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MARGINAL SUCCESS

Capacity markets in the US, designed to spur investment in the peakload capacity needed to keep the lights on, have so far achieved their aim – but that doesn't mean there aren't plenty of people keen to change them.

As they approach their 10-year anniversary, capacity markets in the United States are facing an overhaul in how they are structured, with implications for how power plants are built and financed and what products – or range of products – will be available to the grid.

For a variety of reasons, mostly political and regulatory reasons, capacity markets in the US are localized in the northeastern quarter of the country. That makes the region a showcase for deregulated markets both in terms of how well they have performed and the challenges they face.

As deregulation took hold in the US in the late 1990s, more and more power was traded in wholesale markets. But stakeholders began to realize that there was a problem, the missing money problem.

Economically there are two types of electricity. Energy is bought and sold in real time, and provides revenues to pay for existing power plants, but those revenues are not sufficient to attract the investment necessary to build a power plant that might not run very frequently. Those plants, even though they may not run frequently, are critical to the operation of the power grid. They have to be there to meet peak demand, and spare capacity is needed to ensure reliability, which is measured by a system's reserve margin. The problem is how to pay for those plants.

Capacity markets were created to solve that problem, that is, to provide the missing money.

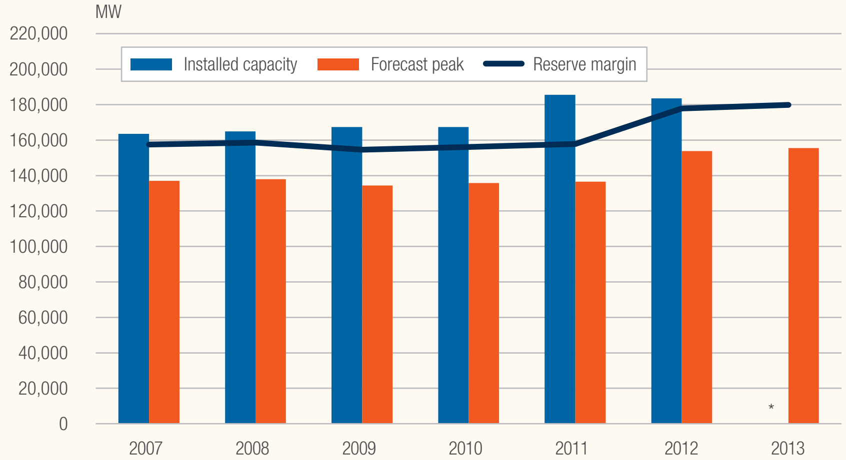
Ten years out, capacity markets appear to have done a good job in fulfilling their primary task. The lights have stayed on, and all four northeastern wholesale markets – ISO-New England, New York ISO, PJM Interconnection (which coordinates power transmission in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia) and the Midcontinent Independent System Operator (which covers all or part of Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Michigan, Ohio, Indiana, Illinois, Iowa and Nebraska, as well as Manitoba in ▶

Canada – enjoy robust reserve margins (see table PJM Reserves).

According to the North American Electric Reliability Corp.'s 2013 Summer Reliability report, PJM's mandated reserve requirement for the 2013-14 planning period is 15.9%, but the anticipated reserve margin is well above that at 29.3% (see NERC Summer Reliability Report).

ISO-NE's NERC reference reserve margin is 15%, and the region's anticipated reserve margin is 21.6%. NERC's reference reserve margin for NYISO is 17% while the anticipated reserve margin is 18.8%. And MISO's reserve requirement for 2013-14 is 14.2%. Its anticipated reserve margin is 18.8%.

PJM RESERVES



*PJM installed capacity numbers for 2013 not announced until 2014.

Source: PJM Interconnection

NERC SUMMER RELIABILITY REPORT

	NYISO	MISO	PJM	ISO-NE
Projected internal demand (MW)	33,279	91,532	145,029	26,690
Anticipated resources (MW)	39,592	108,742	187,531	32,458
Anticpated reserve (%)	18.8	18.8	29.3	21.6
NERC reference reserve (%)	17	14.2	15.9	15

Source: North American Electric Reliability Corp.

In a recently published report, "Capacity Markets, Lesson Learned from the First Decade," Brattle Group concluded that capacity markets have met their reliability mandate, but with a caveat. The success should not be "overstated," the authors wrote since those capacity markets were all instituted at times of surplus capacity.

'Version of socialism'

Despite the apparent successes, capacity markets have come under frequent and vocal criticism, particularly from power generators and from developers of power projects, for not sending price signals sufficient to encourage new investments.

"I believe that there are significant and fundamental flaws in the process," Anthony Alexander, president and CEO of FirstEnergy, recently said, referring to the capacity auction in PJM where his company operates.

Nick Akins, president and CEO of American Electric Power, one of the largest US utilities, was even stronger in his criticism. "AEP has issues with this regulatory construct we sometimes call a capacity market in PJM."

He went on to call the capacity market construct a "version of socialism" and said the "rules seem to penalize long-term investors."

And Kenneth Cornew, executive vice president and chief commercial officer of Exelon, said the low level of prices in PJM's last capacity auction are not reflective of the long-term capacity revenues needed to support new generation development.

Despite those criticisms, developers are stepping up to build new power plants. PJM Interconnection and ISO-NE both saw spikes in the amount of new generation that was offered and cleared in their most recent capacity auctions (see New Generation Added).

PJM's last capacity auction saw a record level of new generation clear, 5,463 MW, a jump of more than 100 MW above the 5,346 MW that cleared its previous auction. And new generation in ISO-NE spiked to 800 MW, from 79 MW in its previous auction.

The new projects were proposed despite low clearing prices for capacity in the auction, particularly in PJM, which saw prices dip to their lowest levels in three years (see PJM Prices).

And while the low prices may have disappointed incumbent generators in those ISO regions, they obviously did not deter investment by some developers.

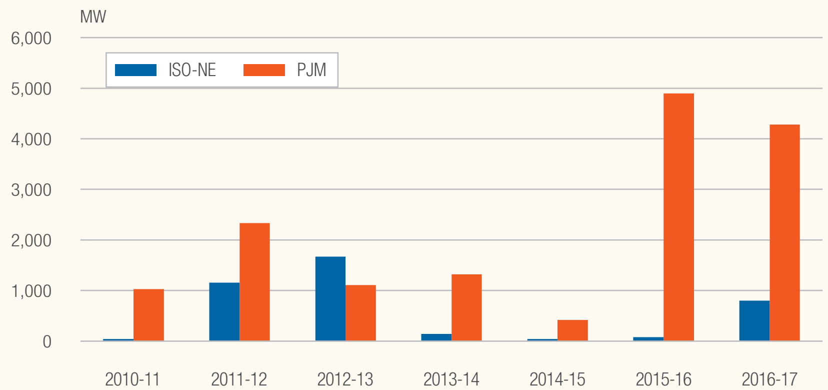
The low prices also reflect bids from capacity resources that have raised concerns from stakeholders.

In particular stakeholders are concerned about state subsidies and imports.

New Jersey and Maryland were concerned that residents of their states were paying too much for electricity from PJM and that the capacity auctions were not encouraging the in-state investments that would drive down prices, so they passed laws instituting solicitations that gave contracts to new in-state power projects. The move created fireworks among PJM stakeholders because the contracts were tied to the ISO's capacity markets, putting downward pressure on capacity prices.

Through a series of regulatory interventions PJM adjusted the rules to

NEW GENERATION ADDED



Source: PJM Interconnection, ISO-New England

its capacity market, but three projects – two in New Jersey and one in Maryland – still cleared the capacity auction. Contracts awarded to those projects have since been voided in decisions by two separate federal courts.

There are also tensions on the western side of PJM, which borders the Midcontinent ISO. Unlike PJM, MISO's capacity market is voluntary, and that is reflected in the prices.

MISO's most recent capacity auction closed in April at $1.05/MW-day. In May PJM's capacity auction cleared at $59.37/MW-day. The disparity in capacity prices has prompted generators in MISO to sell their capacity into PJM, pushing down prices. That has raised concerns among PJM stakeholders and administrators, who are now looking at imposing a cap on imports.

In both instances, the imports and the state subsidies, PJM's capacity market sent price signals – just not the new-build signals originally envisioned.

Capacity markets have also proved useful at providing a signal to generators debating whether or not to ▶

continue running older plants, especially coal-fired plants that are facing tighter emissions controls.

> "PJM's capacity market sent price signals – just not the new-build signals originally envisioned."

FirstEnergy in July cited capacity prices when it announced the close of two more coal plants in PJM, the 1,710-MW Hatfield Ferry station and the 370-MW Mitchell plant, both in Pennsylvania.

At the time of the announcement, UBS analyst Julien Dumoulin-Smith said FirstEnergy's announcement marked part of a "second wave" of coal plant "capitulations" in PJM. He cited the 10 GW of coal capacity that bid into PJM's 2016-17 BRA but did not clear, and said he would not be surprised to see further retirements.

In New England, NRG Energy in May cited low capacity prices in the decision to close its 352-MW, gas- and oil-fired Norwalk Harbor plant in Connecticut.

An analysis of data collected by the Federal Energy Regulatory Commission and compiled by Platts shows that Norwalk Harbor received $2.83 million in capacity payments, $4.19 million in energy payments and operated at a 2.7% capacity factor in the first quarter.

The data also shows at least a dozen plants with even lower capacity factors. And nearly all those plants had a higher proportion of revenues from capacity payments than from energy payments compared with NRG's Norwalk Harbor facility. In the first quarter, capacity payments accounted for 40% of Norwalk Harbor's $7 million in total revenue.

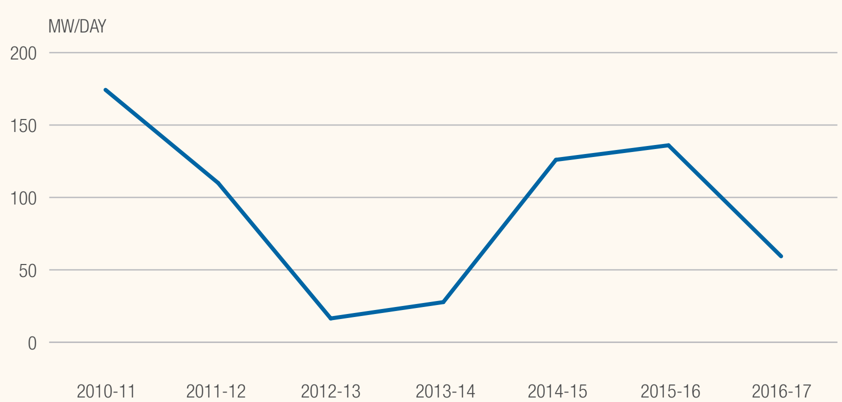
Dumoulin-Smith estimates that low capacity prices – exacerbated by the FERC mandated removal of ISO-NE's capacity floor price in the next auction – could force another 6 GW of mostly oil-fired capacity out of the market.

These issues – capacity imports, state level subsidies, low capacity prices – have been a source of contention for stakeholders in various ISOs. They also reflect the changing nature of capacity markets. They have become broader in scope than when they were first created.

Originally they were designed to encourage new generation, but to accommodate regulatory mandates, demand response now participates on an equal footing with generation.

Demand response is the opposite of generation. It turns off machines

PJM PRICES



Source: PJM Interconnection

during times of peak load to reduce the need for high priced peaking power. Such "load shaving" also shaves potential revenues from generators, but it provides revenues for curtailment service providers that contract with end-users to provide the service.

The incorporation of DR into capacity markets, particularly in New York, New England and PJM, has also added to the complexity of the capacity markets and has increased the level of administrative intervention.

One of the hot topics under discussion in PJM now is whether or not DR providers are bidding and clearing in the annual capacity auction, which looks out to a delivery period three years in the future, and then buying out their obligation more cheaply in the intervening auctions.

Critics charge that such actions are a misuse of the process, which they say is designed as a form of true-up for physical assets, not a means of arbitrage for financial players.

The issue has risen to the level where PJM is re-examining how it dispatches DR in its queue.

Against this background the Federal Energy Regulatory Commission on September 24 convened a technical conference to address the range of issues that have cropped up in individual capacity markets and the inconsistencies that exist in capacity markets across the four ISOs.

After a day of sometimes contentious testimony, FERC is now weighing improvements to the markets as some stakeholders call for further measures to address specific concerns.

While FERC is not necessarily looking to overhaul capacity markets as they now exist, some of the proposals that were presented at the meeting were, at least in the arcane world of capacity markets, somewhat radical.

In one presentation at the September 25 meeting James Wilson of Wilson Energy Economics said that experience has shown that new merchant plants are not being bid in at their costs. That was the expectation, and those bids were supposed to send a long-term price signal. But that has not happened, Wilson said.

He argued that many of the expectations of the capacity markets are, in fact, "inside out."

As an alternative to the current arrangement, Wilson and other presenters at the meeting advocated a more modest role for capacity markets. They say that many of the challenges that capacity markets are going to face as a wider array of resources enter the market – such as demand response and wind and solar power resources – would be better served through the energy and ancillary services markets, with capacity markets playing a diminished role.

Time will tell how those ideas are received and, if they are, how they will be implemented. Meanwhile capacity markets will have to deal with their success, which has resulted in a much wider array of resources entering into the market and low prices. ■

HOW CAPACITY MARKETS WORK

Capacity markets were designed to provide the financial incentives for building power generation capacity that might be used infrequently and could not survive on real time energy payments only.

Capacity auctions are operated by the wholesale markets that also operate the real time and day ahead energy markets, but capacity auctions are run separately by those wholesale markets, known either as independent system operators (ISOs) or regional transmission organizations (RTOs). Capacity auctions also have several features that make them very different to the real time and day ahead markets.

In the US there are organized capacity markets in four ISOs: the PJM Interconnection; the New York ISO; ISO-New England and the Midcontinent ISO.

There are big differences between how the ISOs conduct capacity auctions, but in broad strokes existing generation and/or proposed new generation must bid into the auction. They provide the supply side of auction. The ISO administrators provide the demand side by coming up with forecasts of demand and calculating how much capacity their systems will need to meet that demand, and to be sure there is a cushion to meet unforeseen events.

The administrators order the supply resource bids in order from high to low and select enough capacity to meet their forecast need and to maintain their reserve margins. In most auctions the marginal units set the price. So all bidders are paid the price of the last bid selected.

As mentioned, the various ISOs differ in how they have organized their capacity auctions. PJM for instance conducts its capacity auctions every spring for a delivery year three years in the future. ISO-New England's capacity auction also looks three years out, but the capacity auctions in MISO and New York are shorter term, two months and six months, respectively.

All bids selected in that auction receive payments for that delivery year. In return, they are expected to be available to generate power when needed, for instance, if there is an unexpected outage of another generator, or weather conditions create a spike in demand.