-2018 RPM auctions. [1]

1. PJM Generation and Transmission Interconnection Process Manual 14a p. 94.

GENERATOR AVAILABILITY Intermittent Resources

ISO- New England’s tariff provides for the intermittent resource to determine its qualified capacity subject to ISO- New England assessing whether the data provided “reasonably supports the claimed summer and winter qualified capacity.” [1]

> The summer/winter qualified capacity is the median output during the past 5 summer/winter periods. [2]

Intermittent resources are not subject to availability penalties under ISO-New England's FCM design, but are subject to the peak energy rent deduction.[3]

1. Section III.13.1.1.2.4.e
2. Section III13.1.2.2.2.1-2
3. Section III. 13.7.2.7.3

GENERATOR AVAILABILITY Intermittent Resources

It is also difficult for market participants and regulators to accurately assess the contributions of intermittent resources to reliability in an energy only market.

- Market participants in an energy only market may keep too little thermal generation in operation because they overestimate the energy output of intermittent resources under stressed system conditions.
- In a capacity market system, however, intermittent resources will potentially earn capacity payments based on their assumed performance rather than their actual performance.
- As wind generation becomes more significant in eastern capacity markets, it will be more important for capacity markets to accurately account for its contribution to reliability.

E. Demand Response

DEMAND RESPONSE

Demand response is an important part of capacity market design.

- Well designed demand response programs allow power consumers that are able to reduce their load under high load conditions to avoid paying capacity charges for capacity they do not use.

DEMAND RESPONSE

Capacity market systems in PJM, New York, and ISO New England allow demand response resources having the ability to reduce load and making the commitment to do so when needed to substitute for generating capacity.

- SCR (New York ISO)
- Energy Efficiency, Interruptible Load for Reliability (ILR) until 2012-2013 RPM year, PJM demand response, FRR demand response (PJM)
- Real-time demand response, real-time emergency generation, on-peak demand response, seasonal peak demand response (ISO-New England)

DEMAND RESPONSE New England

The amount of demand response clearing in New England forward capacity market auctions has been large and rising, despite low capacity market prices.

Auction	Megawatts	Operation Year
FCA 1	2279	2010-2011
FCA 2	2778	2011-2012
FCA 3	2868	2012-2013
FCA 4	3261	2013-2014
FCA 5	3468	2014-2015
FCA 6	3628	2015-2016
FCA 7	2748	2016-2017
FCA 8	3041	2017-2018
FCA 9	2803	2018-2019

ISO New England 2010 Annual Markets Report, Table 4-6, ISO New England. 2014 Annual Markets Report, Table 3-10. FCA 9 Auction Results, Summary.

DEMAND RESPONSE PJM

Demand Response Resources (MW) in PJM 2007 - 2018

	PJM Demand Response	Energy Efficiency	ILR	Total
2007-2008	127.6		1636.3	1763.9
2008-2009	536.2		3608.1	4144.3
2009-2010	892.9		6481.5	7374.4
2010-2011	939		8236.4	9175.4
2011-2012	1364.9		9032.6	10397.5
2012-2013	7047.2	568.9		7616.1
2013-2014	9281.9	679.4		9961.3
2014-2015	14118.4	822.1		14940.5
2015-2016	14832.8	922.5		15755.3
2016-2017	12408.1	1117.3		13525.4
2017-2018	10974.8	1388.9		12363.7

2014 PJM State of the Market Report, Table 5-8, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec5.pdf

DEMAND RESPONSE New York

Demand Response (SCR) has had a growing presence in New York's capacity market but is concentrated in Upstate New York where capacity prices are relatively low.

NYISO July Supplemental Capacity Resources (MW)
2008 - 2015

Year	Zone J	Zone K	ROS	LHV	NYCA
2008	463.1	166.4	1070.9	540.6	1700.4
2009	456.3	163.8	1301.9	576.7	1922
2010	481.9	158.3	1438.3	620.3	2078.5
2011	420.3	136	1337	535.4	1893.3
2012	384.3	85.3	1179	459.3	1648.6
2013	341.5	77.8	646.9	392.4	1066.2
2014	312.3	59.2	624.7	371.5	996.2
2015	380.7	66.1	787.2	459	1234

Source: NYISO Monthly SCR Reports
http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp
Rest of State Total includes LHV.

DEMAND RESPONSE Issues

Some of the key issues in accounting for demand response resources within capacity market designs are:

- Potentially limited frequency of demand response commitment to reduce load;
- Inability of individual demand resources to commit to reduce load during hours when they are not consuming power;
- Time lags and inflexibilities in activating demand response resources, combined with inability to dispatch demand response resources up and down as the amount needed varies.
- Measurement of baselines.

DEMAND RESPONSE Activations

Most capacity market demand response participation rules require that demand response resources providing capacity can only be interrupted a limited number of times and hours per year.

- New York- 4 hours per day[1]
- PJM- 10 times a year for 6 hours (pre capacity performance product)
- ISO New England- condition based

This is different from the treatment of most generation, which is exposed to penalties if not available when needed.

1. Service Tariff Section 5.12.11(a)

Limits on demand response activations such as those in PJM have the potential to become more and more problematic as demand responses displaces more and more generation in the capacity market as the displaced generation will have been needed during more and more hours.

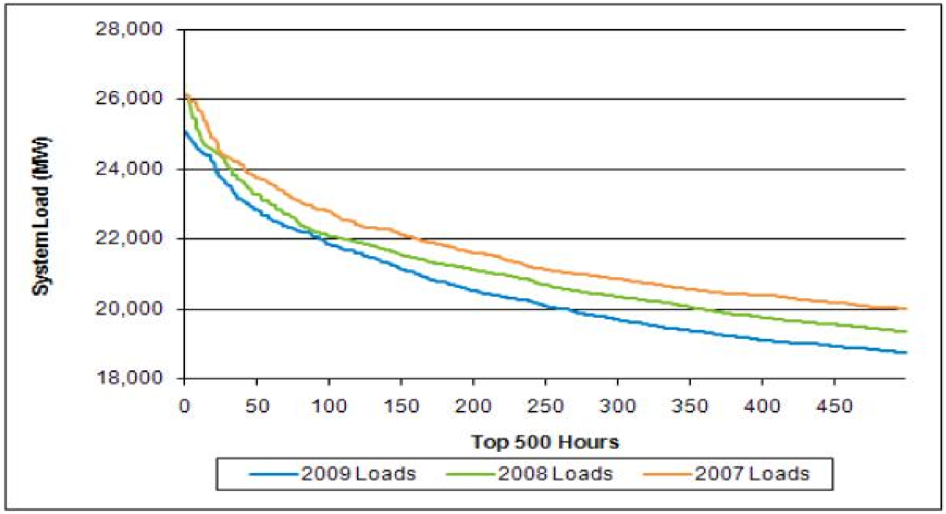

Figure 4-4: Load-duration curves for the 500 highest-demand hours in 2007, 2008, and 2009.

Note: From the spreadsheets *2007_smd_hourly.xls, 2008_smd_hourly.xls, and 2009_smd_hourly.xls*, available at http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html.

Reproduction from ISO New England, 2009 Annual Market Report.

DEMAND RESPONSE — Time Lags

The current design of most capacity market demand response programs is not well suited to meeting electric system needs and tends to result in too much demand response being activated for too long. These design features include:

- Rules that require that demand response resources be activated an hour or more before they are needed;
- A general lack of dispatchability by demand response resources;
- Rules that given operators a single one time option to activate demand response each day.

DEMAND RESPONSE — Baselines

ISO capacity requirements are determined taking into account the fact that not all peak loads are coincident across consumers.

- Hence: ∑ Individual Consumer Peak > ISO peak
- Giving consumers capacity market credits based on their load reductions relative to their individual load peaks would overstate the load reduction.
- Conversely, only giving demand response resources credit for the amount of load reduction they can deliver year round would understate the value of the demand response.
- Getting it right is complex

DEMAND RESPONSE PJM

To address concerns that PJM would not be able to maintain reliability if the amount of demand response available only for a limited number of hours per year became too large a proportion of capacity, PJM introduced three categories of demand response in the 2014-2015 auction:

	2014-2015	2015-2016	2016-2017	2017-2018
Limited Demand Response	12165.9	9247.2	9849.5	2322.1
Extended Summer	1441	5202.3	2470	7163.3
Annual	511.5	383.3	88.6	1489.4

Source: PJM Base Residual Auction results
http://www.pjm.com/markets-and-operations/rpm.aspx

DEMAND RESPONSE PJM

In all four years, the annual and extended summer demand response cleared at the same price as generation capacity in almost every region.

- The limited demand response cleared at a price about $4000 per megawatt year lower than generation in most PJM regions in 2014-2015 and 2017-2018 and about $6000 per megawatt year lower for 2015-2016.
- There was no differential for limited demand response for 2016-2017 except in the ATSI region.

DEMAND RESPONSE New England

There are some concerns regarding demand response performance arising from the New England capacity market design:

- Until recently much more than the target level of generating capacity has remained in operation, reducing the likelihood of demand response being called upon.
- Because offers at the price floor were prorated, there was an incentive to submit offers for more demand response then would be able to perform

Both factors created the possibility that the supply of demand response would drop sharply if and when the supply demand balance in NEPOOL tightens, but the decline has been only a few hundred megawatts to date.

F. Imports and Exports

IMPORTS AND EXPORTS

Capacity markets also require rules to account for imports and exports of capacity. The key issues are:

- External capacity vs. external tie benefit
- Recall rules for exports during shortages
- Scheduling rules for external capacity
- Offer prices and mitigation for external capacity
- Analyzing reliability of external resources

IMPORTS AND EXPORTS Tie Benefit

One complex issue regarding external resources is that power pools and now ISOs typically account for their ability to import energy from adjacent pools on a probabilistic basis when setting the reserve margin.

- Contracting for some of that external capacity does not raise reliability as much as additional internal capacity and rate payers end up paying for the reliability value of external resources that they would otherwise get for free
- This is one reason that most of the pools and ISOs limit the transfer capability available to support capacity imports.

IMPORTS AND EXPORTS — Recall

All ISOs with capacity markets have rules allowing the ISO to recall energy exports during shortage conditions unless those exports are supported by the output of capacity resources of the sink control area.[1]

- Such rules are essential to assure that consumers receive the reliability benefit of the capacity resources whose going forward costs they are paying.
- Conversely, each ISO has rules assuring that exports supported by the output of capacity resources dedicated to serving load in another control area will not be subject to recall, even during shortage conditions.

1. ISO New England, Market Rule 1, Section III.1.11.4, New York ISO Services Tariff Section 5.12.10, PJM Operating Agreement, Schedule 1, Sections 1.10.6 and 1.11.3A

IMPORTS AND EXPORTS Scheduling

Another issue is what is equivalent for an external resource to the must offer obligation of internal resources.

- The external resource must comply with both the NERC interchange scheduling rules and those of the host balancing authority area, so generally cannot be dispatched in real-time as can an internal resource.
- While it might seem comparable to require external capacity resources to offer imports on a cost basis, any market participant can offer import supply from adjacent RTO markets during normal market conditions.
- The capacity market obligation of external supplier is significant only when the balancing authority area in which they are located is recalling experts not supported by the output of capacity resources.

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- During periods when exports are being recalled by the source control area the price of energy should be at or above the price cap.

IMPORTS — New England

Imports have been an important source of capacity for New England under the forward capacity market. Much of this capacity is ultimately sourced from Hydro Quebec, New Brunswick, or New York.

Import Capacity Megawatts
FCA Auctions

	Delivery Year	Import Capacity MW
FCA 1	2010/2011	934
FCA 2	2011/2012	2298
FCA 3	2012/2013	1900
FCA 4	2013/2014	1993
FCA 5	2014/2015	2011
FCA 6	2015/2016	1924
FCA 7	2016/2017	1830
FCA 8	2017/2018	1237
FCA 9	2018/2019	1449

Source: ISO-NE FCA Result Reports
http://www.iso-ne.com/markets-operations/markets/forward-capacity-market

IMPORTS AND EXPORTS

Limits on imports from both New York and New Brunswick bound in FCA 9, so imports over these interfaces cleared at a lower price than rest-of-pool capacity.

$/KW Month

Rest of Pool	**New York AC**	**New Brunswick**
9.551	7.967	3.940

IMPORTS PJM

PJM Capacity Market Imports rose to over 7000 megawatts in the auction for 2016-2017, then fell substantially in the 2017-2018 auction.

PJM Cleared Imports (UCAP MW) 2007 - 2018

	Cleared Imports (UCAP MW)
2007-2008	1,620.80
2008-2009	1,625.80
2009-2010	1,669.10
2010-2011	1,726.10
2011-2012	4,756.10
2012-2013	2,335.50
2013-2014	3,254.00
2014-2015	3,016.50
2015-2016	3,935.30
2016-2017	7,482.70
2017-2018	4,525.50

Source: PJM 2014 State of the Market Report, Table 5-9
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec5.pdf

IMPORTS AND EXPORTS PJM

Limits on imports were enforced in the PJM 2017-2018 RPM auction but the constraints did not bind.

- Capacity Performance Product resources must meet the criteria for a capacity import limit (CIL) exception: they must be dispatchable via a pseudo tie, they must comply with PJM “must offer” rules, and must be deliverable with firm transmission.

IMPORTS — New York

The New York ISO has also had a moderate level of capacity imports.

NYISO Imports (UCAP MW)
April 2013 – August 2015

Month	Year	Imports
April	2013	1089.9
May	2013	1089.9
June	2013	1089.9
July	2013	1089.9
August	2013	1089.9
September	2013	1089.9
October	2013	1089.9
November	2013	1089.9
December	2013	665
January	2014	331.4
February	2014	357.8
March	2014	664.7
April	2014	1089.9
May	2014	1197.8
June	2014	1355.6
July	2014	1376.7
August	2014	1465.1
September	2014	1471.9
October	2014	1485.3
November	2014	1369.6
December	2014	538.8
January	2015	854.9
February	2015	673.4
March	2015	1187.6
April	2015	1188.1
May	2015	1415.9
June	2015	1102.8
July	2015	1092.2
August	2015	1129

http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

G. Capacity Markets and Retail Access

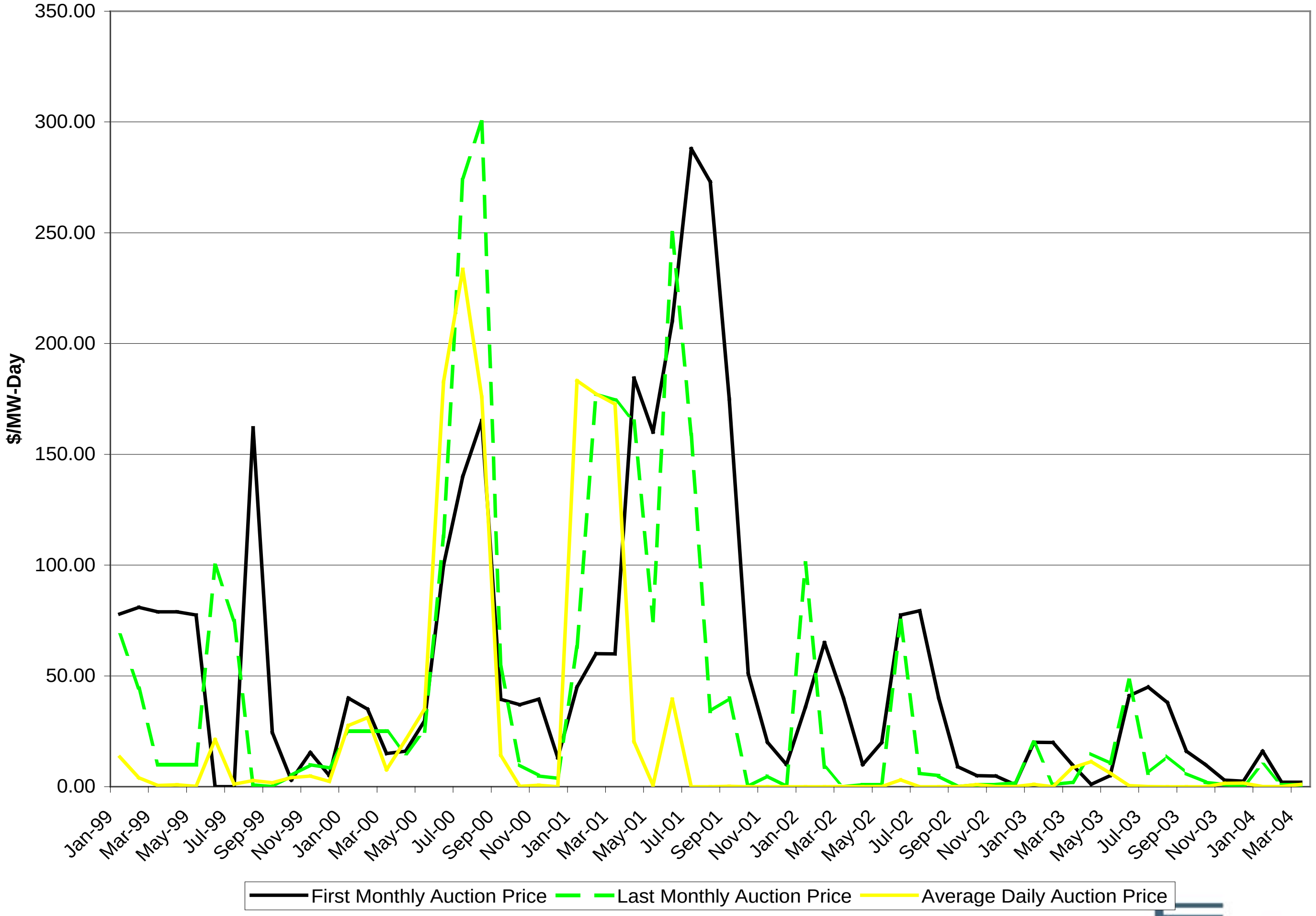
RETAIL ACCESS

Retail access programs typically have features that tend to undermine capacity markets.

- Both capacity and energy-only markets will work best if load serving entities enter into long-term contracts for the energy and capacity needed to serve customer load.
- Load serving entities in retail access areas generally lack either long-term consumer contracts or a long-term obligation to serve.
- Retail access programs like also create a risk reward structure that makes it uneconomic for the load serving entities to enter into long-term capacity or energy contracts to cover short-term retail load contracts.

It appears that load serving entities in retail access states have rarely entered into long-term contracts with potential generation entrants, and they have been particularly unlikely to enter into long-term capacity market contracts.

PJM UCAP Market Prices



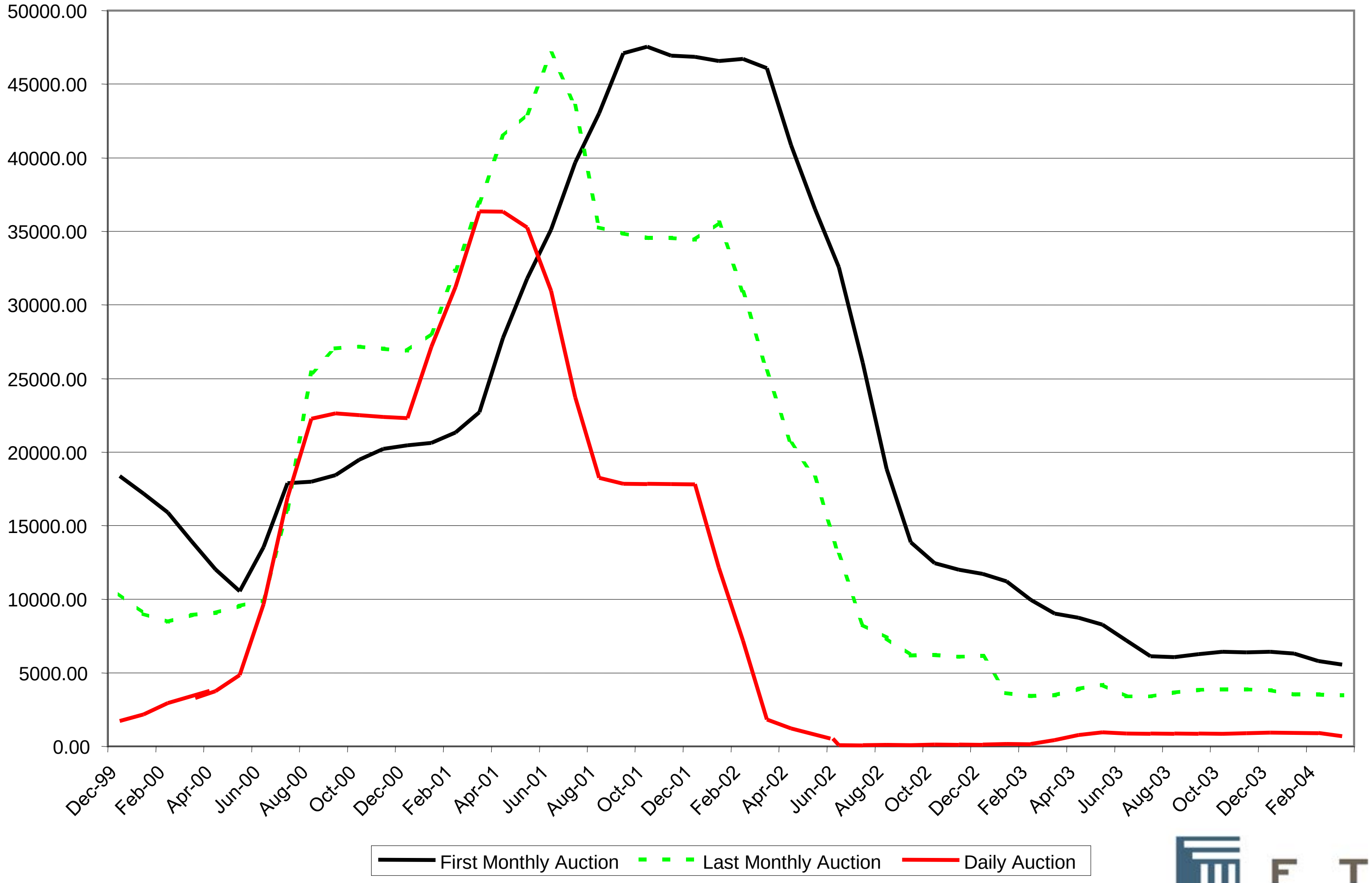
RETAIL ACCESS

In an environment with retail choice, capacity markets must incorporate mechanisms to accommodate load switching. In PJM, load serving entities initially were not required to procure UCAP to cover the loads they served until the day before the operating day.

- There was no central mechanism to credit load serving entities that lost loads or to charge load serving entities that gained load from day to day.
- If load serving entities needed to purchase additional UCAP or dispose of excess UCAP due to load shifts, they could do so in the daily auction.
- If an load serving entity was short of capacity due to a load shift, it was assessed a deficiency penalty, prorated on a daily basis.

This led to very volatile and on average very low capacity prices in the daily market.

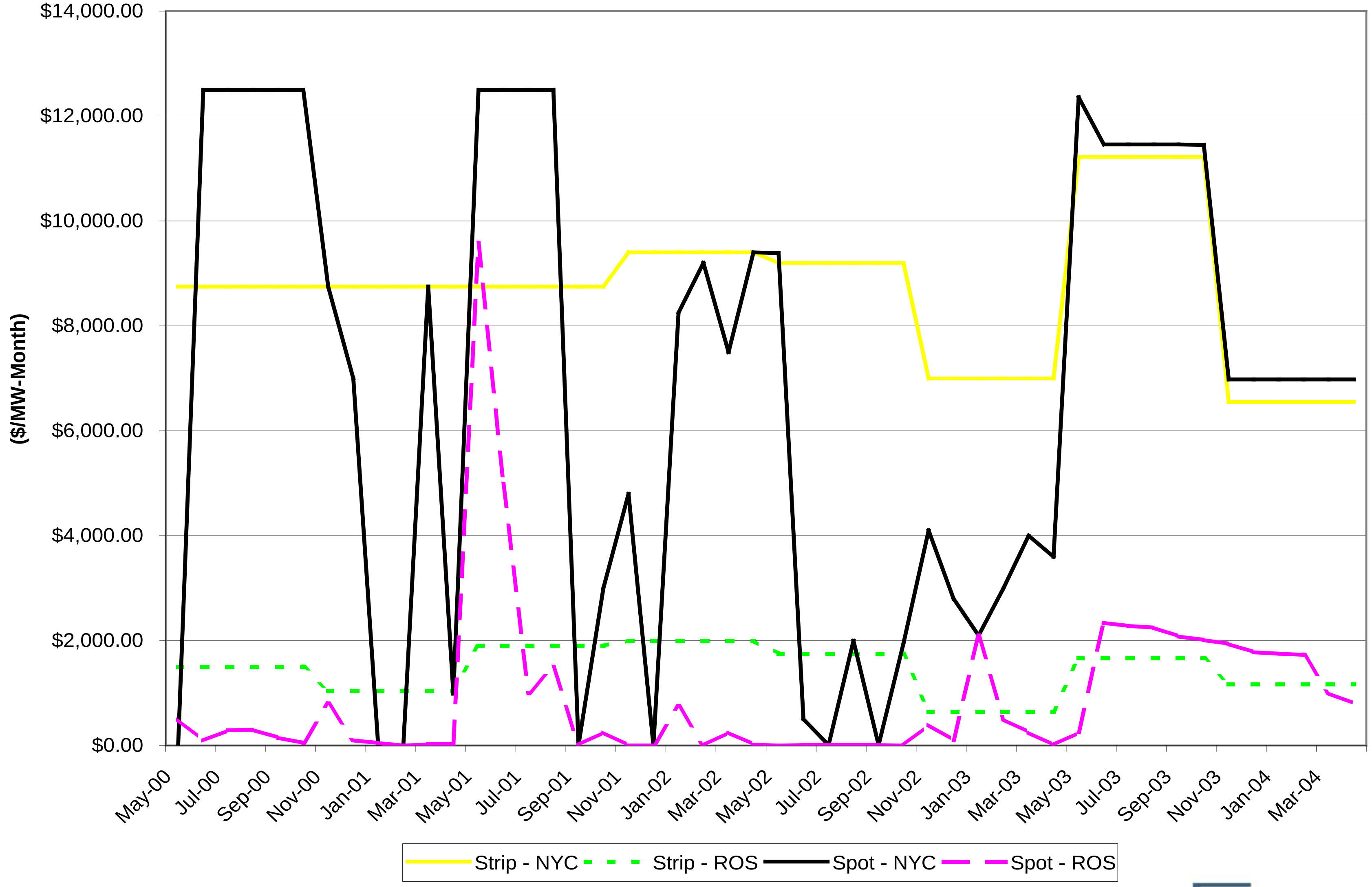
PJM 12-Month Rolling Average UCAP Payment ($/MW Year)



The supply of capacity really does not shift from day to day in response to prices so the PJM daily capacity market resulted in prices that were either zero (in a surplus) or at the price cap (in a shortage).

- Over 1,073 days, January 1, 1999 through March 31, 2004, the UCAP payment averaged less than $1/MWday.
- The UCAP price exceeded $160/MWday for 73 days June through August 2000 and 85 days January through March 2001.

NYISO Strip and Deficiency (Spot) Auction Clearing Prices



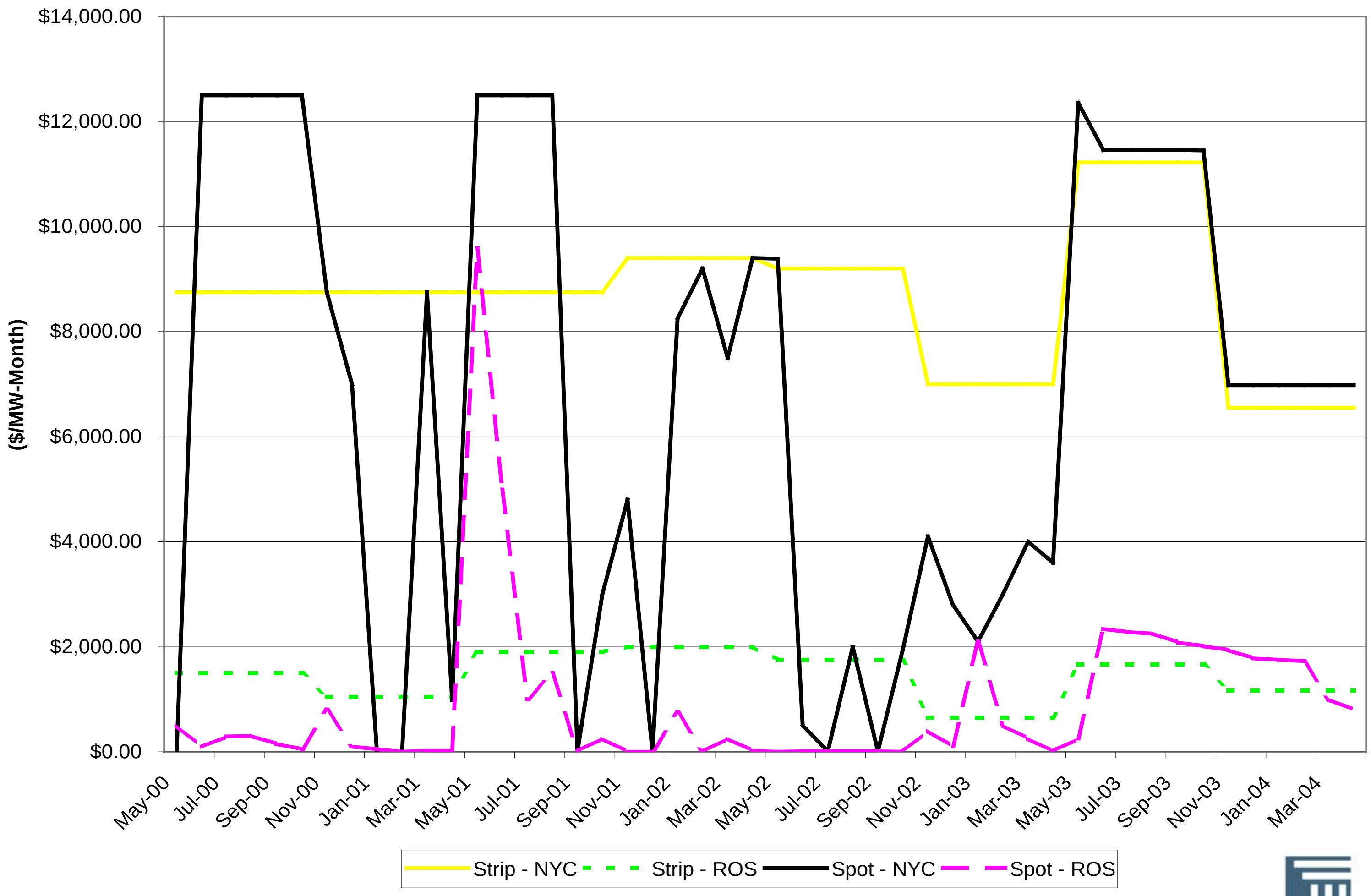
RETAIL ACCESS New York/New England

In New York and New England, prior to implementation of the forward capacity market, each LSE was required to procure capacity in advance of each month, based upon the loads it is expected to serve at the beginning of that month.

- Load serving entities that lose loads during the month were credited for the value of the ICAP acquired to serve the loads they lost based upon the price paid in the ISO's ICAP auction for that month, prorated for the part of the month in which they did not serve that load.
- Load serving entities that gained loads were assessed a charge that is calculated in a similar manner.

New York's capacity market includes a voluntary "strip auction" in which market participants buy capacity covering all six months of the capability periods (May-October, November-April) and monthly auctions.

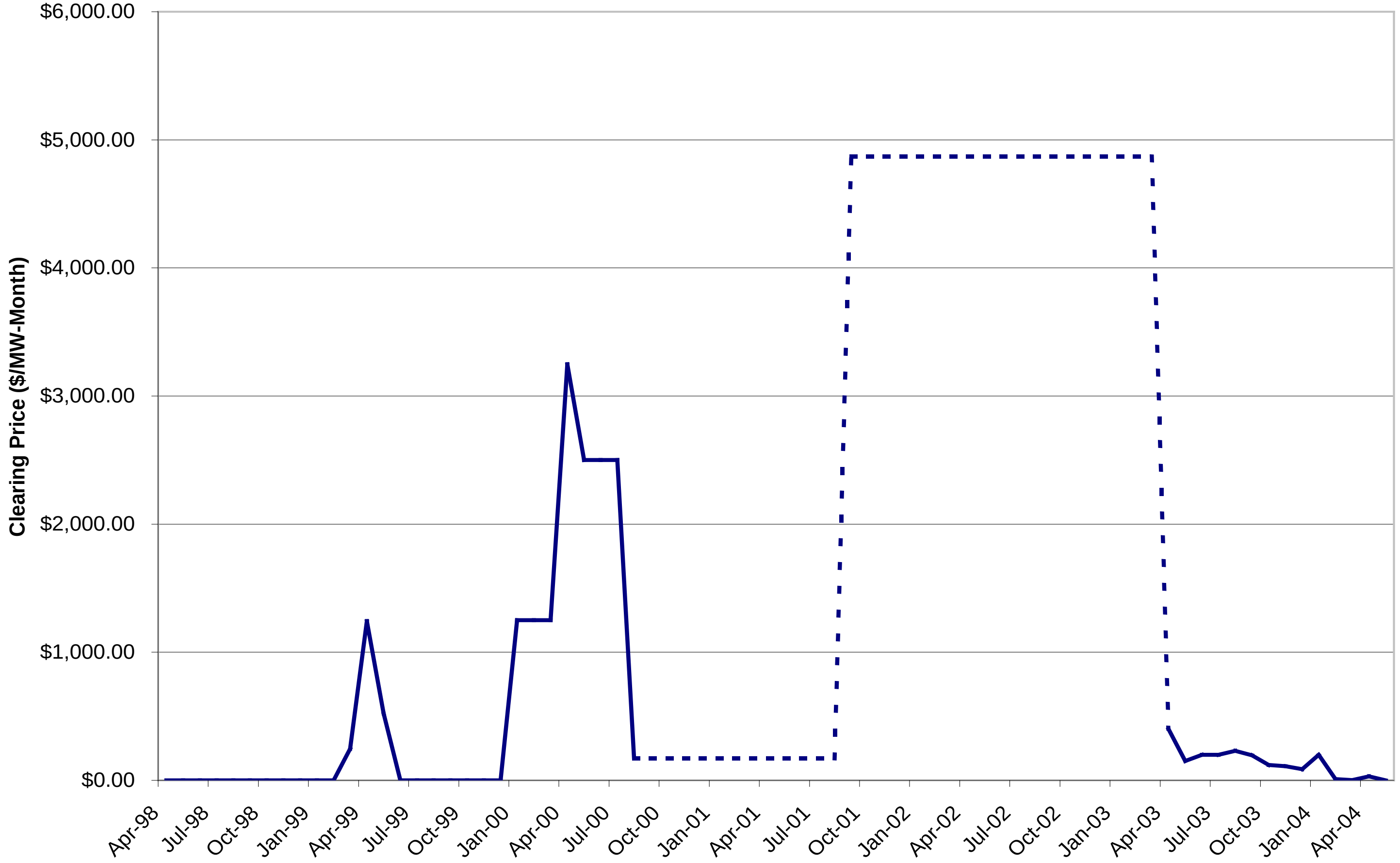
NYISO Strip and Deficiency (Spot) Auction Clearing Prices



New York’s UCAP auction prices were higher and more stable than in PJM or ISO New England in the 2000-2003 period, but the monthly prices were also volatile and low.

- While a monthly auction duration was an improvement over the daily auction in PJM, the reality is that ICAP resources do not exit or enter in response to variations in monthly UCAP prices.
- With both supply and demand fixed, the monthly auction price tends to be either zero or at the price cap (deficiency payment).

NEPOOL Monthly Capacity Market Results



*From August 2000 through March 2003 the graph portrays at the deficiency price.

ISO-NE's capacity markets initially exhibited the same zero or price cap behavior seen in PJM and New York.

- This was followed by a long period with no auction, then prices far too low to sustain any generating capacity.

Deficiency Charges

Capacity markets need to provide incentives for load serving entities to meet their capacity requirements. This incentive was provided in the initial capacity market designs by deficiency charges for load serving entities that failed to acquire capacity.

- The capacity deficiency penalty has generally been based on estimates of the cost of building additional capacity to meet capacity requirements.
- At one time, PJM’s penalty for load serving entities failing to meet their requirements was prorated by the number of days on which the load serving entity was short of capcity.
- Load serving entities that were short on peak load days would pay only a small portion of the cost of developing additional capacity in penalties.

- On high load days in PJM and adjacent regions, however, the ability to export energy and capacity was often worth far more than 1/365 times the annual capacity charge.

- Consequently, PJM began to be capacity short on the hottest days of the year.

RETAIL ACCESS — Deficiency Charges

PJM subsequently modified its rules to provide that load serving entities that were short of capacity at any time during a period (that varied from 3 to 5 months) would be considered deficient for the entire period unless the deficiency arose from a load shift.

- Load serving entities had from 10-40 days to cure a deficiency before PJM deem not to have resulted from a load shift.
- This change reduced the incentive for load serving entities to deliberately run short of UCAP.
- Load serving entities that were gaining load still had an incentive to arbitrage the daily deficiency charge and only cover their new load when the capacity price was low. Whenever there was much load switching between load serving entities, this behavior would cap capacity prices.

New York, by contrast, initially considered a load serving entity to be deficient for a six-month period. This deficiency period was later shortened to a month.

- The New York ISO purchased capacity to cover the obligations of load serving entities that had not nominated sufficient UCAP to cover their obligations for each month, through a centrally conducted auction.
- Load serving entities could continue to nominate resources to meet their share of the requirement.
- But if they did not do so, the ISO would buy UCAP for them for that month in the auction (and send them the bill).

This system has been somewhat altered by the capacity market demand curve implemented by the New York ISO.

The switch to forward capacity markets design in PJM and New England (discussed in Section IIIB) largely eliminated these issues because the RTO, not the load serving entity makes the procurement decision, and capacity costs are simply allocated to the load serving entities.

There is no direct option for a load serving entity to choose not procure capacity and instead pay deficiency charges in these designs.

H. Market Power

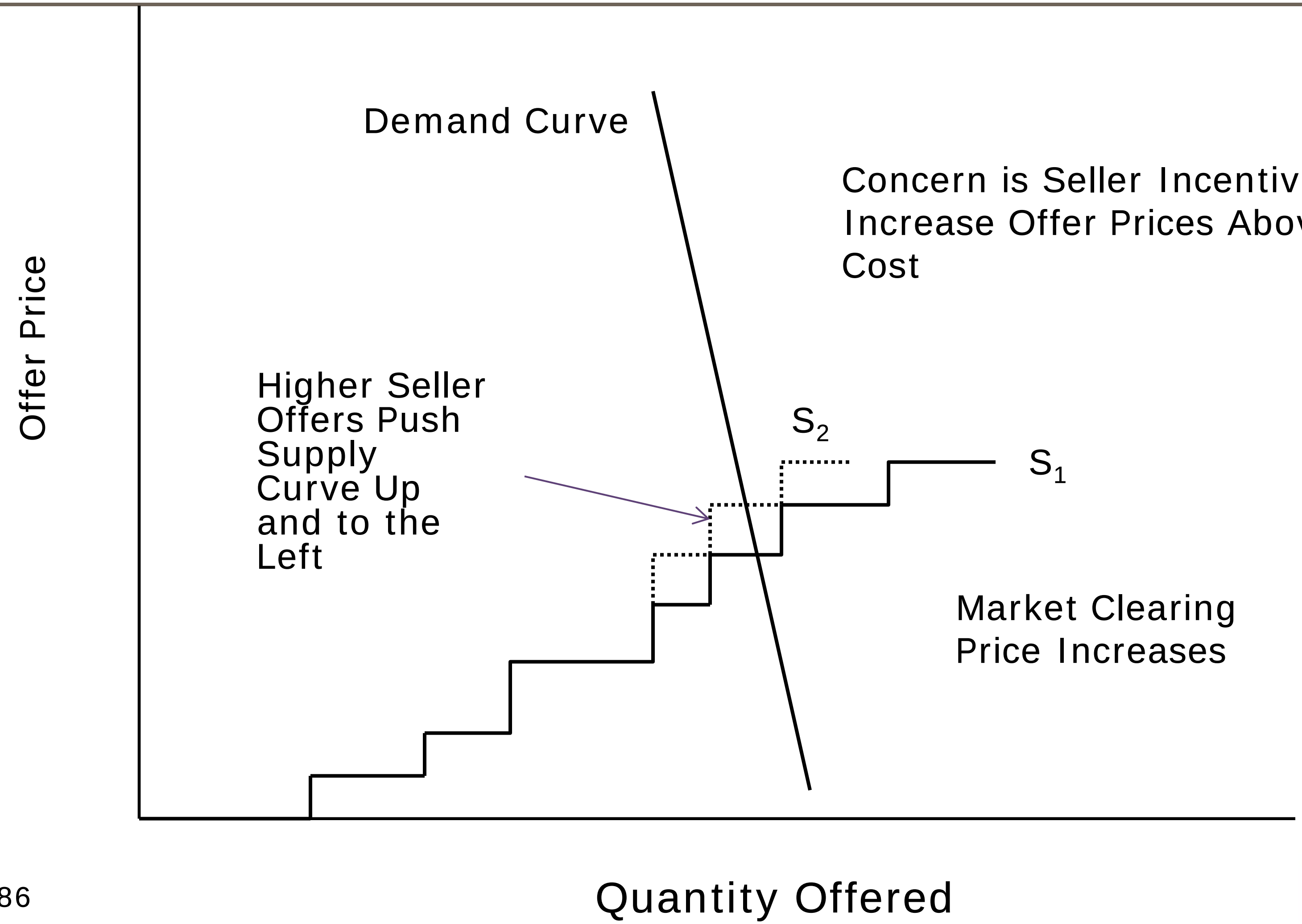
OVERVIEW

- Defining seller and buyer market power in electric capacity markets.

- Testing for potential market power in capacity markets.

- Mitigating market power in capacity markets.

SELLER MARKET POWER

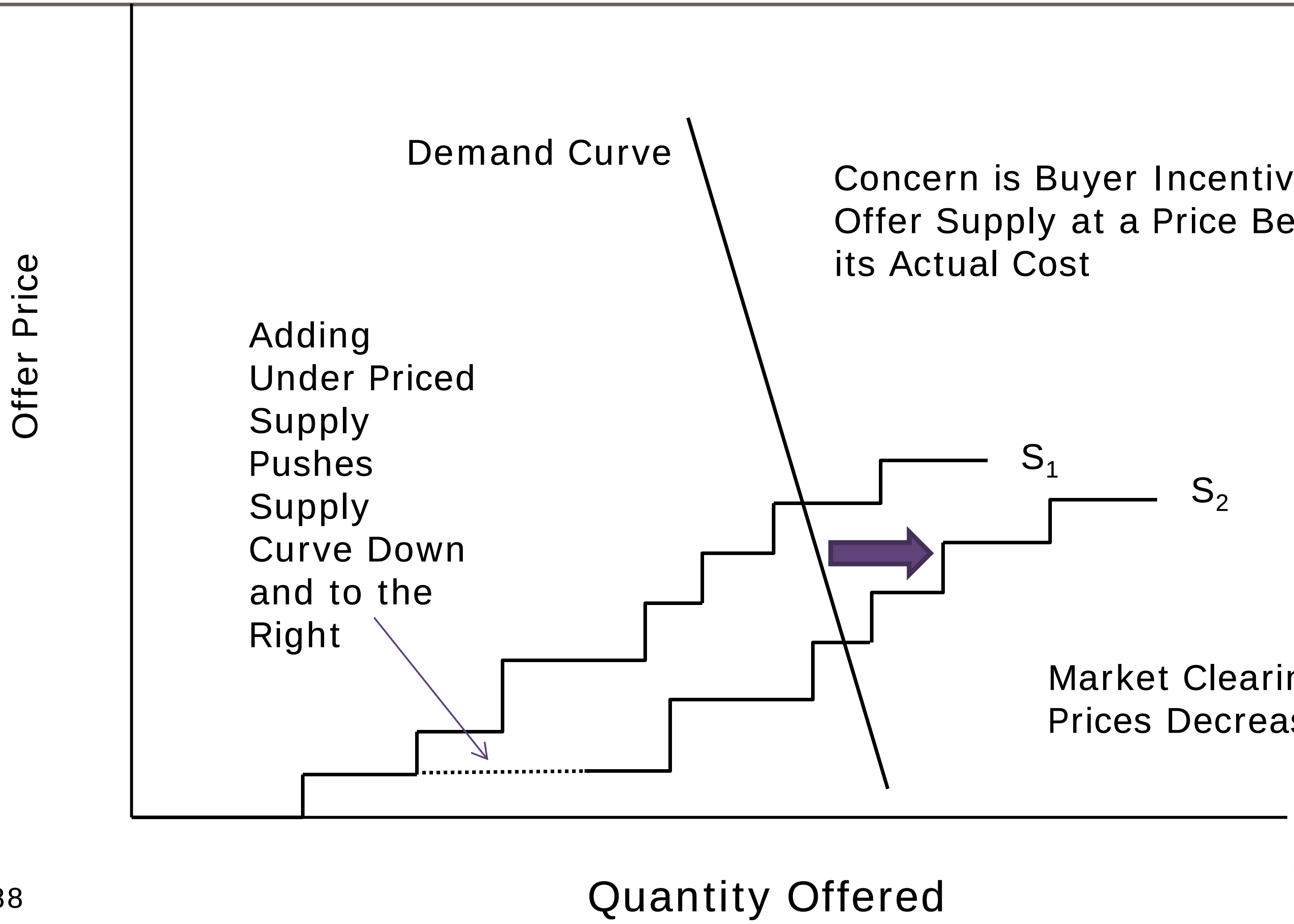


SELLER MARKET POWER

Seller market power is the ability to profitably increase price above competitive levels for a sustained period of time.

- Seller's exercise market power by withholding supply.
- Supply can be withheld either physically or economically. Physically withholding capacity entails shutting capacity down, derating it below its actual capability, or uneconomically exporting the capacity. Economically withholding capacity entails offering the capacity at a high price.
- The exercise of market power entails a seller foregoing revenues on withheld capacity in order to increase the price received for the remaining units of capacity.

BUYER MARKET POWER



BUYER MARKET POWER

Buyer market power is the ability to depress price below the competitive level for a sustained period of time either by uneconomically withholding demand or providing uneconomic supply.

- Withholding of demand is generally not permitted in current electric capacity markets in which the ISO determines the capacity requirement.
- Buyer market power can potentially be exercised by contracting for high cost capacity outside the centralized capacity market and offering this supply at below cost prices in capacity market auctions. This reduces the price paid for capacity purchased at the clearing price in the capacity market auction.

TESTING FOR SELLER MARKET POWER

A variety of approaches are used to test for seller market power in capacity markets.

- Pivotal Supplier test;
- Three-pivotal supplier test;
- Market concentration indices;
- Seller offer analysis.

These approaches are used individually or collectively depending upon the region.

TESTING FOR SELLER MARKET POWER

Pivotal supplier test:

The pivotal supplier test determines whether an Individual seller’s supply is necessary to meet demand.

Total supply minus seller supply > market demand

- If this result is positive, the seller is not pivotal.
- If this result is negative the seller is pivotal.

If a supplier is found to be pivotal, market power tests typically (but not always) assume that the supplier could profitably withhold supply.

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TESTING FOR SELLER MARKET POWER

In New York, a supplier is defined as “pivotal” if it fails the pivotal supplier test and controls a threshold amount of capacity (UCAP) within specified regions:

- 500 megawatts in Zone J
- 650 megawatts in Lower Hudson Valley capacity zone (load zones G, H, I, J)

TESTING FOR SELLER MARKET POWER

Three pivotal supplier test:

The three pivotal supplier test determines whether three individual sellers' supply is necessary to meet demand.

Total Effective Supply - Supply of Two largest owners - Supply of Owner Being Tested < Relief Demand

The two largest owners will fail if any other owner fails.

If the two largest suppliers fail, all suppliers will fail.

TESTING FOR SELLER MARKET POWER

Market Concentration:

Market concentration is often measured using the Herfindahl-Hirschman Index (HHI).

- The HHI is a function of the number of firms in the market and their respective market shares;
- It is calculated by summing the squares of individual market shares, expressed as percentages, of all suppliers in the market;

HHIs are imperfect measures of whether markets are competitive, but are widely used by regulatory agencies worldwide as one measure of market structure.

TESTING FOR SELLER MARKET POWER

- Market Concentration Measures—Typical Standards:

UNCONCENTRATED MARKET (HHI less than 1000)			**MODERATELY CONCENTRATED MARKET (HHI between 1000 and 1800)**			**HIGHLY CONCENTRATED MARKET (HHI greater than 1800)**		
Company	**Market Share (%)**	**Market Share Square**	**Company**	**Market Share (%)**	**Market Share Square**	**Company**	**Market Share (%)**	**Market Share Square**
Company A	10	100	Company A	24	576	Company A	36	1,296
Company B	8	64	Company B	8	64	Company B	4	16
Company C	7	49	Company C	7	49	Company C	7	49
Company D	13	169	Company D	13	169	Company D	15	225
Company E	5	25	Company E	5	25	Company E	5	25
Company F	8	64	Company F	8	64	Company F	3	9
Company G	6	36	Company G	6	36	Company G	6	36
Company H	8	64	Company H	8	64	Company H	2	4
Company I	15	225	Company I	7	49	Company I	7	49
Company J	9	81	Company J	9	81	Company J	9	81
Company K	11	121	Company K	5	25	Company K	5	25
HHI		**998**	**HHI**		**1,202**	**HHI**		**1,815**

TESTING FOR SELLER MARKET POWER

Seller Offer Price Analysis:

- Some regions may apply mitigation without applying any structural test for market competitiveness.
- Mitigation with price ceilings where offers above ceiling are reviewed.
- Offer prices are scrutinized in detail. Seller must produce various data on costs which are then examined by a market monitor.
- Has been used in New England in association with forward capacity market.

MITIGATING SELLER MARKET POWER

Suppliers failing a market power test must submit offers that are capped at some measure of their going forward or opportunity costs.

- Accurately measuring going forward costs in capacity markets is very complex.
    - It must take account of normal going forward costs, allow recovery of extraordinary going forwards costs (investments needed for environmental compliance) over an uncertain number of future operating years, and account for expected energy and ancillary service revenues.
    - In forward capacity markets, it needs to project what environmental costs may arise between the date of the auction and the delivery year.
- Calculating opportunity costs in adjacent capacity markets can also be difficult, particularly if they operate in different time frames.

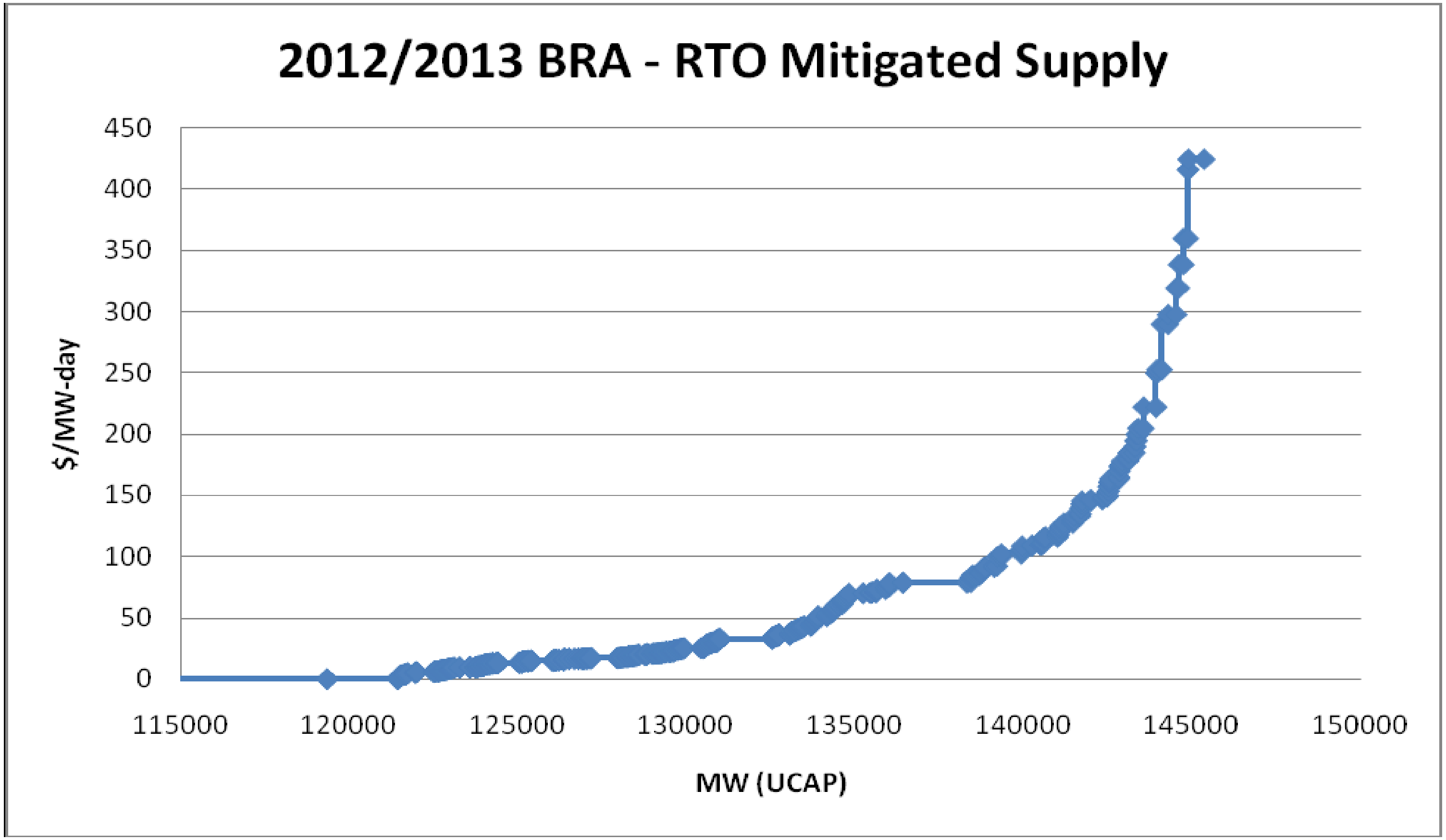
MITIGATING SELLER MARKET POWER

PJM bases its seller market power mitigation on the three pivotal supplier test.

- If the top two suppliers have a material amount of capacity, this test requires a lot of excess capacity for any supplier to pass the test.
- The typical outcome in PJM is that every capacity supplier in almost every region is subjected to mitigation in every auction.

MITIGATING SELLER MARKET POWER

- PJM--Example of mitigated supply curve:



TESTING FOR SELLER MARKET POWER

In New York, mitigation is only applied in the spot auction. This is the only mandatory auction.

- Capacity buyers and sellers submit voluntary offers in the strip and monthly auctions and these offers are not subject to mitigation.
- Only suppliers that fail the pivotal supplier test are subject to mitigation, so many suppliers are not subject to mitigation in the spot auction.
- Because the spot auction occurs shortly before the delivery month, most costs are sunk by that time and if capacity is offered. In addition, much capacity is sold in the strip or monthly auctions, so most capacity is offered at zero with the auction price set by the demand curve.

MITIGATING SELLER MARKET POWER

Offer prices of “new supply” are typically presumed to be competitive and not subject to offer capping, but:

- Defining “new supply” provided by imports and demand response can be difficult.
    - Does it make sense to apply seller side mitigation to demand response and capacity imports?

- Defining when supply offered by repowered units should be treated as “new supply” can also be complex.
- New supply may also be subject to offer floors to limit the exercise of buyer side market power.

TESTING FOR BUYER MARKET POWER

Buyer side offer price mitigation for new capacity is equally complex and hard to evaluate, requiring assessment of:

- Expected investment costs;
- Discount rates
- Future going forward costs;
- Future energy and ancillary service revenues – relying on historical data is workable and objective but can also be wildly inaccurate.
- Future capacity market prices.

TESTING FOR BUYER MARKET POWER

Buyer side offer price mitigation may a number of exemptions, depending on the ISO:

- Self-Supply -- procurement by load serving entities that fall within thresholds for the level of their spot market capacity purchases (net short thresholds);
- Competitive entry – capacity procurement by load serving entities that will not recover their costs in regulated utility rates or state payments;
- Intermittent resources;
- Nuclear plants;
- Exemptions for capacity located outside specified regions;
- Exemption/allowance for capacity temporarily depressing capacity market prices in small zones.

MITIGATING BUYER MARKET POWER

MOPR Screen Price for 2016/2017 RPM Base Residual Auction

Combustion Turbine	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
Benchmark CONE (2015/2016 BRA Value): Levelized Revenue Requirement, $/MW-Year	$140,000	$130,600	$127,500	$134,500	$114,500
12 Months Handy Whitman Index (July 1, 2012)	8.9%	8.9%	9.4%	8.9%	9.1%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic
2016/2017 BRA CONE, escalated by Handy Whitman Index, $/MW-Year	$152,460	$142,223	$139,485	$146,471	$124,920
Zone in the CONE Area with highest energy revenue	DPL	BGE	APS	MetEd	Dominion
Historic (2010-2012) Net Energy Revenue Offset for the Zone with highest energy revenues in the CONE Area, $/MW-Year	$37,852	$44,707	$28,489	$32,929	$34,129
Ancillary Services Offset, $/MW-Year per Tariff	$2,199	$2,199	$2,199	$2,199	$2,199
Net CONE, $/MW-Day, ICAP Price	$307.97	$261.14	$298.08	$305.05	$242.72
Net CONE, $/MW-Day, UCAP Price	$326.55	$276.90	$316.06	$323.45	$257.36
MOPR Floor Offer Price for Combustion Turbine: 100% Net CONE, $/MW-Day, UCAP Price	**$326.55**	**$276.90**	**$316.06**	**$323.45**	**$257.36**

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2016/2017 =	5.69%

MITIGATING BUYER MARKET POWER

MOPR Screen Price for 2016/2017 RPM Base Residual Auction

Combined Cycle	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
Benchmark CONE (2015/2016 BRA Value): Levelized Revenue Requirement, $/MW-Year	$173,000	$152,600	$166,000	$166,000	$147,000
12 Months Handy Whitman Index (July 1, 2012)	8.9%	8.9%	9.4%	8.9%	9.1%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic
2016/2017 BRA CONE, escalated by Handy Whitman Index, $/MW-Year	$188,397	$166,181	$181,604	$180,774	$160,377
Zone in the CONE Area with highest energy revenue	DPL	BGE	APS	MetEd	Dominion
Historic (2010-2012) Net Energy Revenue Offset for the Zone with highest energy revenues in the CONE Area, $/MW-Year	$92,898	$102,130	$80,391	$82,382	$89,000
Ancillary Services Offset, $/MW-Year per Tariff	$3,198	$3,198	$3,198	$3,198	$3,198
Net CONE, $/MW-Day, ICAP Price	$252.88	$166.72	$268.53	$260.80	$186.79
Net CONE, $/MW-Day, UCAP Price	$268.14	$176.78	$284.74	$276.54	$198.06
MOPR Floor Offer Prices for Combined Cycle: 100% Net CONE, $/MW-Day, UCAP Price	**$268.14**	**$176.78**	**$284.74**	**$276.54**	**$198.06**

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2016/2017 =	5.69%

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MITIGATING BUYER MARKET POWER

MOPR Screen Price for 2016/2017 RPM Base Residual Auction

Integrated Gasification Combined Cycle (IGCC)					
	CONE Area 1	**CONE Area 2**	**CONE Area 3**	**CONE Area 4**	**CONE Area 5**
Benchmark CONE (2015/2016 BRA Value): Levelized Revenue Requirement, $/MW-Year	$582,042	$558,486	$547,240	$537,306	$541,809
12 Months Handy Whitman Index (July 1, 2012)	8.9%	8.9%	9.4%	8.9%	9.1%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic
2016/2017 BRA CONE, escalated by Handy Whitman Index, $/MW-Year	$633,844	$608,191	$598,681	$585,126	$591,114
Zone in the CONE Area with highest energy revenue	DPL	BGE	APS	MetEd	Dominion
Historic (2010-2012) Net Energy Revenue Offset for the Zone with highest energy revenues in the CONE Area, $/MW-Year	$129,872	$138,839	$96,392	$116,461	$107,397
Ancillary Services Offset, $/MW-Year per Tariff	$3,198	$3,198	$3,198	$3,198	$3,198
Net CONE, $/MW-Day, ICAP Price	$1,371.98	$1,277.14	$1,367.37	$1,275.25	$1,316.49
Net CONE, $/MW-Day, UCAP Price	$1,454.76	$1,354.19	$1,449.87	$1,352.19	$1,395.92
MOPR Floor Offer Prices for IGCC: 100% Net CONE, $/MW-Day, UCAP Price	**$1,454.76**	**$1,354.19**	**$1,449.87**	**$1,352.19**	**$1,395.92**

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2016/2017 =	5.69%

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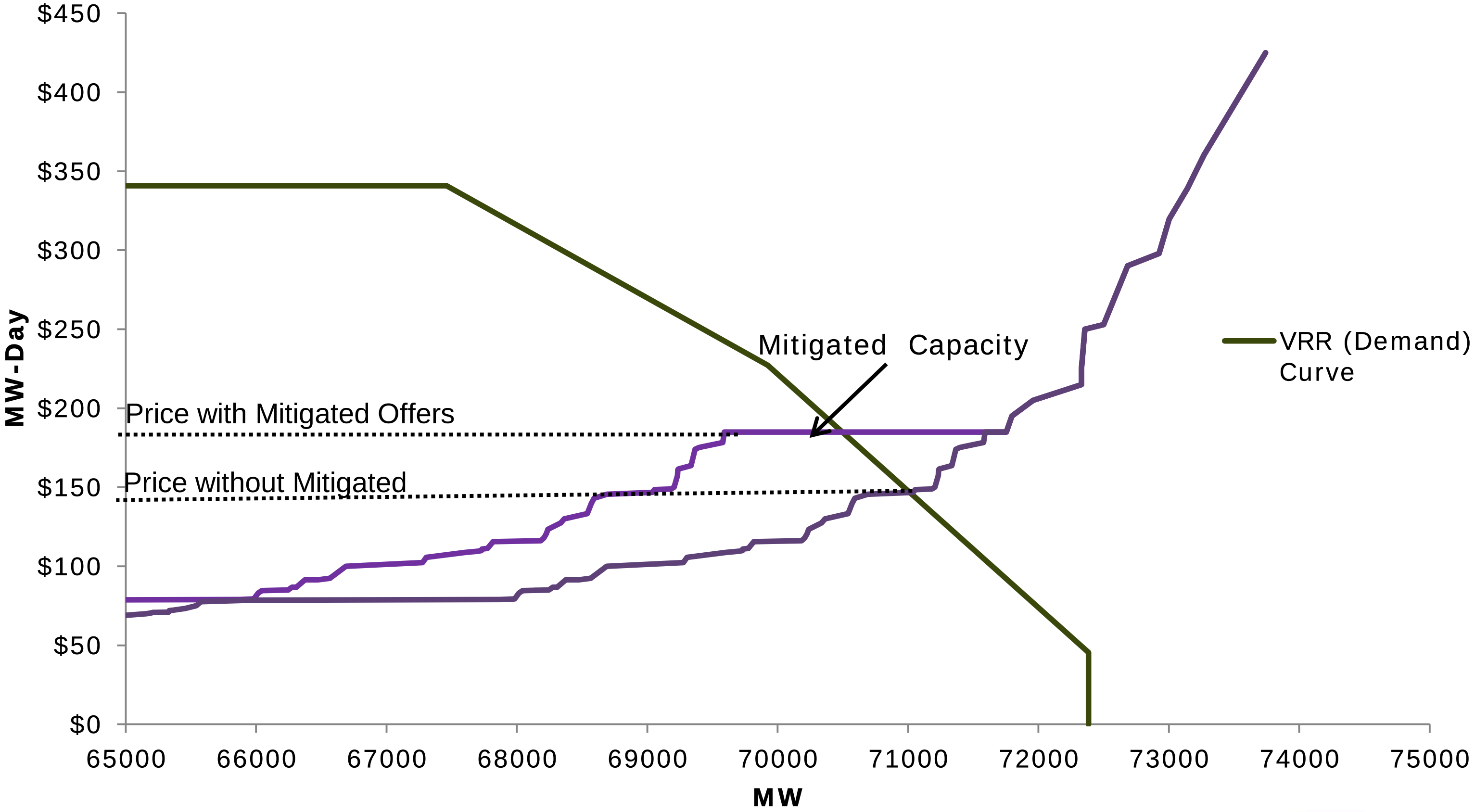
MITIGATING BUYER MARKET POWER

- Example of intended impact of MOPR on PJM’s RPM.



MITIGATING BUYER MARKET POWER

Buyer side mitigation was originally focused on new capacity but is now being extended to the going forward costs of existing capacity or repowered capacity.

- Uneconomic capacity retention can be used to slow a rise in capacity market prices as the cost of compliance with environmental regulations eliminates a pre-existing supply surplus;
- However, utilities with POLR obligations have a need to enter into short duration forward contracts to hedge their POLR obligations. The ISO should not get involved in regulating the prices of these contracts, which can be very difficult if the contracts cover capacity and energy.

STATE PROGRAMS

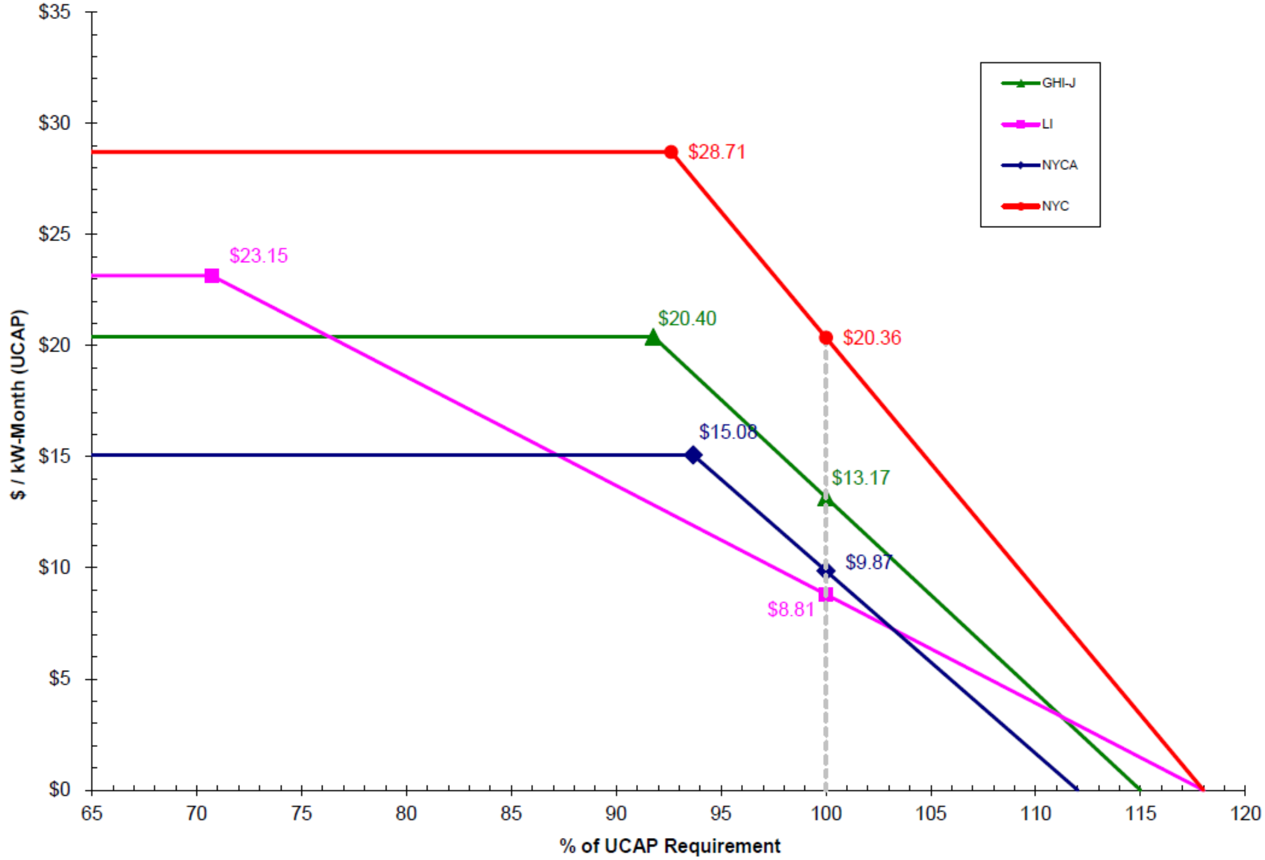
Several states, Connecticut, New Jersey and Maryland have had legislative actions focused on development of new gas fired electric generation stations.

- These legislative actions have resulted in new supply being solicited in order to resolve a perceived problem (e.g., in CT—high congestion costs, in NJ reliability, and in MD reliability).
- Power sale contracts emerging from these legislative actions have been financial contracts for differences which required the sellers to offer capacity into capacity markets at low prices. These contracts have been a major focus of buyer side mitigation.
- Buyer side market power mitigation has not prevented large additions of new capacity in PJM and NYISO capacity auctions.

III. Design Evolution in Capacity Markets

A. Capacity Market Demand Curves

Summer 2015 Demand Curves



DEMAND CURVE

New York, then PJM, and most recently ISO New England have attempted to address the problem of fixed supply and demand in capacity market auctions by introducing a demand curve into their capacity market auctions. New York bases its monthly spot market auction on a demand curve so that:

- The amount of UCAP purchased depends on the price of UCAP.
- A small excess supply causes the price to fall, but not to zero.
- A small supply shortage causes the price to rise, but not without bounds.

NYISO NYC Capacity Spot Auction Prices

Simulated Loss-of Load Probabilities for New York Control Area

Capacity	Percent of Target	Loss of Load Probability
34,761	90%	0.583
35,920	93%	0.324
36,692	95%	0.226
37,851	98%	0.133
38,623	100%	0.1
39,782	103%	0.074
40,455	105%	0.068
41,713	108%	0.055
42,486	110%	0.046
43,644	113%	0.044
44,417	115%	0.044
45,576	118%	0.044

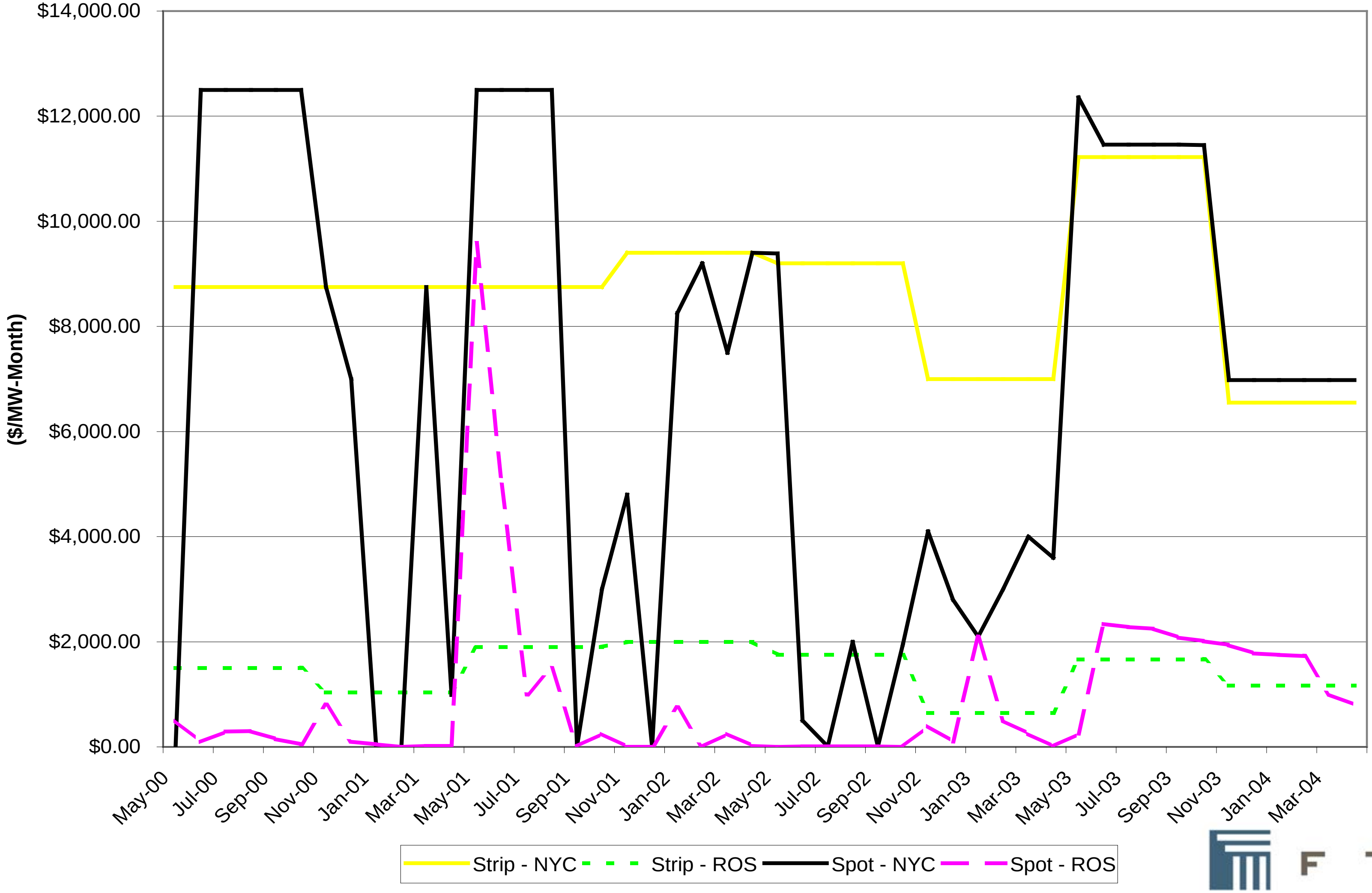
Source: Scott Harvey, William Hogan, Susan Pope, "Evaluation of the New York Capacity Market," March 5, 2013. Tables 17 and 18.
Incremental Capacity is added to zones A, C, and D.

DEMAND CURVE

Implementing a demand curve for capacity recognizes that because the capacity requirement is based on a probabilistic evaluation:

- The value of a few additional megawatts of capacity is not zero, nor does a shortage of a few megawatts have dire consequences.
- In the GE MARS simulations that the New York ISO uses to set its capacity market requirements, the loss of load expectation declines as capacity rises above the target level. It does not fall to zero for a small capacity surplus.

NYISO Strip and Deficiency (Spot) Auction Clearing Prices



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DEMAND CURVES

The capacity market demand curve appears to have reduced the volatility of capacity prices in New York and PJM. Nevertheless, it has some limitations.

- The demand curve in effect sets an administrative price for the target level of capacity and allows variations in the amount offered at this price to raise or lower the price. Errors in setting the administrative price will result in capacity shortfalls or surpluses relative to the target.
- The NYISO implementation of the demand curve may somewhat undermine forward contracting because the UCAP requirement of all load serving entities is determined in the spot market auction. Load serving entities do not know exactly how much capacity they need to contract for until after the auction.

DEMAND CURVES

The New York demand curve is implemented only in the “spot market auction.” The current New York design provides for up to 3 auctions covering each period.

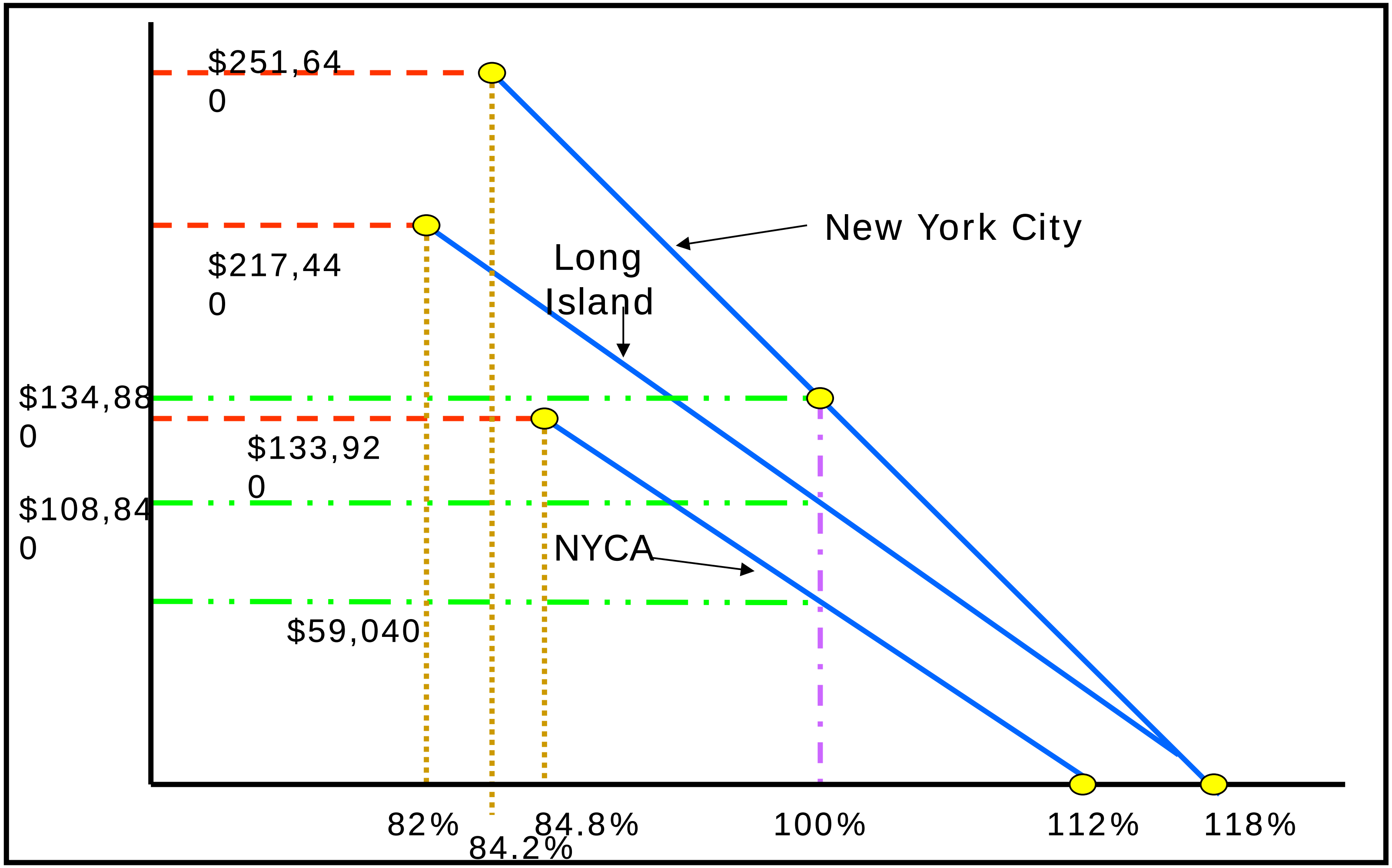
- Voluntary Capability Period (Strip Auction)
- Voluntary Monthly Auction
- NYISO run spot market auction with demand curve

DEMAND CURVES

The demand curve creates some cost volatility for entities entering into long-term contracts.

- When the price of capacity is low in the auction, the demand curve increases their capacity market obligation, requiring incremental capacity purchases, albeit at the low spot prices.
- When the price of capacity is high in the auction, the demand curve reduces their capacity market obligation, making them capacity sellers at the high spot price.

NYISO Summer 2003 UCAP Demand Curve



DEMAND CURVES

The New York ISO demand curve system provides improved resource adequacy incentives as long as:

- The New York ISO target capacity price is reasonably close to the long-run equilibrium price/cost of capacity.
- Locational market shares and demand curve elasticity's are low enough to render withholding by suppliers and uneconomic investment by buyers unprofitable.
- Resource suppliers are willing to make capacity commitments based on short-term contracts and stable spot market capacity market prices.

DEMAND CURVES

PJM introduced a demand curve for capacity as part of its RPM design (first forward auction in April 2007).

ISO New England introduced a demand curve for capacity in FCA 9 (2015 auction year) Docket ER14-1634.

B. Long-Term Price Signals and Forward Capacity Markets

FORWARD PRICE SIGNALS

PJM and ISO- New England have attempted to improve the forward price signal provided by their capacity market by conducting forward auctions in a time frame that allows some types of new generation resources (combustion turbines and combined cycles) to begin the construction process after the resource has cleared in the forward capacity auction.

- This forward auction design allows a resource to lock in one year of capacity market revenues at the auction price before committing to construction.
- Locking in the capacity price one year at a time does not provide much more long-term price assurance to support entry than does the New York ISO spot and strip capacity market auctions.

FORWARD PRICE SIGNALS

- ISO- NE has rules allowing new resources to opt to sell their capacity for up to five years (recently increased to seven years in FCA 9, docket ER14-1639) at the price at which the capacity initially clears in the forward auction, indexed for inflation. These rules were triggered in FCA 7 for a new resource in the Northeast Massachusetts/Boston region.
- PJM has similar rules with a five year time frame but they have not yet been triggered.

These rules would not be needed if the auction price provided an efficient signal for investment in new capacity and was paid to both new and existing capacity.

FORWARD PRICE SIGNALS

In forward capacity market designs, capacity requirements tend to be determined by planners, then contracted for by the ISO.

Excludes ATSI, Duke Ohio, and Eastern Kentucky in all years

	PJM Projected Peak Load	Weather Adjusted Peak Load
2010-2011	144592	135080
2011-2012	142390	134125
2012-2013	144857	136595
2013-2014	147270	137507
2014-2015	145404	138345

Source: PJM Base Residual Auction Planning Parameters:
http://www.pjm.com/markets-and-operations/rpm.aspx

FORWARD PRICE SIGNALS

Projections of weather adjusted capacity needs generally become more accurate as the operating year approaches.

- The level of economic activity can be projected more accurately.
- The level of fuel prices and power prices can be estimated more accurately.
- Hence, as the operating year approaches, it may become apparent that not all of the capacity contracted for in forward auctions will be needed to maintain reliability, or perhaps, that having additional capacity would be valuable.

FORWARD PRICE SIGNALS

PJM has a quasi financial forward auction design that has allowed capacity suppliers to buy out of their forward supply obligation when PJM scales back its load forecast.

Auction	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
1st Incremental	-60.3	-2494.4	-2610	-1815.9	-1419
2nd Incremental	-2376.8	-3602.1	-1566.9	-913.2	-4293.7
3rd Incremental	-1979.3	-465	1295.5	2	NA
Total	-4416.4	-6561.5	-2881.4	-2727.1	-5712.7

This is an efficient design but the ISO has to take steps to ensure that forward capacity market sales are supported by real-resources that could be available.

Source: PJM Incremental Auction Results: http://www.pjm.com/markets-and-operations/rpm.aspx

FORWARD PRICE SIGNALS

There has been a tendency for capacity prices in the PJM incremental auctions to fall well below prices in the base auction, particularly for the broader regions such as RTO and Eastern MAAC.

2012-2013							
	$ per Day				MW Change		
	RTO	EMAAC	PSE&G		RTO	EMAAC	PSE&G
Base	16.46	139.73	139.73	**Base**			
1st Incremental	16.46	153.67	153.67	**1st Incremental**	-60.3	1172.4	453.5
2nd Incremental	13.01	48.91	48.91	**2nd Incremental**	-2376.8	-303.5	10.2
3rd Incremental	2.51	2.51	2.51	**3rd Incremental**	-1979.3	-542.5	-39.3

FORWARD PRICE SIGNALS

2013-2014							
	$ per Day				MW Change		
	RTO	EMAAC	PSE&G		RTO	EMAAC	PSE&G
Base	27.73	245	245	**Base**			
1st Incremental	20	178.85	178.85	**1st Incremental**	-2494.9	316.6	170.1
2nd Incremental	7.01	40	40	**2nd Incremental**	-3602.1	-770.5	-359.5
3rd Incremental	4.05	188.44	188.44	**3rd Incremental**	-465	-514	-253.9

2014-2015							
	$ per Day				MW Change		
	RTO	EMAAC	PSE&G		RTO	EMAAC	PSE&G
Base	125.99	136.5	136.5	**Base**			
1st Incremental	5.54	16.56	16.56	**1st Incremental**	-2610	-807.9	-67.8
2nd Incremental	25	56.94	56.94	**2nd Incremental**	-1566.9	-654.9	-132.5
3rd Incremental	25.51	132.2	132.2	**3rd Incremental**	1295.5	614.2	145

2015-2016							
	$ per Day				MW Change		
	RTO	EMAAC	PSE&G		RTO	EMAAC	PSE&G
Base	136	167.46	167.46	**Base**			
1st Incremental	43	111	122.94	**1st Incremental**	-1815.9	-1045.5	-210.7
2nd Incremental	136	153.56	167.46	**2nd Incremental**	-913.2	-641.3	-19.3
3rd Incremental	163.2	184.77	185	**3rd Incremental**	2	-435.1	2

FORWARD PRICE SIGNALS

It has been observed that much of the capacity that is bought back in the incremental auctions has been demand response and suggested that this pattern suggests a design problem.

- It is important that capacity resources clearing in the base auction be able to perform if needed.
- However, what is surprising about the outcomes in the incremental auctions is not that so much demand response was bought back, but that more was not bought back.

FORWARD PRICE SIGNALS

Since the cost of providing demand response should be mostly the cost of interrupting power consumption on a high load day, most of the cost of providing it should not be sunk prior to the operating year, i.e. most of the cost should be avoidable if the demand response is not needed.

- Why does any demand response stay in the capacity market when capacity prices fall to extremely low levels in incremental auctions? The failure of more demand response to buy back its obligation implies that most of the costs of providing demand response are sunk prior to the operating year, this makes no sense!
- Is the answer state programs that procure demand response and require that it be provided in the operating year regardless of incremental capacity prices?

FORWARD PRICE SIGNALS

Artificially low capacity prices in incremental auctions do not benefit consumers, low prices victimize consumers.

- When PJM buys capacity at a high price in the base auction and the capacity is later sold back at a low price in an incremental auction, the low price raises consumer costs. PJM recovers only a small portion of the money spent to procure the capacity in the base auction and this loss is borne by power consumers.
- RTO's should analyze whether requirements on demand response procured by state programs are artificially depressing incremental auction prices, inflating capacity supplier profits, and raising costs for power consumers.

FORWARD PRICE SIGNALS

Regardless of whether auctions are cleared for one year at a time of two or three years in advance, there is nothing to prevent load serving entities from entering into 5, 10, or 20 year capacity contracts with new or existing generation resources.

- One market problem that tends to deter such long-term contracting in most (but not all) parts of PJM, New York, and ISO- New England is that many load serving entities do not have long-term load serving obligations.
- Entities having such long term load serving obligations (Such as Long Island Power Authority in New York) and various municipals and cooperatives in PJM, and investor owned utilities in Virginia and West Virginia have been able to contract long-term for capacity, despite short-term auctions.

FORWARD PRICE SIGNALS New England

The New England forward capacity auction cleared at the floor price in the rest of pool region over the first seven auctions.

- This outcome initially sent the appropriate price signal because there was substantial excess supply in the early auctions.
- This surplus has been a result in part of the down turn in the New England economy, reducing the increase in forecasted capacity requirements, increased supply of demand response, and increased supply of capacity imports.
- Because the New England FCM design did not include a demand curve, small excesses of supply could unduly depress the clearing price, which did not send the appropriate price signal.

FORWARD PRICE SIGNALS New England

The surplus in the New England capacity markets was in part a result of increased generation supply, some from likely low cost increases associated with repowerings and upgrades of existing units, some from renewables receiving additional revenues due to Renewal Portfolio Standard incentives, and a chunk from uneconomic contracts entered into on behalf of Connecticut consumers.

- An interesting market outcome is that most generating resources in New England remained in the capacity market through FCA 7, even though they received less than the floor price and could have exited when the capacity price fell below .8 of the cost of new entry as estimated by the New England ISO.

CONE

An ubiquitous term in the New England FCM Market, the PJM RPM market and the New York ISO demand curve is the cost of new entry or CONE.

- The most important thing to understand about CONE in these markets is that it is not actually the cost of new entry.
- CONE as calculated in these markets is not based on the same projection of energy and ancillary service revenues, cost of capital, expectations of future capacity prices, construction costs or equipment purchase costs used by potential entrants.
- CONE is at best a rough approximation of the cost of new entry and it may be significantly different at times.

C. Pay for Performance

Pay for Performance — New England

In response to its perception of problems with the availability and performance of dispatchable generation, ISO New England prospectively implemented a major design change in its capacity market design in the 2015 auction, FCA 9, covering the 2018-2019 delivery year.

- Under the new design, capacity market suppliers that provide less than their capacity market share of the generation providing energy or reserves during a reserve shortage event will incur a large per megawatt penalty for the deficiency.
- Conversely, suppliers that provide more than their capacity market share of the generation providing energy or reserves during a reserve shortage event (including supply provided by resources with no capacity market obligation) would earn a large per megawatt payment for the additional output.

Pay for Performance New England

ISO New England describes the pay for performance design as a two settlement system between the forward auction and the real-time market.

- It is not a two settlements system between the day-ahead market and real-time, it treats all capacity the same, whether or not the capacity had a day-ahead market schedule.
- The pay for performance design as filed by ISO New England imposed no consequences on load serving entities whose underbidding in the day-ahead market caused a reserve shortage, yet underbidding by load serving entities in the day-ahead market has been a signature feature of ISO New England’s winter reliability problems that motivated the pay for performance design.

Pay for Performance — New England

Although ISO New England's original pay for performance design did not address the adverse reliability impact of underbidding by load serving entities, other than by trying to shift the responsibility for managing the impact of this underbidding onto capacity market suppliers, NEPOOL filed its own version of the pay for performance design which included substantial increases in shortage prices.

- When FERC approved the pay for performance design, it also required that ISO New England implement the increases in reserve shortage prices proposed by NEPOOL. These increases went into effect on December 3, 2014.
- The higher shortage prices may have corrected the past problems with underbidding by load serving entities, although we will need to watch how a few more winter cold spells work out.

Capacity Performance Product PJM

PJM also implemented a new capacity market design in its just completed 2015 capacity market auction. This is the capacity performance product which established a higher performance requirement, and potentially higher payment, for initially a portion of PJM’s overall capacity requirement, and eventually all PJM capacity.

- The capacity performance product provides performance incentives similar to those of ISO New England’s pay for performance design.
- Capacity market suppliers are obligated to provide energy and capacity equal to their share of capacity during reliability events.

Capacity Performance Product PJM

The capacity performance product design differs from the ISO New England design in a variety of details:

- The penalty price is initially based on net cone divided by 30 hours a year;
- The penalty will not apply to generation that is not available due to an approved planned or maintenance outage, with a 72 hour recall for generation on maintenance outages;
- The penalty will not apply to capacity that does not provide energy or reserves because PJM did not commit or dispatch it, as long as it was not economic based on its cost based offer prices.
- The penalties will apply to all capacity in the summer months but only to capacity performance product capacity during the winter and shoulder months.

Capacity Performance Product PJM

Other notable design elements:

- PJM is completing auctions to buy capacity performance product capacity covering the future years for which a base auction has already been held. The design of these auctions was not well thought out and has the potential to lead to unintended outcomes.
- The capacity performance requirement is annual, but aggregated offers can be used to allow demand response, energy limited units and intermittent resources to participate in the capacity market.

D. Peak Energy Rent Deductions

PEAK ENERGY RENTS

Another capacity market design ”innovation” that is currently applied only in ISO-New England, is to adjust the capacity payment for calculated peak energy rents.

- The stated rationale for this design feature was to eliminate any potential incentive for suppliers to exercise market power by effectively taxing away any revenues that generators receive in excess of the calculated incremental costs of a hypothetical generator.
- The peak energy rent adjustment is not contemporaneous but calculated on a rolling 12 month average basis so it eventually taxes away any excess revenues relative to the costs of the hypothetical bench mark generator.[1]

1. Section III. 13.7.2.7.1.1.2

PEAK ENERGY RENTS

The original formulas for calculating peak energy rents assumed that the hypothetical generator was gas fired.

- When gas prices fell far below oil prices with the increase in shale gas production, this formula imposed large losses on oil fired generators in New England whose variable cost exceeded the strike price.
- The formula was changed to calculate peak energy rents based on the higher of gas or oil prices beginning in December 2010.

PEAK ENERGY RENTS

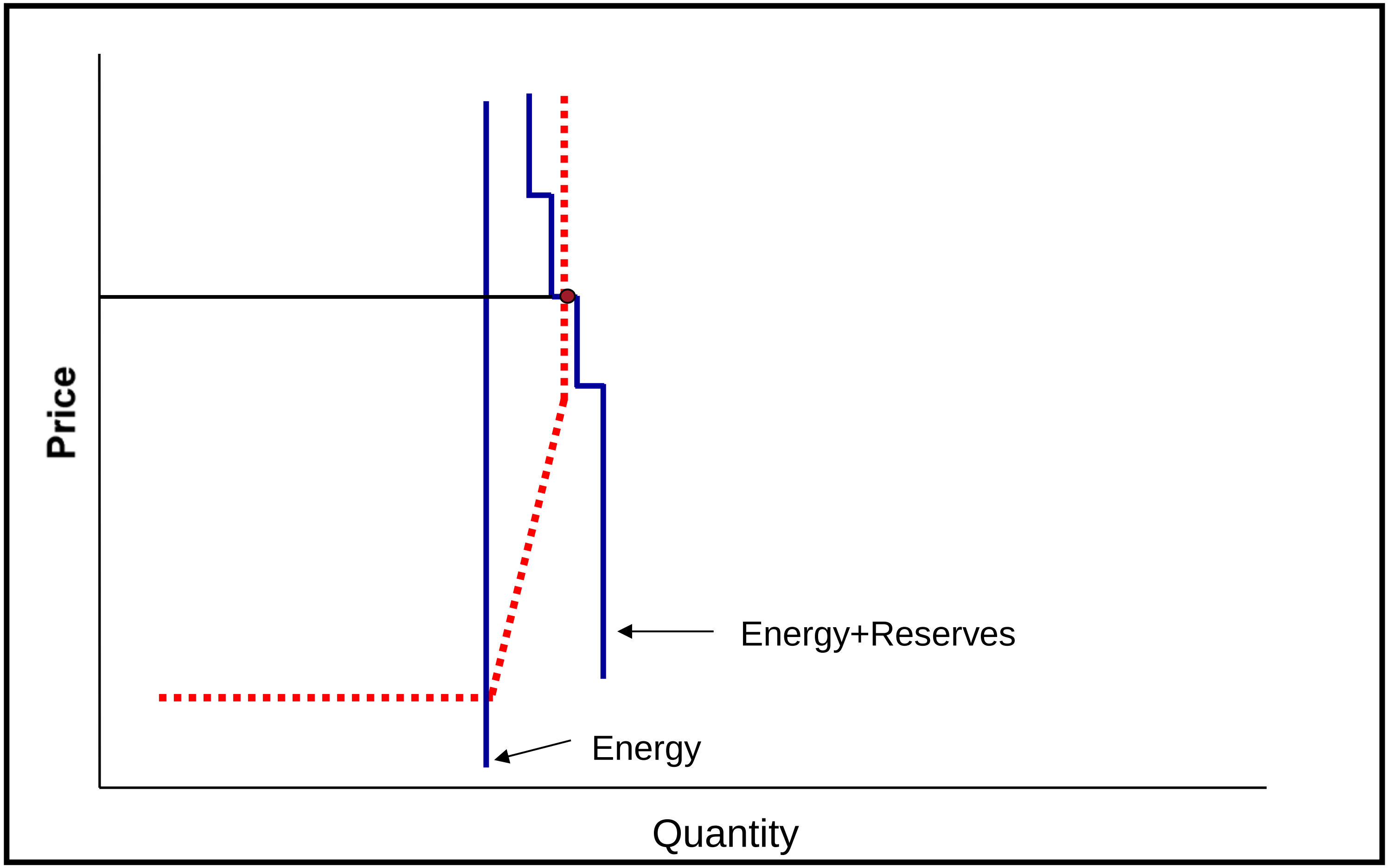
The formula currently calculates the peak energy adjustment using a 22,000 BTU/KWH heat rate and the higher of ultra low-sulfur # 2 oil in the New York Harbor plus a 7% adjustment for transportation on the day-ahead gas price at the Algonquin City Gate.

- When oil prices remained considerably above gas prices, this formula did not provide much constraint on the peak energy rent earned by gas-fired generators.
- In fact, no hour had a positive adjustment for more than a year after the change was made, but small charges began again in February 2013.[1]
- ISO New England filed on March 6, 2015 to eliminate the PER deduction beginning in FCA 10, the 2019-2020 delivery year (docket ER15-1184), accepted by FERC effective May 15, 2015.

1. Sec ISO New England Inc., Internal Market Monitor, "2014 Annual Markets Report," p. 75. Because the PER adjustment is calculated on a 12 month rolling average basis, it continued to impose losses on oil fired generators through November 2011.

D. Hybrid Energy Shortage and Capacity Markets

Original NYISO Reserve Demand Curve



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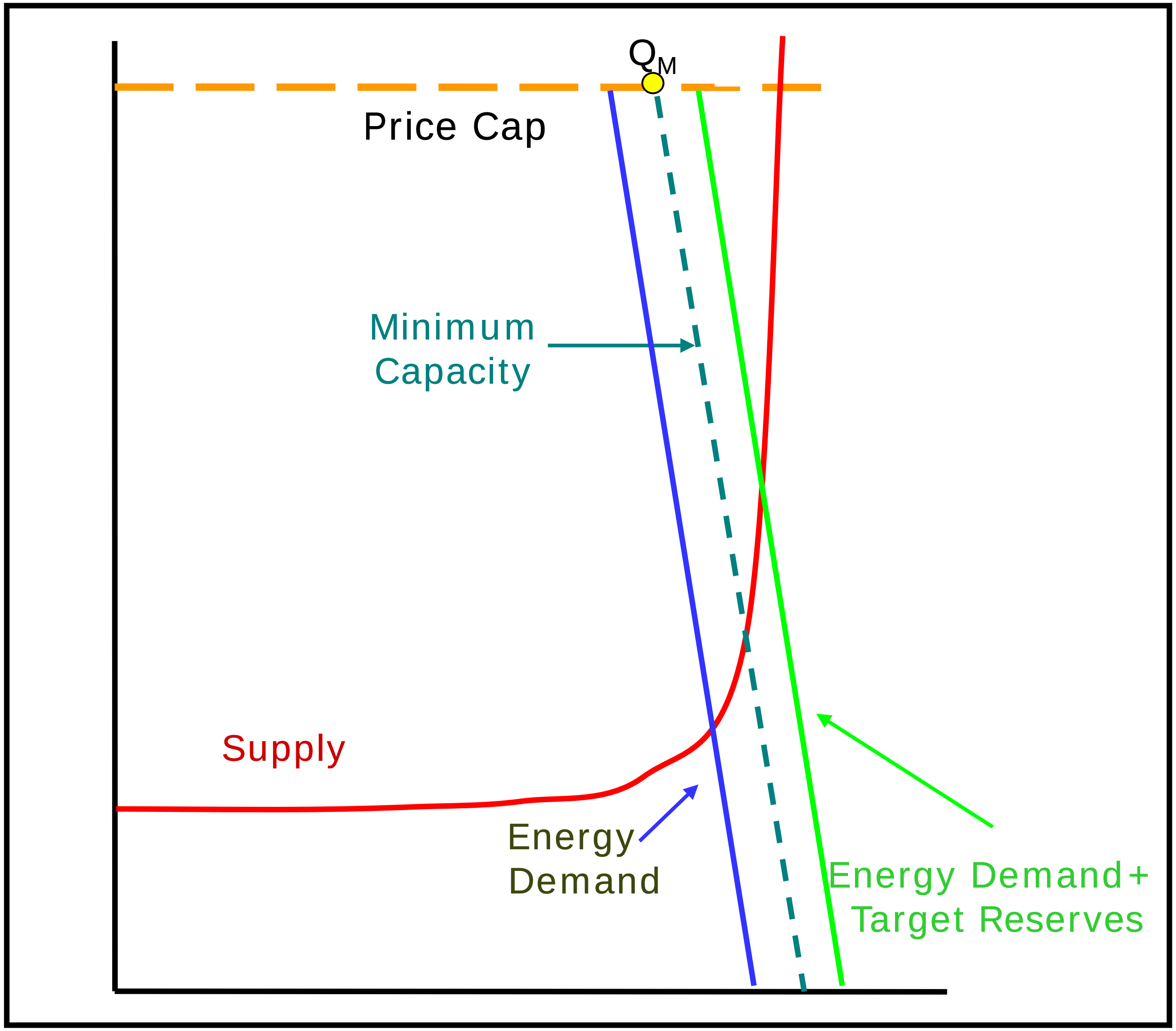
ALTERNATIVES NYISO

Some of the limitations of existing capacity markets systems can be addressed by increasing the importance of energy market revenues, without moving to an energy-only market design.

- Many of the recent changes in NYISO energy markets to improve shortage pricing provide incentives for suppliers to perform when it is really important from a reliability perspective.
- Increased energy market revenues for marginal suppliers should reduce the capacity price.

These changes do not address what may be the critical factor in assuring resource adequacy, however, long-term contracts for either energy or capacity.

Energy Pricing with Price-Responsive Load



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ALTERNATIVES — Demand Response

It is often implied that all capacity market and shortage pricing issues would be resolved if only there were more price responsive load in real time.

- More price-responsive load in real time could improve reliability as the market would clear even when there ws unusually high load conditions or unexpected generation outages.
- More price-responsive load would not solve the economic problem that drives the need for either capacity markets or high energy market shortage prices; prices would have to be high enough often enough for the marginal unit to recover its going-forward costs.
- Price-responsive load cleared the California gas market in 2000-2001 and the New England gas market in 2004. The market cleared, but prices were high, very high.

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