10:00 a.m. (EST)
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Energy Committee
May 26, 2016

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2016 Energy Committee Calendar
Meetings will begin at 10:00 a.m.

Thursday, May 26, 2016
Thursday, August 25, 2016
Thursday, November 17, 2016

OMA Energy Committee Meeting Sponsor:

scioto energy

OMA Energy Committee Agenda
May 26, 2016

Welcome and Introductions	Brad Belden, Belden Brick, Chair Jeff Klusty, Ariel Plant Manager, Host
State Public Policy Report	Ryan Augsburger, OMA Staff
Customer-Sited Resources Report • Energy efficiency program updates • EE Peer Network activity • PJM Study on competitive markets • Efficiency & renewable standards legislation	John Seryak, PE, RunnerStone, LLC
Counsel's Report • Subsidy Cases (Formerly PPAs) • FERC and US Supreme Court • FES "polar vortex" charges • AEP transmission charges	Kim Bojko, Carpenter Lipps & Leland Ryan O'Rourke, Carpenter Lipps & Leland
Presentations / Updates / New Business • Electricity Market Trends • Natural Gas Market Trends	Susanne Buckley, Scioto Energy Richard Ricks, NiSource, Columbia Gas of Ohio
Lunch	

Meeting sponsored by:

scioto energy

To: OMA Energy Committee
From: Ryan Augsburger
Re: Energy Public Policy Report
Date: May 26, 2016

Overview
2016 is a presidential election year, as such a relatively light legislative agenda is forecast. During the spring term, legislation to revise the frozen alternative energy standards was considered. Lawmakers heard plenty of concern from customer groups, including the OMA, about the PPA rate cases. At the same time they heard from utility advocates posturing for the PPAs or some other form of "regulation" that would surely deliver more profits and less competition to the monopoly utility distribution companies. The U.S. Supreme Court, The Ohio Supreme Court and the FERC also took actions that will notably impact the Ohio utility applications. In short, there is a lot in play!

Utilities Seek Nearly $6 Billion in Customer Subsidies PPA
Significant utility rate cases are pending at PUCO. Distribution utilities FirstEnergy, AEP and DP&L filed cases proposing affiliate power purchase agreements (PPAs) whereby the utility companies impose billions of dollars of new charges on customers to subsidize "uneconomic" generation owned by their affiliate generation company. The PUCO staff supported the proposals (after they opposed the proposals) and then in late March, the five governor-appointed PUCO commissioners voted unanimously to approve the AEP and FirstEnergy subsidy proposals.

Joining the official OMA litigation were dozens of leading Ohio manufacturers who individually communicated concerns on record to the PUCO imploring the agency to consider the significant costs without benefit. The PPA settlements also allowed for manipulation of the market for electricity that has been working. The latter concerns were echoed in a complaint filed at the Federal Energy Regulatory Commission (FERC) by the competitive suppliers of electricity as well as PJM interconnection, the operator of the grid and the market for Ohio. Several notable parties, including the OMA, intervened in the FERC complaint in support of the competitive supplier's complaint. In an expedited decision the FERC unanimously rescinded a waiver enjoyed by the Ohio utilities, in effect blocking the Ohio approved PPA provisions from going into effect without significant scrutiny and approval for the federal agency charged with protecting the regional market for electricity.

Reactions from AEP and FirstEnergy have been different. Shortly after the FERC ruling, AEP announced they would largely withdraw the PPA provisions and would lobby the Ohio government to "repeal Senate Bill 221 and re-regulate electric generation." Days later, AEP filed a significantly scaled back modification of the prior application. Even more recently AEP filed to extend the terms of the current rate plan.

FirstEnergy on the other hand has modified their prior PPA plan so that all references to the term "PPA" are absent and customer cash would flow to the utility not the deregulated generation affiliate, hoping the modification would clear FERC scrutiny. Ohio State University economist Dr. Edward "Ned" Hill dubbed the FirstEnergy modifications as the "synthetic PPA."

At this point all eyes are back on the PUCO to see their next move. The OMA Energy Group directs the OMA legal team strategy and has been quite busy this quarter. Many of the below listed developments have bearing on these cases.

"Reregulation"
With AEP and FirstEnergy's requests for affiliate PPAs stymied, at least one of the company's is calling for reregulation. In 1999, with the passage of Senate Bill 3, Ohio became a state in transition to deregulated generation. That transition which has taken over decade, has delivered customer choice, cost-savings and innovation. One of the main tenets of deregulation was forcing then-integrated utility companies to sell or spin-off their generation. "Stranded costs" and other above-market surcharge constructs enabled the utilities to have their generation paid for by Ohio's for a second time. If approved in some form, the PPA cases would have represented yet another above-market payment to utilities by customers who realize little to no benefit.

The OMA has been an ardent proponent of markets, supporting the original deregulation legislation and opposing utility profit subsidy schemes that distort the market and result in huge new above-market charges on manufacturers.

Several noteworthy studies have demonstrated how the market delivers lower prices, choice and innovation without compromising reliability. See the enclosed study commissioned by PJM.

In short, it is hard to know how or why Ohio government officials would want to spend any time considering this anti-market notion.

Legal Considerations to PPA Proposals
Over the past quarter the U.S. Supreme Court ruled 8-0 in the Maryland case. The Maryland case had parallels to the Ohio utility proposals. Summaries are available. The 8-0 ruling upholding FERC may have emboldened the FERC in the Ohio complaint.

Summaries are also included in the FERC complaint case ruling. The OMA intervention in the FERC case is included in meeting materials.

While all this was happening, the Ohio Supreme Court rendered two very good decisions that address customer issues. See counsel's report.

Clean Power Plan / Federal Greenhouse Gas Regulations / 111(d)
US EPA issued a final rule in early August. The OMA filed comment together with the NAM and individually. Ohio EPA and the PUCO filed comment on behalf of the state as did the Ohio attorney general. The gist of the testimony: as proposed, 111(d) revisions are unworkable. Litigation on the rule is expected to delay effectiveness. If the provision goes into effect, states will need to adopt "state implementation plans" that will impose regulations on emissions to attain the federal goals. Ohio regulators intend to seek extension. The OMA is conducting research on the many ramifications of the CPP.

The US Supreme Court recently granted the stay requested in the Attorneys General lawsuit meaning that implementation steps will dependent upon legal finding. Early this year, the OMA joined with the National Association of Manufacturers and the U.S. Chamber in filing an amicus brief to highlight economic concerns with the Plan. Many legal scholars believe that the passing of Justice Scalia portends survival of the Clean Power Plan.

Natural Gas Infrastructure
The OMA has expressed public support for the Rover Pipeline and Nexus Pipeline. Billions of dollars of pipeline investment are underway by several different developers. Additionally the OMA has participated in discussions with JobsOhio and representatives of America Natural Gas Alliance to consider measures to spur industrial delivery off new transmission investments. Research recently conducted by Cleveland State University may be helpful in this vein. Natural gas production continues to grow in the Buckeye state even with depressed pricing. Officials at JobsOhio have revisited their desire to advance the issue.

Transmission Charge Increase
Ratepayers within the AEP-Ohio service territory may have noticed a jump in on their electricity bills beginning last summer. The increase is attributed to a new rider called the Basic Transmission Cost Rider (BTCR) that went into effect on June 1, 2015.

While lawyers for the OMA Energy Group contested the new rider, it was ultimately approved by the PUCO. Since the implementation of the new rider in June, some members (specifically, AEP-Ohio GS-2 and GS-3 customers) have seen a significant increase in their transmission costs.

Polar Vortex *Pass-Through* Charges
Generation customers of First Energy Solutions (FES) were notified by the provider that they would be billed for a regulatory event associated with the polar vortex power shortages in January 2014. The one-time charge is outside the terms of the contract. If allowed by regulators, the charges would result in an unfavorable precedent for all customers. Several OMA members are working collectively to contest the charges. See counsel's report for positive developments in the case.

Energy Efficiency Legislation
Legislation was enacted in 2014 to revise Ohio's energy standards which required utilities to deliver a certain amount of efficiency from customers and to procure a certain amount of renewable generation. The issue has been reported and discussed at OMA meetings for over three years.

SB 310 froze the alternative energy standards for two years and created a legislative study committee to assess the impacts of the standards. A report was issued in September recommending an indefinite freeze. Governor Kasich subsequently commented that indefinite freeze was unacceptable, and that he did not favor the existing standards either. Without legislative revision, the freeze is scheduled to lift the first of 2017. Senator Seitz has introduced SB 320 to revise some provisions and to extend the freeze for another three years. In contrast Representative Amstutz (#2 ranked member of the House) introduced HB 524 which makes the freeze more permanent. Hearings have been held on the bills in recent weeks. It is unclear if or when these bills may advance.

Meanwhile, AEP and FirstEnergy have addressed plans for future renewable and energy efficiency programs in their PPA settlements in spite of the uncertain governing statutes...a move that has angered some in the General Assembly. Now that the PPA settlements are in limbo, the AEP and DP&L have begun proceedings to again extend their current energy efficiency plan.

Manufactured Gas Plant Remediation Costs
No legislative activity to report. A decision by the Ohio Supreme Court is expected. A provision of the utility PPA settlements has ramifications on this type of cost-recovery.

kWh Tax Revisions?
Stalled legislative proposals to modify the tax revenue generated by power plants (via the tangible personal property tax) may be creeping into discussions to modify the kilowatt hour tax which is paid by customers. In contrast, the tangible personal property tax is paid by power plants. NO VISIBLE ACTION.

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Belden: The PUCO should not gamble with Ohio's future

By Bradley H. Belden

Posted Mar. 17, 2016 at 7:29 PM
Updated Mar 18, 2016 at 12:34 PM

For the last several months, we have been learning more and more about the requests before the Public Utilities Commission of Ohio (PUCO) for FirstEnergy and American Electric Power (AEP) to charge customers above-market rates for electricity generated by under-performing facilities. Experts estimate FirstEnergy and AEP customers will pay billions of dollars more over the eight-year life of the deal. That's not for electricity actually used; it's to subsidize their plants and guarantee profits for their shareholders.

Much of the opposition to these Power Purchase Agreements (PPAs) has focused on the impact the price increase will have on residential consumers. And that, of course, is a concern. But for manufacturers, the cost of electricity can be very significant.

We estimate that Belden Brick's share of the additional costs of this new rider to approach $1 million over the eight-year term of the agreement. The construction industry is still feeling the effects of the real estate collapse of several years ago, and our company is still struggling to turn a profit. Belden Brick did not have the government to turn to during this recent downturn. AEP and FirstEnergy should not have this option either after they successfully argued to deregulate their industry. We are still paying expensive "stability" riders related to the deregulation process.

Belden Brick has been in Canton since 1885. I am fortunate to be a member of the fifth generation of the Belden family to manage the company. We own and operate six plants in Tuscarawas County, and employ approximately 500 people in Ohio. We are the largest family-owned and operated brick company in the United States and the sixth largest manufacturer by production volume. We are proud to be a part of the business communities in Stark and Tuscarawas counties.

The markets for electricity in Ohio have been working to the benefit of consumers, but these proposed deals are a massive setback to the consumer-friendly efficiency of those markets.

The impact would surely be felt by our employees and shareholders. Since Ohio deregulated its utilities, we have been able to shop for the best price on electricity generation, and that has helped keep costs down. Meanwhile our costs on the distribution and transmission side continue to climb mainly due to non-bypassable riders, which is how the PPA would also be applied. Lower energy prices mean more money to invest back into the business, into employee salaries and our community. That's how the American free market works.

Deregulation has also attracted several electricity generators to invest in Ohio. For example, Advanced Power is building a state-of-the-art plant in nearby Carroll County that will be fueled by natural gas and generate enough electricity to power 700,000 homes. According to media reports, construction will cost $890 million. This is the kind of investment Ohio needs — and the kind of new generation that will hold down the cost of electricity for business and residential consumers.

Other energy companies have recently offered a counter to the AEP and FirstEnergy proposals that would save Ohio consumers billions of dollars over the next eight years, promote and protect Ohio jobs, aid in Ohio's compliance with the Clean Power Plan, and encourage consumer and business growth. Again, that's how competition is supposed to work.

Preserving manufacturing jobs is critical to Ohio and to our region's economy. We should be doing everything we can to make sure Ohio can compete with other states to attract and retain industrial companies that come with high-paying manufacturing jobs. Raising the cost of electricity strictly to guarantee the least economical power plants will definitely not help.

In testimony before the PUCO, the Ohio Manufacturers' Association Energy Group was represented by Edward W. Hill, professor of public affairs and city and regional planning at The Ohio State University's John Glenn College of Public Affairs and College of Engineering. Dr. Hill called AEP's proposal "a device for shifting substantial business risk off of the shoulders of stockholders and management and onto Ohio's retail electric customers."

He compared the proposal to "regulatory taxation" because losses incurred by operations at the plants are passed on to all electricity users within their Ohio service territory. "The PPA can best be described as gambling with a two-headed coin. The bet becomes 'heads I win and tails you lose.'"

Ohio manufacturers like Belden Brick will lose if the PPA is approved.

Belden is director of support services at The Belden Brick Company.

The Ohio Manufacturers' Association

FOR IMMEDIATE RELEASE
March 31, 2016

CONTACT
Eric Burkland, (614) 224-5111

OMA Responds to PUCO Approval of FirstEnergy and AEP Plans to Impose Billions of Dollars in New Costs on Electricity Consumers

PUCO-approved Power Purchase Agreement riders amount to a bailout for utilities' older, uncompetitive power plants, says the OMA, and will stifle competition, drive electricity costs up and harm manufacturing competitiveness

(Columbus, OH): Eric Burkland, president of The Ohio Manufacturers' Association (OMA), issued the following statement today commenting on the Public Utility Commission of Ohio's (PUCO) decision to approve Power Purchase Agreement (PPA) plans for FirstEnergy and American Electric Power (AEP):

> "Today's decision by the PUCO to approve requests from FirstEnergy and AEP to impose billions of dollars in new customer costs to fund the utilities' power purchase agreements with their deregulated affiliates is a setback for electricity consumers in Ohio. If implemented, the agreements will serve essentially as new taxes on families and businesses, which will become a drag on the state's economy.
>
> Non-bypassable new costs on consumers served by FirstEnergy and AEP come at a time when the competitive electricity marketplace has begun to mature and is producing benefits in cost savings and innovative, new products. Those benefits will be undermined with the implementation of the PPAs.
>
> By granting the utilities' request for billions of dollars of new customer charges to subsidize the continued operation of older, uneconomical generating plants, the PUCO has reversed the course set by the Ohio General Assembly dating back to the passage of Senate Bill 3 in 1999. Approval of these anti-competitive bailouts will harm Ohio's manufacturing competitiveness by adding unnecessary costs to customers' bills – with no commensurate benefits.
>
> Access to reliable, affordable power is essential for manufacturing competitiveness. Ohio manufacturers will pursue available legal appeals and engage the Ohio General Assembly on this vital issue."

# # #

The mission of The Ohio Manufacturers' Association is to protect and grow Ohio manufacturing.

Opinion

Editorial

Grid lock

On the campaign trail, John Kasich loves talking about all the progress Ohio has made since he became governor. But the five members of the Public Utilities Commission of Ohio, all picked by Kasich, have given the state, its citizens and businesses backward-looking, eight-year plans that disproportionately benefit two big utilities — Akron-based FirstEnergy and American Electric Power of Columbus — and don't do nearly enough to make Ohio energy-competitive for the future.

The plans will face a challenge before the Federal Energy Regulatory Commission and possibly at the Ohio Supreme Court or in federal court. Last December, we argued in an editorial headlined "Pull the plug" that the PUCO should nix this sweet deal for the utilities. Now, that duty will fall to others to protect the interests of all Ohioans.

The rate plans essentially lock in markets for power generated by FirstEnergy and AEP nuclear and coal-fired plants that have struggled to compete for a variety of reasons, including low natural gas prices. For their part, both AEP and FirstEnergy have argued that the power purchase agreements are necessary and will save consumers money in the long run. (That remains to be seen.) Some modifications to the utilities' initial requests, in areas requiring the utilities to submit plans to modernize the aging electricity grid, invest in more renewable power and provide greater assistance to low-income customers, represented improvement, though more can and should be done in those areas.

Even so, the plans still amount to a bailout for the utilities, as well as a transfer of business risk to electric users from the companies' stockholders and management, without doing enough to encourage a swifter transition to clean energy.

* The PUCO decision has been poorly received in most quarters. For instance, Eric Burkland, president of the Ohio Manufacturers' Association, said the plans will "impose billions of dollars in new customer costs to fund the utilities' power purchase agreements with their deregulated affiliates" and, if implemented, "will serve essentially as new taxes on families and businesses, which will become a drag on the state's economy."

From the perspective of the Office of the Ohio Consumers' Counsel, the PUCO rulings "continue an unwelcome trend of government intervention in competitive markets." Dick Munson, Midwest clean energy director of the Environmental Defense Fund, argues that subsidies for the coal and nuclear plants "will be a huge step backward for electric competition and grid modernization."

The PUCO's decisions mean Ohio's electricity market "will face more uncertainty for up to two years as the matter winds its way through courts and regulatory agencies," as Crain's reporter Dan Shingler noted in a story last week.

The state for too long has faced uncertainty about the direction of its energy policy. It's our hope that the courts and regulatory bodies that next take up these issues do so with greater balance than applied by the PUCO, and without propping up plants in a market long after competition otherwise would force them out.

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Politically connected utilities have outsized influence in Ohio: Thomas Suddes

In this May 20, 2015, file photo, Christian Vittorio, an American Electric Power transmission field coordinator, gives a tour of an AEP electrical transmission substation in Westerville, Ohio. After its recent decisions in favor of AEP and FirstEnergy Corp., the Public Utilities Commission of Ohio's politically skewed composition needs to be rethought, writes Thomas Suddes. *(John Minchillo, Associated Press, File, 2015)*

By Thomas Suddes, cleveland.com
Email the author | Follow on Twitter
on May 08, 2016 at 4:13 AM, updated May 09, 2016 at 9:59 AM

Utility rates, fracking, workers' compensation: Ultimately, state government referees or umpires rival demands on Ohioans' checkbooks, liberties and natural resources; or tries to address injuries; or aims to right wrongs.

For that to work, the refs or umpires in Columbus are supposed to see both sides, then reach decisions fair to the public interest as well as private interests.

Common sense, though, suggests it'd be dicey – in terms of fairness – if all the officials at the Ohio State-Michigan game were Michigan grads, or if a Browns-Steelers game were refereed only by Pittsburghers.

Which brings us to the Public Utilities Commission of Ohio, which is supposed to be sure that electric and gas companies charge Ohioans fair prices. Three of the five PUCO members are Republicans, though, a party that, all else equal, is friendly to big businesses, such as utilities.

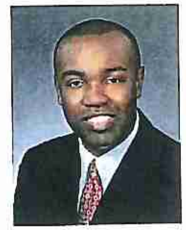
Given what goes on inside, "chiseled" is the perfect word, in more ways than one.

Rank-and-file Ohioans, regardless of politics, have to get by. And utility rates are a factor in making ends meet. Yet the Statehouse utilities lobby, along with lobbies representing banks, insurance companies, nursing home proprietors and oil-and-gas frackers, is among the most powerful in Columbus.

Utilities and other corporate giants will argue, and they're correct, that they're big employers – "job-creators," and all that. But they're also big political players – and not just out of civic-mindedness.

Four-term Republican Gov. James A. Rhodes is credited with the slogan, "Profit isn't a dirty word in Ohio." Today, those words might as well be chiseled on the outer walls of the Statehouse. (And given what goes on inside, "chiseled" is the perfect word, in more ways than one.)

A looming PUCO vacancy means Republican Gov. John Kasich will soon appoint a new PUCO member. True, given the five-member commission's seeming ... deference ... to FirstEnergy Corp. (the Illuminating, Ohio Edison and Toledo Edison companies) and American Electric Power Co. (the Ohio Power Co.), a new PUCO member likely wouldn't re-orient the panel, at least not much. Besides, anybody who might rock the boat wouldn't be picked.



PUCO Chairman Andre Porter has resigned

PUCO Chairman Andre Porter has given his resignation to Gov. John Kasich, effective at the close of business on Friday, May 20. Porter cited a job opportunity out of government as his reason for leaving.

Still, it's beyond ridiculous that none of the PUCO commissioners is a Democrat. Besides the three GOP incumbents (including Chairman Andre Porter, who's leaving the commission May 20, creating the vacancy Kasich will fill), two independents are PUCO members.

2015: Restore Public Utility Commission of Ohio's multiparty composition: editorial

A bill to restore political balance to the regulatory body that rules on how much Ohioans pay for utilities -- after recent appointments left the PUCO without a Democratic member for the first time in decades -- deserves speedy passage, writes the editorial board.

Ohio law forbids more than three of the five commissioners to belong to the same party but doesn't require at least one commissioner to be selected from each major party.

Ohio law *would* require that, if the General Assembly passed House Bill 122, sponsored by Rep. David Leland, a Columbus Democrat. But for some mysterious reason, even though HB 122's co-sponsors include a GOP conservative, Rep. Kristina Roegner, of Hudson, Leland's bill has moved about as far as an anvil pushed by an ant. Complete coincidence: Republicans, led by

Speaker Clifford A. Rosenberger of Clinton County's Clarksville, run the Ohio House 65-34, a bigger majority than any that the House's 20-year speaker, the late Scioto County Democrat Vernal G. Riffe, ever had. And the last time Democrats ran the state Senate was in 1984.

Ohio law creates a mechanism for a **nominating council** to recommend people for gubernatorial appointment to the PUCO. But Kasich, like previous governors of both parties, can pretty much appoint whomever he wants to the Public Utilities Commission. And he will.

PUCO appointments matter, because the commission is supposed to work out compromises between the competing interests of Ohio consumers and giant, politically connected utilities. If you don't know whether today's PUCO is doing that fairly, look at your next electric bill. That'll suggest an answer.

Thomas Suddes, a member of the editorial board, writes from Athens.

To reach Thomas Suddes: tsuddes@gmail.com, 216-999-4689

The Ohio Manufacturers' Association

FOR IMMEDIATE RELEASE
April 28, 2016

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OMA Responds to FERC Decision to Prohibit FirstEnergy and AEP from Implementing Plans to Impose Billions of Dollars in New Costs on Electricity Consumers

The Federal Energy Regulatory Committee (FERC) frustrates the Public Utilities Commission of Ohio's (PUCO) decision to grant subsidy requests from Ohio-based utilities AEP and FirstEnergy. Their bailout proposals would have forced Ohio customers to subsidize old, inefficient power plants for the next eight years at an estimated cost of $6 billion.

(Columbus, OH): Eric Burkland, president of The Ohio Manufacturers' Association (OMA), issued the following statement commenting on the FERC's decision to review Power Purchase Agreement (PPA) plans for FirstEnergy and American Electric Power (AEP) that had been recently approved by the PUCO:

"As did the U.S. Supreme Court in the Maryland case last week, FERC has acted to protect the wholesale electricity markets from manipulation, created by the recent PUCO decision on the PPAs, which harms customers.

The OMA strongly opposed the PUCO decision that harmed wholesale markets that are benefitting Ohio electricity consumers and that served to subsidize potentially uneconomic utility generating units.

The unanimous FERC decision is welcomed by Ohio manufacturers that depend on markets to provide the cost and innovation benefits of competition.

This decision provides an opportunity to reinforce the evolution of market-based electricity generation in Ohio and the economic benefits and job creation that will come from new investment in efficient generating capacity."

# # #

The mission of The Ohio Manufacturers' Association is to protect and grow Ohio manufacturing.

FERC's April Decision in the FE & AEP Cases

COLUMBUS BUSINESS FIRST

http://www.bizjournals.com/columbus/news/2016/04/28/frustrated-aep-ceo-ohio-should-reverse-energy.html?ana=e_colum_bn_breakingnews&u=NvNvzN9Z5mWcfl%2FESw6pmwo5ee00e3&t=1461855406&j=72751102

Frustrated AEP CEO: Ohio should reverse energy deregulation or we'll sell our plants; 'no interest' in prolonged debate with FERC

Tom Knox, Apr 28, 2016, 10:49am EDT

American Electric Power Company Inc. CEO Nick Akins is not hiding his frustration after federal regulators blocked the company's income-guarantee plan. The Columbus utility will lobby for re-regulating Ohio's energy market, he said, or it will sell the rest of its Ohio plants.

In other words, instead of fighting with the feds, AEP (NYSE:AEP) wants to blow up the Ohio power market as we've come to know it.

"I think AEP has reached the point where it's time to get this resolved once and for all," he said Thursday morning.

Last month the Public Utilities Commission of Ohio approved plans by AEP and FirstEnergy Corp. to have customers subsidize some of their Ohio power plants. The utilities said the "power purchase agreements" would save customers money in the long term and would keep the plants open and operating in Ohio under their control.

Late Wednesday, though, the Federal Energy Regulatory Commission threw a major wrench in AEP's plans by requiring the electric utilities to prove the plans won't force all Ohio ratepayers to subsidize their plants, even those who have opted for other suppliers in Ohio's electric choice program.
"While it is true that Ohio ratepayers will continue to have a statutory right to choose one retail supplier over another, we conclude, based on the record, that ... Ohio retail ratepayers are nonetheless captive in that they have no choice as to payment of the non-bypassable generation-related charges incurred under the affiliate PPA," FERC said in its ruling. "These non-bypassable charges present the 'potential for the inappropriate transfer of benefits from (captive) customers to the shareholders of the franchised public utility.'"

AEP responded strongly: It's not going to play along.

On an earnings call Thursday morning, Akins said the company has "no interest in getting involved in a protracted FERC jurisdictional debate." Instead, it will pursue a two-pronged approach:

AEP will begin trying to sell all its Ohio plants. The $16.5 billion utility always said this was an option if the PPAs weren't approved, and it is already looking to sell power plants in the state that weren't included in the proposals.

AEP will push for re-regulation in the Ohio legislature, including the repeal of Senate Bill 221, the 2008 bill that refined the state's deregulation of the energy market. This was often a rumored response to an AEP loss with the PUCO. Akins said legislators would have to move "very aggressively."

AEP could still challenge the FERC ruling and ultimately prevail but that's the third and most unlikely option.

"I think that's probably a longer hurdle at this point," Akins said.
A stock analyst asked Akins if the company has talked to legislators about reversing deregulation.

"I'm not going to address that," he said. "They're fully aware what the issues are. It's not a huge stretch for them to ask the question, 'We'll, why don't you just re-regulate?'"

Akins also said it might be simpler for ownership of the plants, now operated by an affiliate, to transfer back to AEP instead of pursuing full re-regulation. A transfer would need legislative and FERC review, but Akins said there is precedent for FERC approving such transfers.

AEP services 5 million customers in 11 states, most of them regulated. Utilities prefer regulation because of guaranteed returns, and AEP has zeroed in on improving and increasing its regulated transmission and distribution business – the infrastructure that helps get power to customers – while shedding its power plants in states like Ohio that have competitive marketplaces.

At AEP's annual shareholders event this week, before FERC's intervention, Akins said AEP is undergoing an "unprecedented transformation."

An analyst asked if AEP would work with other utilities to lobby the Statehouse. FirstEnergy's CEO has previously advocated for re-regulation. Akins said his company's interests align with others. Akron-based FirstEnergy (NYSE:FE) said it is evaluating its options, including seeking a FERC rehearing or letting FERC review it.

"It's always been our position that the PPA will satisfy the FERC's guidelines for an affiliate contract that benefits customers," spokesman Doug Colafella said in an email.

FirstEnergy abandons its 'power purchase agreements,' but not its plan for customers to pay more

By **John Funk, The Plain Dealer**
Follow on Twitter
on May 03, 2016 at 8:00 AM, updated May 03, 2016 at 11:09 PM

COLUMBUS, Ohio -- FirstEnergy now wants Ohio regulators to forget about the "power purchase agreements" they approved to save the company's old power plants -- but at the same time allow the company to keep the monthly customer surcharges that the PPAs were designed to produce.

In a move that appears to be a strategy to avoid federal review of the PPAs that U.S. **regulators demanded** last week, FirstEnergy filed a modified version of its rate plan late Monday with the Public Utilities Commission of Ohio.

Monday was the deadline for appeals in the case. The PUCO **approved the plan** March 31. Opposing power companies took their objections to the Federal Energy Regulatory Commission even before the PUCO ruled.

As now proposed, FirstEnergy's plan would eliminate the power purchase agreements between FirstEnergy's regulated local power delivery companies -- Ohio Edison, the Illuminating Co. and Toledo Edison -- and its unregulated FirstEnergy Solutions, which owns the power plants.

Yet the plan would keep the new charges the purchase agreements would have forced customers to pay. In other words, customers still would see their monthly bills increase under this revised plan.

The monthly surcharges now would not be based on constantly changing wholesale markets and what it costs for the company's old power plants to produce electricity as originally proposed. In fact, the charges would not be figured on actual costs at all.

Instead, the surcharges would be based on estimated power production costs that the company included in the original proposal it filed with the PUCO more than 18 months ago.

In short, there would be nothing for the Federal Energy Regulatory Commission to review in this modified plan. And therefore there would be nothing to impede the PUCO from quickly approving the modified plan, the company argued in its appeal.

FirstEnergy wants the new rate plan approved by May 25 -- and new rates and the surcharges -- in place by June 1. Once in place, the company can keep collecting the surcharges while opponents run through months or years of appeals.

In an explanation released after its filing at the PUCO, FirstEnergy reiterated its argument that the rate plan would "protect customers against longer term price increases and volatility."

"Customers would receive credits or charges on their monthly electric bills based on the projected plant cost calculations and electric output contained in the recently approved ... [rate plan]," the company said.

The FERC last week revoked a waiver of federal rules it had given FirstEnergy in 2008 allowing its unregulated FirstEnergy Solutions to sell electricity to the company's affiliated local delivery companies.

That waiver was conditional: FirstEnergy's customers were free to shop for better deals from competitors. And the intra-company sales were made through competitive biding among wholesalers vying to supply the Ohio companies.

The problem with the proposed power purchase agreements, the FERC noted in a ruling last Thursday, was that anybody whose power is delivered by a FirstEnergy company would have to pay the surcharge, even those customers buying power from competitors through retail contracts.

The FERC ruling knocked the legal foundation out from under the PPAs, though it left open the door for FirstEnergy to submit the agreements for federal review. The company in a separate letter to investors also released late Monday said it was "currently developing a response" to the FERC ruling, not due until May 27.

The PPAs have been at the heart of the company's proposed rate plan since it filed the plan application on Aug. 4, 2014.

As originally proposed, FirstEnergy's three traditional Ohio distribution companies were to have bought all of the output of the W.H. Sammis coal-fired power plant on the Ohio River and the Davis-Besse nuclear plant on Lake Erie near Toledo -- at whatever the power had cost to generate, plus a 10.38 percent profit.

The three delivery companies were to have then immediately bid the power into daily and hourly wholesale auctions run by PJM Interconnection, the non-profit company managing the high-voltage grid from Ohio to New Jersey.

The plan was that customers would make up the difference between the cost of the power and what it would fetch in the competitive markets now dominated by natural gas-fired power plants that can more cheaply generate power.

The company claimed that Sammis and Davis-Besse had a difficult time competing in wholesale markets against the new, gas-fired plants and that's why it needed the PPAs. Last week, however, FirstEnergy's top executives admitted during a conference with financial analysts that the two power plants **would be profitable this year**, even without the power purchase agreements.

As now proposed, the new plan would provide extra revenue to the Illuminating Co., Ohio Edison and Toledo Edison because they would not have to buy costly power from Sammis and Davis-Besse. The three delivery companies buy power with long-term contracts through PUCO-monitored competitive bidding over wholesale markets, a practice that has pushed power prices down.

FirstEnergy had argued that the extra monthly charges would become credits in future years when natural gas prices increased, making coal and nuclear power competitive again.

The company estimated the arrangement would cost Ohio customers as much as $363 million extra during its first 31 months. But over the eight-year term of the contracts, the deal was to have saved customers $560 million as wholesale prices rose and the two old plants became competitive once again.

The Ohio Consumers' Counsel, the Sierra Club and the Ohio Manufacturers' Association questioned that reasoning.

The Consumers' Counsel estimated the PPAs would have over eight years forced Ohio consumers to pay between $700 and $1,100 in extra charges.

"This continuing saga of the bailout remains a great risk for Ohioans' electric bills and, now approaching two years into the state process, an imposition on government regulation that the public funds. Enough is enough," Consumers' Counsel Bruce Weston said Tuesday.

The Sierra Club argued during the case that FirstEnergy's estimates of rising natural gas prices were too high and out-of-date, inflating its estimates of the amount of money the PPAs with Sammis and Davis-Besse would save over the eight-year rate plan.

Shannon Fisk, managing attorney at Earthjustice, a non-profit law firm representing the Sierra Club, slammed the company's strategy in a note released Monday night.

"FirstEnergy's latest gambit underscores that its bailout proposal has nothing to do with protecting customers or preserving Ohio generation, and everything to do with propping up corporate profits," he said.

In a letter to investors also released Monday evening, the company explained its strategy, writing that Monday's filing "further supports a strategic focus on regulated operations and better positions the Ohio Companies to preserve economic security for Ohio customers."

FirstEnergy's share price on the New York Stock Exchange this year has risen and fallen on investor expectations of the chances the PPAs would be approved.

The share price closed April 27 at $36.05, a high for this year, following the company's release of its quarterly financial results. The following day, the price dropped to $32.47 on news that the FERC had eliminated the legal foundation for the PPAs and ruled the company would have to submit them for review if the company intended to use them. The share price Tuesday jumped to $33.90 at the beginning of the day before sinking back toward $33.

Comments of Ohio Consumers' Counsel Bruce Weston have been added to this article.

The Ohio Manufacturers' Association

Threats to Ohio's Competitive Market for Electricity

Recent developments in Ohio's regulatory framework for electricity generation demonstrate the need for continued vigilance, analysis and advocacy by the OMA Energy Group (OMAEG) and manufacturers across Ohio.

What's all the fuss about?

On March 31, 2016, the Public Utilities Commission of Ohio (PUCO) approved proposals from FirstEnergy (FE) and American Electric Power (AEP) to create non-bypassable Power Purchase Agreement (PPA) riders. The PPAs would force all customers in each utility's service territory to pay a monthly charge to subsidize the continued operation of certain uneconomic generating facilities owned partially or wholly by the utilities or their regulated competitive generation affiliates. Customers would be forced to pay an extra charge on their monthly electric billsto providethe utilities guaranteed levels of profit from aging, uneconomic power plants – even when cheaper power is available and/or a customer purchases its generation service from an alternative supplier.

Expert witnesses found that over the next eight years, the PPAs could cost FE customers $3.9 billion and AEP customers $2 billion.

Multiple parties, including the OMAEG, supported a complaint concerning the PPAs to the Federal Energy Regulatory Commission (FERC). On April 27, 2016, in a victory for Ohio manufacturers, the FERC ruled that the FE and AEP PPAs would need to undergo additional federal review before they could be enacted. The purpose of the additional review would be to determine if enactment of the PPAs would result in "market abuse"from subjecting electricity customers to non-bypassable, above-market charges from the utilities' competitive affiliates.

Here we go again.

FE and AEP both have filed for rehearings of the PUCO decisions, but they have responded to the FERC ruling in markedly different ways.

Through what may be described as a kind of verbal sleight of hand, FE has proposeda new non-bypassable rider – what it calls a financial "hedging" mechanism– that its customers would, as in FE's original PPA proposal, be unable to avoid paying. Basically, FE is asking the PUCO to completely forget about the PPAs the utility had previously proposed to generate profits from otherwise unprofitable power plants – while also seeking PUCO approval of FE's request to collect the same additional monthly subsidy from its customers that the utility had proposed in its PPA.

Under FE's latest proposal, its customers would pay more when wholesale electricity prices are low; any credits that customers would have coming to them when wholesale prices are high would be paid by FE's regulated companies, which are paid by customers. In other words, customers would end up paying their credit to themselves with their own money.

In either case, the result is the same: an estimated $3.9 billion bailout of FirstEnergy.

AEP, on the other hand, has responded to the FERC ruling by abandoning its request for a non-bypassable PPA rider (with one small exception) associated with coal plants. Further, AEP indicated it may seek to sell its Ohio power plants or move "very aggressively" to seek re-regulation of the retail electric market via legislative action at the Ohio General Assembly. Additionally, AEP has reiterated its commitment to develop 500 MW of wind energy and 400 MW of solar energy, but with a few caveats related to the modifications made by the PUCO, including insisting that any cost-recovery rider for renewable energy projects must be non-bypassable and owned in part by AEP affiliates.

Why do the utilities want these subsidies?

The utilities increasingly have been painting doomsday scenarios for Ohio's energy future. They are dismissive of the role that PJM Interconnection plays as a regional transmission organization, arguing that PJM is not operating effectively and that Ohio would be better served by a more Ohio-centric position on electricity generation. They contend that if the state does not act soon to approve customer subsidization of certain obsolete, unprofitable power plants, these generation assets will be at risk of shutting down, in turn threatening theavailability and affordability of power for Ohio customers.

The truth, however, is something more fundamental.

As Ohio has slowly transitioned from a regulated environment for electricity to a competitive market for electricity generation, utilities have failed to adapt their business models accordingly so they are positioned to thrive in a competitive market. In the last quarter of the 21st-century, U.S. manufacturers were forced to dramatically reinvent their operations in order to survive the onslaught of globalization – and we continue to do so today.This also has been the case in other deregulated industries such as transportation, trucking, airlines,banking, telecommunicationsand others.

The time has come for Ohio's electric utilities to undertake their own transformation.

Why should manufacturers be concerned?

The OMA was one of the driving forces behind the first concerted effort to transition Ohio's retail electric market from regulation to competition, dating back to the passage of Senate Bill 3, Ohio's historic electric restructuring legislation, in 1999. That restructuring effort sought to secure safe, reliable, lowest-cost electricity for customers.

While the transition to "electric choice" has had its rocky moments, electricity customers in Ohio today enjoy unprecedented options for shopping for generation service. The competitive market is working. It's delivering customer choice, new energy technologies, innovative energy services, and direct energy savings to customers – all while assuring energy reliability.

Efforts by FE and AEP to secure non-bypassable customer subsidization of the utilities' uneconomic power plants put the benefits of electric choice at great risk. If FE and AEP are successful with the rehearings they have requested from the PUCO, electricity customers in Ohio can expect reduced ability to shop for the best available price and no option but to pay above-market prices for electricity whether they actually shop or not.

In continuing its opposition to the utilities' proposals to secure guaranteed profits for their uneconomic generation assets, the OMAEG is standing up to protect what has long been the engine of economic growth and strength in Ohio and the nation: American free enterprise. The utilities' efforts to add non-bypassable charges to the market-based price of power is the latest of repeated ploys by FE and AEP to try to mitigate the impact of their past poor business decisions and deny the benefits of free-market competition to customers in Ohio.More broadly, it also represents an ongoing strategy of the utilities to shift the financial risk associated with obsolete, uneconomic power plants from utility shareholders to utility customers.

For all of these reasons, the OMAEG remains committed to sustained opposition to FE's and AEP's petitions to the PUCO for rehearings. We ask that OMA member manufacturers join our effort. To find out more, contact Ryan Augsburger at raugsburger@ohiomfg.com or (800) 662-4463.

# # #

HB8 **OIL-GAS LAW** (HAGAN C) To revise provisions in the Oil and Gas Law governing unit operation, including requiring unit operation of land for which the Department of Transportation owns the mineral rights.
Current Status: 4/14/2015 - Senate Energy and Natural Resources, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-8

HB23 **OIL-GAS LEASE INCOME** (AMSTUTZ R) To use one-half of any income from oil and gas leases on state land to fund temporary income tax reductions, to modify the law governing the use of new Ohio use tax collections, and to require the Director of Budget and Management to recommend whether or not income tax rates should be permanently reduced.
Current Status: 11/18/2015 - Senate Ways and Means, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-23

HB64 **OPERATING BUDGET** (SMITH R) To make operating appropriations for the biennium beginning July 1, 2015, and ending June 30, 2017, and to provide authorization and conditions for the operation of state programs.
Current Status: 6/30/2015 - **SIGNED BY GOVERNOR**; eff. 6/30/15; certain provisions effective 9/29/2015, other dates
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-64

HB72 **ENERGY IMPROVEMENT DISTRICTS** (CONDITT M) To authorize port authorities to create energy special improvement districts for the purpose of developing and implementing plans for special energy improvement projects and to alter the law governing such districts that are governed by a nonprofit corporation.
Current Status: 5/6/2015 - **BILL AMENDED**, House Public Utilities, (Fourth Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-72

HB83 **OIL-GAS ROYALTY STATEMENT** (CERA J) To require the owner of an oil or gas well to provide a royalty statement to the holder of the royalty interest when the owner makes payment to the holder.
Current Status: 3/10/2015 - House Energy and Natural Resources, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-83

HB122 **PUBLIC UTILITIES COMMISSION MEMBERSHIP** (LELAND D) To require that each major political party be represented on the Public Utilities Commission, to specify that not more than three commissioners may belong to or be affiliated with the same major political party, and to require that Public Utilities Commission Nominating Council lists of nominees include individuals who, if selected, ensure that each major political party is represented on the Commission.
Current Status: 3/24/2015 - Referred to Committee House Government Accountability and Oversight
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-122

HB162 **SEVERANCE TAX RATES** (CERA J) To change the basis, rates, and revenue distribution of the severance tax on oil and gas, to create a grant program to encourage compressed natural gas as a motor vehicle fuel, to authorize an income tax credit for landowners holding an oil or gas royalty interest, and to exclude some oil and gas sale receipts from the commercial activity tax base.
Current Status: 5/12/2015 - House Ways and Means, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-162

HB176 **GAS-FUEL CONVERSION PROGRAM** (HALL D, O'BRIEN S) To create the Gaseous Fuel Vehicle Conversion Program, to allow a credit against the income or commercial activity tax for the purchase or conversion of an alternative fuel vehicle, to reduce the amount of sales tax due on the purchase or lease of a qualifying electric vehicle by up to $500, to apply the motor fuel tax to the distribution or sale of compressed natural gas, to authorize a temporary, partial motor fuel tax exemption for sales of compressed natural gas used as motor fuel, and to make an appropriation.
Current Status: 11/18/2015 - **REPORTED OUT**, House Finance, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-176

HB190 **WIND FARM SETBACKS-COUNTY** (BURKLEY T, BROWN T) To create an alternative wind farm setback in cases where a process has been initiated to interconnect the wind farm to a transmission system and the wind farm is in the Ohio wind corridor.
Current Status: 5/18/2016 - **SUBSTITUTE BILL ACCEPTED**, House Public Utilities, (Third Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-190

HB214 **PUBLIC IMPROVEMENT-PIPING MATERIAL** (THOMPSON A) To restrict when a public authority may preference a particular type of piping material for certain public improvements.
Current Status: 5/24/2016 - House Energy and Natural Resources, (Third Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-214

HB349 **STATE EMISSIONS PLAN** (SMITH R, GINTER T) To require the Environmental Protection Agency to submit a state plan governing carbon dioxide emissions to the General Assembly prior to submitting it to the United States Environmental Protection Agency, and to declare an emergency.
Current Status: 12/8/2015 - House Energy and Natural Resources, (Third Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-349

HB390 **NATURAL GAS-TAX EXEMPTION** (SCHAFFER T, RETHERFORD W) To exempt the sale of natural gas by a municipal gas company from the sales and use tax.
Current Status: 5/25/2016 - Senate Ways and Means, (Fifth Hearing)

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-390

HB472 **RENEWABLE-EFFICIENCY ENERGY REQUIREMENTS** (STRAHORN F) To unfreeze the requirements for renewable energy, energy efficiency, and peak demand reduction, to permit changes in and Public Utilities Commission action on electric distribution utility portfolio plans in 2016, to revise the setback requirement for economically significant wind farms, and to repeal the setback requirement for wind farms of fifty megawatts or more.
Current Status: 2/23/2016 - Referred to Committee House Public Utilities
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-472

HB473 **UTILITY SERVICE TAX-LEVY** (AMSTUTZ R) To require voter approval before a county may levy a new utilities services tax, to allow small businesses to count employees of related or affiliated entities towards satisfying the employment criteria of the business investment tax credit, to permit a bad debt refund for cigarette and tobacco product excise taxes paid when a purchaser fails to pay a dealer for the cigarettes or tobacco products and the unpaid amount is charged off as uncollectible by the dealer.
Current Status: 5/17/2016 - House Ways and Means, (Fourth Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-473

HB489 **MINE FUNDS** (CERA J) To credit a portion of the money derived from the Kilowatt-Hour Tax Receipts Fund to the Abandoned Mine Reclamation Fund, the Acid Mine Drainage Abatement and Treatment Fund, and the Mine Safety Fund and to make other changes to those funds.
Current Status: 5/10/2016 - House Ways and Means, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-489

HB515 **HEATING FUELS-SALES TAX** (PATTERSON J, CERA J) To exempt from sales and use taxation the bulk sale of firewood and certain other heating fuels, and to reimburse the Local Government Fund and Public Library Fund and county and transit sales tax collections for the resulting revenue losses.
Current Status: 4/26/2016 - Referred to Committee House Ways and Means
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-515

HB522 **INJECTION WELLS** (PHILLIPS D) To prohibit injection of brine and other waste substances except in class I injection wells, to prohibit the conversion of oil and gas wells, to require municipal or township approval prior to the issuance of an oil or gas well permit, and to levy a fee on the injection of brine and other waste substances into a class I injection well.
Current Status: 4/26/2016 - Referred to Committee House Energy and Natural Resources
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-522

HB540 **OIL-GAS WELL FUND REVENUE** (CERA J) To limit the amount of revenue that may be credited to the Oil and Gas Well Fund and to allocate funds in excess of that amount to local governments and fire departments.
Current Status: 5/17/2016 - Referred to Committee House Finance
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-540

HB541 **STATE AGENCY-CLEAN POWER PLAN** (LANDIS A) To prohibit any state agency from implementing the federal "Clean Power Plan."
Current Status: 5/4/2016 - Referred to Committee House Energy and Natural Resources
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-541

HB554 **RENEWABLE ENERGY REQUIREMENTS** (AMSTUTZ R) To revise the requirements for renewable energy, energy efficiency savings, and peak demand reduction and to revise provisions governing which customers can opt out of related programs.
Current Status: 5/11/2016 - House Public Utilities, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HB-554

HCR7 **TAX EXEMPT MUNICIPAL BONDS** (SPRAGUE R) To urge the President and the Congress of the United States to preserve the tax-exempt status of municipal bonds.
Current Status: 5/11/2016 - **ADOPTED BY SENATE;** Vote 33-0
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HCR-7

HCR9 **SUSTAINABLE ENERGY-ABUNDANCE PLAN** (BAKER N) To establish a sustainable energy-abundance plan for Ohio to meet future Ohio energy needs with affordable, abundant, and environmentally friendly energy.
Current Status: 6/17/2015 - **ADOPTED BY SENATE;** Vote 32-1
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-HCR-9

SB45 **LAKE ERIE SHORELINE IMPROVEMENT** (SKINDELL M, EKLUND J) To authorize the creation of a special improvement district to facilitate Lake Erie shoreline improvement.
Current Status: 3/17/2015 - Senate Energy and Natural Resources, (Second Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-45

SB46 **LAKE ERIE DRILLING BAN** (SKINDELL M) To ban the taking or removal of oil or natural gas from and under the bed of Lake Erie.
Current Status: 5/11/2016 - Senate Energy and Natural Resources, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-46

SB47 **DEEP WELL BRINE INJECTION PROHIBITION** (SKINDELL M) To prohibit land application and deep well injection of brine, to prohibit the conversion of wells, and to eliminate the injection fee that is levied under the Oil and Gas Law.
Current Status: 5/11/2016 - Senate Energy and Natural Resources, (First Hearing)
State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-47

SB58 **CONDITIONAL SEWAGE CONNECTION** (PETERSON B) To authorize a property owner whose property is served by a household sewage treatment system to elect not to connect to a private sewerage system, a county sewer, or a regional sewerage system under specified conditions.

Current Status: 3/4/2015 - Referred to Committee Senate Energy and Natural Resources

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-58

SB100 **SALES TAX HOLIDAY-ENERGY STAR** (BROWN E) To provide a three-day sales tax "holiday" each April during which sales of qualifying Energy Star products are exempt from sales and use taxes.

Current Status: 3/4/2015 - Referred to Committee Senate Ways and Means

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-100

SB120 **OIL-GAS LAW REVISION** (SCHIAVONI J) To revise enforcement of the Oil and Gas Law, including increasing criminal penalties and requiring revocation of permits for violations of that Law relating to improper disposal of brine.

Current Status: 3/10/2015 - Referred to Committee Senate Energy and Natural Resources

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-120

SB164 **UTILITY SMART METER CONSENT** (JORDAN K) To require electric distribution utilities to obtain a customer's consent prior to installing a smart meter on the customer's property

Current Status: 5/27/2015 - Referred to Committee Senate Public Utilities

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-164

SB166 **HORIZONTAL WELL EMERGENCY PLAN** (GENTILE L) To require the owner of a horizontal well to develop and implement an emergency response plan for the purpose of responding to emergencies.

Current Status: 10/7/2015 - Senate Energy and Natural Resources, (First Hearing)

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-166

SB185 **SPECIAL IMPROVEMENT DISTRICTS** (SEITZ B) To revise the law governing special improvement districts created for the purpose of developing and implementing plans for special energy improvement projects.

Current Status: 5/17/2016 - Senate Energy and Natural Resources, (Fifth Hearing)

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-185

SB320 **RENEWABLE ENERGY** (SEITZ B) To revise the requirements for renewable energy, energy efficiency, and peak demand reduction, to permit property owners to petition municipal corporations and townships for the purpose of developing and implementing special energy improvement projects.

Current Status: 5/11/2016 - Senate Energy and Natural Resources, (First Hearing)

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-320

SB325 **ELECTRICAL DISTRIBUTION-RENEWABLE REQUIREMENT** (JORDAN K) To repeal the requirement that electric distribution utilities and electric services companies provide 12.5% of their retail power supplies from qualifying renewable energy resources by 2027.

Current Status: 5/4/2016 - Referred to Committee Senate Energy and Natural Resources

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-325

SB327 **OIL-GAS LAW REVISION** (BALDERSON T) To revise provisions in the Oil and Gas Law governing unit operation and to specify that the discounted cash flow formula used to value certain producing oil and gas reserves for property tax purposes is the only method for valuing all oil and gas reserves.

Current Status: 5/11/2016 - Referred to Committee Senate State and Local Government

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SB-327

SCR6 **EXPORT-CRUDE OIL** (BALDERSON T) The urge the U.S. Congress to lift the prohibition on the export of crude oil from the United States.

Current Status: 12/8/2015 - **ADOPTED BY HOUSE**; Vote 67-24

State Bill Page: https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA131-SCR-6

Energy

OMA Defends Public Benefit of Pipelines

May 20, 2016

Together with other business interests, the OMA filed an amicus brief in a case now pending before the Ohio Seventh District Court of Appeals, in Youngstown. The OMA urges the Court of Appeals to uphold the ruling of a Harrison County trial court in the case, *Sunoco Pipeline v.Carol A. Teter, Trustee.*

At issue is when a pipeline developer may invoke Ohio's eminent domain statute to site the pipeline. Landowners have challenged Sunoco's authority to use eminent domain to construct the Mariner East 2 project which will deliver natural gas liquids from the Marcellus and Utica shale in Ohio to points eastward.

The OMA recognizes that pipelines are the safest, most reliable and cost effective means of transporting petroleum and petroleum products, which contributes to reliable and low-cost energy and raw materials for manufacturers.

AEP Seeks to Extend Rate Plan Until 2024

May 20, 2016

On May 13, AEP filed to extend its current rate plan, asking regulators for approval by September. The extension request is a component of a broader set of applications requested by AEP with modifications following FERC's move to block approval of the power purchase agreement cases in late April.

The plan would establish permissible utility charges through 2024 and would add some new riders that the utility can use to fund programs and subsidize certain customers. Customers cannot avoid non-bypassable charges by shopping.

Read more in this Columbus Dispatch story by Dan Gearino.

PUCO Nominating Council Seeks Applicants for Commissioner Position

May 20, 2016

The Public Utilities Commission of Ohio (PUCO) Nominating Council is seeking applicants for the position of commissioner of the PUCO to fill the vacancy created by Andre Porter's resignation.

The PUCO Nominating Council is a broad-based 12-member panel that screens candidates for the position of PUCO commissioner. The PUCO is comprised of five commissioners appointed to rotating, five-year terms by the governor. The commissioners are responsible for regulating Ohio's investor-owned public utilities.

After reviewing the résumés of all applicants, the Nominating Council will interview and narrow the list to those most qualified for the position, and recommend four finalists to Gov. Kasich. The governor will have 30 days to either appoint a commissioner from the list or request a new list from the Nominating Council. The governor's appointment is subject to confirmation by the Ohio Senate.

OMA Energy Committee Heads to Akron

May 20, 2016

In response to member interest in more regional opportunities, the OMA Energy Committee will meet in Akron on Wednesday, May 26 from 10:00 a.m. until 1:00 p.m., and includes lunch.

The meeting will be held at Ariel Corp., 3194 Massillon Rd., Akron, OH 44312. An optional 45-minute tour of the Ariel Corp. facility follows the meeting. Ariel has a sophisticated metal machining operation at this location.

In addition, members are invited to a networking dinner the evening prior, Wednesday, May 25, at Bender's Tavern, 137 Court Ave SW, Canton, OH 44702.

Please register here for in-person or call-in attendance, and dinner option. Or call us at (800) 662-4463.

PUCO Moves Fast to Grant FirstEnergy Bailout Rehearing

May 13, 2016

The Public Utilities Commission of Ohio (PUCO) granted FirstEnergy's request for a rehearing of its subsidy request (derailed by a ruling of the Federal Energy Regulatory Commission (FERC)). The PUCO acted before its deadline for parties to file opposition to a rehearing.

The new FirstEnergy proposal would require ratepayers to pay a rider directly to the distribution utility, rather than to the generation affiliate, in an attempt to sidestep FERC oversight. The rider, if approved, is estimated to cost customers $4 billion over eight years.

FirstEnergy had argued that the previous plan was necessary to keep two plants operating to assure adequate electricity supply. Under the new plan, the two plants receive no revenue.

The OMA Energy Group will oppose the new plan of FirstEnergy before the PUCO, and, if necessary, at FERC.

New Study: Wholesale Markets Working Well

May 13, 2016

A new study commissioned by PJM, the regional transmission organization serving Ohio, finds that wholesale markets are providing the benefits they were designed for: lower costs, greater efficiencies, innovation, and attraction of cost-effective generation.

The report debunks the claim that wholesale markets are forcing premature retirements of legacy generation units. It finds that retirement rates are similar in market and regulated areas.

The report warns state policymakers from distorting the effectiveness of the markets with subsidies to interests claiming that the markets aren't working.

"The simple fact that a generating facility cannot earn sufficient market revenue to cover its going-forward costs does not reasonably lead to the conclusion that wholesale markets are flawed. More likely, it demonstrates that the generating facility is uneconomic," states the report.

House Bill Freezes Energy Standards Forever

May 13, 2016

Speaker Pro Tem Ron Amstutz (R-Wooster) proposes to eliminate Ohio's energy efficiency and renewable energy standards in his recently introduced House Bill 554.

Legislation last session froze the standards until January 1, 2017, in order to give the legislature time to study the standards. If the legislature does not act prior to that date, the standards will go back into effect.

Meanwhile, hearings continue in the Senate on Senate Bill 320, introduced by Senator Bill Seitz (R-Green Township), which would extend the freeze for three years and make multiple changes to Ohio energy law.

Kasich Picks Haque for PUCO Chair

May 13, 2016

This week Governor Kasich named Asim Z. Haque, a member of the Public Utilities Commission of Ohio (PUCO) since 2013 and the current vice chair, to serve as chairman of the commission. Haque will succeed Andre Porter, who recently announced that he would step down as chairman on May 20 to accept a position in the private sector.

Haque was first appointed to the PUCO by Gov. Kasich in June 2013 to complete three years of an unexpired term and recently reappointed by the governor to a full five-year term. His term will expire in April 2021 and the appointment is subject to the consent of the Ohio Senate.

Haque holds a bachelor of arts degree in chemistry and political science from Case Western Reserve University and a juris doctorate from The Ohio State University Moritz College of Law.

FirstEnergy Doubles Down on Subsidy Demand

May 6, 2016

One week after its proposed "power purchase agreements" (PPAs) were halted by the Federal Energy Regulatory Commission (FERC), FirstEnergy filed a new subsidy proposal to the Public Utilities Commission of Ohio (PUCO). The company wants the PUCO to approve it by May 25 so that it can go into effect on June 1.

Essentially walking away from any pretense that its proposal is anything more than a costly bailout, the filing drops the PPAs and any connection to the wholesale markets. Instead, the subsidies are based on the company's own past projections of future costs, not actual costs set by the market.

Once again, customers potentially have more than $3 billion over eight years at risk.

Read a good summary of the proposal in the Cleveland Plain Dealer. We'll have a full analysis for members in a few days.

AEP Accepts FERC Decision

May 6, 2016

AEP this week accepted the Federal Energy Regulatory Commission (FERC) decision that rescinded a waiver that would have allowed its Public Utilities Commission of Ohio (PUCO) approved "power purchase agreement" (PPA) between its distribution utility and its affiated power plants.

The company now is asking the PUCO to approve a PPA only for the power it controls as part of the Ohio Valley Electric Corp. (OVEC) in southern Ohio. OVEC generates 440 megawatts, or less than 15% of the total previously requested by AEP. OVEC is the only plant owned by the AEP distribution facility (rather than its retail generation affiliate).

AEP has indicated it will continue to push for customer-financed wind and solar projects totalling 900 megawatts, and that it will seek legislative "re-regulation" of generation.

Energizing Manufacturing

May 6, 2016

The National Association of Manufacturers (NAM) released a comprehensive study of the benefits of natural gas and natural gas infrastructure this week.

The study finds: "Total natural gas demand is poised to increase by 40% over the next decade. Key drivers will be manufacturing and power generation. U.S. supply is expected to increase by 48% over the next decade to meet new demand."

Among the economic benefits:

- Natural gas access contributed to 1.9 million jobs economy-wide in 2015.
- Shale gas put an extra $1,337 back in the pocket of the average American family.
- New natural gas pipelines created more than 347,000 jobs, with 60,000 in manufacturing.

The study calls for more infrastructure development to allow American manufacturers to take full advantage of the U.S. natural gas resources.

Read the report, and its summary, here.

Don't Be in the Dark about LED Lighting, webinar

May 6, 2016

The OMA Energy Efficiency Peer Network (EEPN) has scheduled a one-hour webinar on Wednesday, May 25 at 10:00 a.m. – **Technology Check-in: LED Lighting in Manufacturing Facilities.**

LED lighting technology and costs change rapidly. This presentation will update you about current LED technology and how it is being applied in manufacturing environments, including:

- Exterior, High Bay and Low Bay applications
- Are the T8 linear fluorescent to LED tube retrofits a good idea? Cost effective?
- Tips to ensure quality in LED projects
- Are all LED fixtures always the most efficient options?
- Should you consider replacing fluorescent lights with LED lights, or just HID?
- How to optimize LEDs with occupancy, dimming and photo-sensor controls
- What are the approximate economics of different LED applications or situations?

The webinar will also feature case studies presented by peer manufacturing facilities.

All interested members welcome! Register at My OMA or call us at (800) 662-4463.

Manufacturers Receive AEP Ohio Energy Efficiency Award

May 6, 2016

Last week AEP Ohio honored organizations that have demonstrated a strong commitment to energy efficiency.

Crown Battery Manufacturing Company, Fremont, received a Sustained Excellence Award for its energy efficiency efforts over multiple years as well as for making energy efficiency a part of company culture. (You may recall the OMA Energy Efficiency Peer Network held a plant tour at Crown Battery last year.)

Additional recognized manufacturers were Bridgestone, Upper Sandusky, and LuK, Inc., Wooster.

AEP Ohio offers a variety of energy efficiency programs and discounts to help business customers conserve energy and save money. Through the programs, AEP Ohio customers save an estimated $2.2 billion over the life of the measures. For more information visit AEP Ohio or contact OMA's energy engineer, John Seryak.

FERC Halts PUCO's Approval of AEP & FirstEnergy Non-bypassable Riders

April 29, 2016

This week the Federal Energy Regulatory Committee (FERC) issued a decision that halts the underlying transactions of the Public Utilities Commission of Ohio (PUCO)-approved subsidy requests from Ohio-based utilities AEP and FirstEnergy. Their bailout proposals would have forced Ohio customers to subsidize old, inefficient power plants for the next eight years at an estimated cost of $6 billion.

OMA president Eric Burkland issued a statement commenting on the FERC's decision, saying: "The OMA strongly opposed the PUCO decision that harmed wholesale markets that are benefitting Ohio electricity consumers and that served to subsidize potentially uneconomic utility generating units. ... The unanimous FERC decision is welcomed by Ohio manufacturers that depend on markets to provide the cost and innovation benefits of competition."

The non-bypassable new costs under the PUCO-approved plans would have come at a time when the competitive electricity marketplace has begun to mature and is producing benefits in cost savings and innovative, new products. The utilities' plans would add costs to customers' bills with no commensurate benefits.

In an effort to prevent the potential damage, the OMA Energy Group, among others, pursued its available legal appeals to the FERC.

This one-page summary of the FERC decision prepared by OMA energy counsel, Carpenter Lipps & Leland notes: "FERC agreed with the arguments asserted by OMAEG (OMA Energy Group) ... that customers are captive because they have no ability to avoid the costs associated with the Affiliate PPAs by shopping with a competitive supplier."

To learn more about how through the OMA Energy Group you can effect change that protects your company, please contact OMA's Ryan Augsburger.

Energy Standards Freeze Introduced

April 29, 2016

Senator Bill Seitz (R-Green) introduced a bill, Senate Bill 320, that extends the freeze on the state's renewable and energy efficiency standards for another three years. The bill makes extensive other changes to the state's energy statutes.

Read this analysis prepared for the OMA by Runnerstone.

Ohio Supreme Court Finds PUCO Erred

April 29, 2016

Late last week, the Ohio Supreme Court decided two separate cases impacting AEP customer charges.

In the first case, Justice Sharon Kennedy authored the high court's decision finding that the PUCO incorrectly authorized AEP to recover from customers the equivalent of transition revenues through the retail stability rider. This is a significant win for customers, estimated to result in a $310 million reduction to customers.

In another case also authored by Justice Kennedy dealing with AEP's capacity-pricing mechanism, the court found in favor of AEP, stating that the PUCO erred by failing to adequately explain the method it used to calculate credits used to reduce the capacity charge. The court did not find that the capacity charge collected was incorrect, just that the PUCO had not adequately explained its decision.

Both cases were sent back to the PUCO.

PUCO Chairman to Exit?

April 29, 2016

This Columbus Dispatch report indicates that that PUCO Chairman Andre Porter will depart the agency soon for a position out-of-state. He has not been chair very long.

SCOTUS Protects Wholesale Electricity Markets

April 22, 2016

In a decision with major implications for the recently approved, customer-punishing power purchase agreement (PPA) cases of AEP and FirstEnergy, the U.S. Supreme Court ruled unanimously that a

Maryland Public Service Commission (Maryland PSC) plan to boost in-state generating capacity with subsidies paid by ratepayers unlawfully intruded on the Federal Energy Regulatory Commission's (FERC) jurisdiction over wholesale rates.

The court affirmed that FERC has the exclusive authority to set wholesale energy and capacity prices and oversee whether those rates and charges are just and reasonable.

An OMA Energy Group analysis of the decision notes: "The Court's decision bolsters OMA Energy Group's position in the AEP and FirstEnergy PPA cases before FERC. Just like in the Maryland case, the PPAs in the AEP and FirstEnergy cases guarantee a rate that is distinct from the clearing price set in PJM's capacity auction. The PPAs at issue in the AEP and FirstEnergy cases guarantee a payment to the generators different from the clearing price set in the PJM auction."

OMA Energy Group has argued that this type of arrangement, just like in Maryland, impermissibly interferes with FERC's authority to oversee wholesale rates as the guaranteed revenue stream from customers will make the affiliate generating units agnostic to wholesale-market prices, distort wholesale-market price signals, and deter new entry from competitive generation suppliers.

Read more in this energy blog by OMA counsel Bricker & Eckler.

Tracking U.S. Energy Efficiency Performance

April 22, 2016

The American Council for an Energy-Efficient Economy (ACEEE) has posted a new web page of national indicators of energy efficiency in the U.S. The web page shows energy efficiency trends by sector.

According to ACEEE metrics, nationally, energy productivity is trending upward over a five-year period. Productivity is the amount of service or useful work produced by a unit of energy.

Similarly, the energy intensity of the U.S. industrial sector (manufacturing, agriculture, mining, and construction) has been improving steadily. Nationally, less energy is needed per dollar of goods produced.

See the data here.

Costly PPA Provisions Summarized

April 15, 2016

OMA energy counsel, Carpenter, Lipps & Leland, has summarized the provisions of the power purchase agreement (PPA) cases of both AEP and FirstEnergy.

OMA general counsel, Bricker & Eckler, has drafted a summary of the renewable and advanced energy provisions of both cases here. Bricker also put together a one-pager on what's next on the matters, which you can read here.

The OMA Energy Group has filed a complaint with the Federal Energy Regulatory Commission (FERC), asking FERC to void the decisions as illegal, customer-punishing incursions into the operation of wholesale electricity markets. The Energy Group is also evaluating legal options to stop implementation.

OMA Energy Committee Heads to Akron

April 15, 2016

In response to member interest in more regional opportunities, the OMA Energy Committee will meet in Akron on Wednesday, May 26 from 10:00 a.m. until 1:00 p.m., and includes lunch.

The meeting will be held at Ariel Corp., 3194 Massillon Rd., Akron, OH 44312

As usual, a call-in option will be available at: (866) 362-9768, 940-609-8246#

In addition, members are invited to a networking dinner the evening prior, Wednesday, May 25, at Bender's Tavern, 137 Court Ave SW, Canton, OH 44702.

Please register here for in-person or call-in attendance, and dinner option. Or call us at (800) 662-4463.

Senate Republicans Prepare to Extend Energy Standards Freeze

April 15, 2016

Senator Bill Seitz (R – Cincinnati) shared with interested parties draft legislation to revise Ohio's renewable and energy efficiency standards. Senate Bill 310 from the prior session, instituted a freeze of escalating standards. That freeze is slated to go back into effect in early 2017.

The Senate bill draft would extend the freeze for both renewable energy and energy efficiency for an additional three years. The bill also reduces annual benchmarks in out years and expands the ability of business customers to opt-out of the riders.

Columbus Dispatch reporter Dan Gearino posted an article describing some early reactions to the proposal.

Webinar: Case Studies in Ohio CHP Success

April 8, 2016

Since 2012, enabled by Senate Bill 315, electricity customers have been able to seek an energy efficiency rebate for Combined Heat and Power (CHP) and Waste Energy Recovery (WER) systems from their electric utility.

This 90-minute webinar on Tuesday, April 12 at 10:30 a.m. EDT will feature presentations from Jon Williams, AEP-Ohio, Manager, Energy Efficiency & Demand Response, and two AEP-Ohio industrial customers, Kraton Polymers and Solvay Specialty Polymers, that have developed qualifying CHP projects. Presenters will discuss project financing, efficiency and savings benefits, as well as challenges and lessons learned.

This webinar is designed for CHP and WER developers and electric customers, clean energy policy advocates, technical experts, policymakers and regulators and their staff. This webinar is free and open to the public, but advance registration is required.

PUCO Approves Controversial Utility Affiliate Power Purchase Agreements (PPAs)

April 1, 2016

This week, the five-member Public Utilities Commission of Ohio (PUCO) convened a special Thursday meeting to approve two proposals, advanced by AEP and FirstEnergy, to implement new non-bypassable riders and other cost-driving provisions.

With the approval of these deals, AEP and FirstEnergy will be able to collect costs from all their customers to subsidize uneconomical generation assets, thus placing all operating risk onto their customers, while guaranteeing their profits. Their customers will be saddled with the riders for a term of eight years.

OMA estimates cost impacts to manufacturers will range from tens of thousands of dollars to tens of millions of dollars, depending on the amount of electricity consumed.

Because the deregulated electricity market in Ohio has been working to lower costs and spur innovative, new products, the OMA Energy Group has opposed the PPA proposals in the PUCO proceedings. Many industry leaders have independently expressed concerns to the PUCO.

The OMA Energy Group has filed a compaint before the Federal Energy Regulatory Commission (FERC) to prevent the ruling from going into effect.

OMA Reacts to PUCO PPA Decision

April 1, 2016

Eric Burkland, president of The Ohio Manufacturers' Association (OMA), issued a statement yesterday commenting on the Public Utility Commission of Ohio's (PUCO) decision to approve Power Purchase Agreement (PPA) plans for FirstEnergy and American Electric Power (AEP).

Burkland said, "Today's decision by the PUCO to approve requests from FirstEnergy and AEP to impose billions of dollars in new customer costs to fund the utilities' power purchase agreements with their deregulated affiliates is a setback for electricity consumers in Ohio. If implemented, the agreements will serve essentially as new taxes on families and businesses, which will become a drag on the state's economy."

Read the full statement.

OMA Asks PUCO for a Stay in PPA Cases

March 25, 2016

The OMA Energy Group joined the Ohio Consumers Counsel this week to file a motion with the Public Utilities Commission of Ohio (PUCO) to stay a decision in litigation initiated by electric utility companies, AEP and FirstEnergy. If approved, the stay would delay the PUCO's ability to issue a decision in the controversial utility affiliate power purchase agreement (PPA) cases until the Federal Energy Regulatory Commission (FERC) has a chance to rule on a related case.

The outcome of the pending FERC case is expected to determine the legality of Ohio regulators being able to approve a utility affiliate PPA.

Belden: PPAs are Regulatory Taxation

March 25, 2016

The Canton Repository published an op-ed this week from OMA Energy Group Chairman Brad Belden, Director, Support Services, The Belden Brick Company, the largest family-owned and operated brick company in America. He warned of "regulatory taxation" by the Public Utilities Commission of Ohio.

Belden wrote of the riders proposed in the AEP and FirstEnergy "purchase power agreement" (PPA) cases: "We estimate that Belden Brick's share of the additional costs of this new rider to approach $1 million over the eight-year term of the agreement. The construction industry is still feeling the effects of the real estate collapse of several years ago, and our company is still struggling to turn a profit. Belden Brick did not have the government to turn to during this recent downturn. AEP and FirstEnergy should not have this option either ..."

He said: "The markets for electricity in Ohio have been working to the benefit of consumers, but these proposed deals are a massive setback to the consumer-friendly efficiency of those markets. The impact would surely be felt by our employees and shareholders. Since Ohio deregulated its utilities, we have been able to shop for the best price on electricity generation, and that has helped keep costs down. ... Lower energy prices mean more money to invest back into the business, into employee salaries and our community. That's how the American free market works."

DP&L Proposes New Rate Plan to PUCO

March 4, 2016

Dayton Power & Light (DP&L) filed its electric security plan this week. The proposal seeks, among other things, a ten-year power purchase agreement (PPA) with its generating affiliate, to be funded by a Reliable Electricity Rider. The proposal also includes a Distribution Investment Rider and a Clean Energy Rider.

DP&L maintains that the Reliable Electricity Rider is needed "to promote the reliability of electric supply and the stability and growth of Ohio's economy" and is consistent with the criteria used by the Public Utilities Commission of Ohio to evaluate AEP's PPA rider proposal.

The OMA Energy Group will be intervening in the case to protect manufacturing competitiveness.

OMA Files at FERC to Stop Market-Damaging Subsidies

February 26, 2016

This week, the OMA Energy Group filed in a complaint before the Federal Energy Regulatory Commission (FERC) to protect manufacturers and other consumers from abuses in the FirstEnergy and AEP affiliate power purchase agreement cases pending before the Public Utilities Commission of Ohio (PUCO).

The OMA Energy Group wrote that the FirstEnergy proposal will cost consumers $3 billion, the AEP proposal will cost $2 billion, and both will undermine Ohio manufacturing competititveness and chill investments in the Ohio markets.

The Energy Group stated that the proposal will harm competition in regional wholesale markets, distort wholesale price signals, and deter market entry by competitive electricity suppliers.

The group also noted that evidence in the case clearly shows that retail electricity competition is working, retail rates are not subject to volatility, and that resource adequacy exists in the PJM region.

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- Power resources are moving behind the meter
- Customer-sited resources effect the price of electricity, can reduce costs for manufacturers, and may provide revenue. They are:

Energy Efficiency

Combined Heat & Power / Waste Energy Recovery

Demand Response

Distributed Renewables & Storage

Questions?
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CUSTOMER-SITED RESOURCES

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CUSTOMER-SITED RESOURCES REPORT

ENERGY EFFICIENCY - DEMAND RESPONSE - CHP - RENEWABLE ENERGY - STORAGE

ENERGY COMMITTEE – MAY 2016

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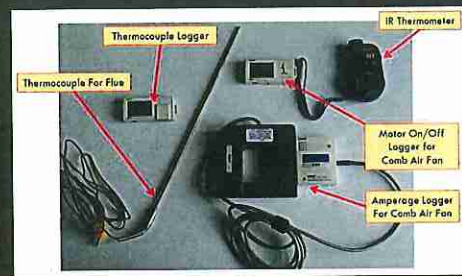
Energy Efficiency Peer Network

- ❑ Technical assistance
    - ❑ Ex. Questions on installing new meter
    - ❑ Ex. Installing VFD on fan with inlet guide vanes
- ❑ DIY tools, logging kits
- ❑ Join - http://www.ohiomfg.com/omas-chpweree-work-group/



	Boiler 1	Boiler 4	Boiler 5
Heat provided (mmBtu/year)	20,770	22,693	36,026
Boiler efficiency (%)	80.50%	78.00%	82.00%
% Time Active	57.9%	99.3%	99.6%
Annual Gas Use (mmBtu/year)	25,801	29,094	43,934
Avg % Fire	40%	39%	52%

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ENERGY EFFICIENCY

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Energy Efficiency Peer Network

- ❑ Tour @ Dannon
    - ❑ Wednesday, July 20th – Minster, Oh
- ❑ 2016 calendar
    - ❑ 3/18 - Tour @ F&P America
    - ❑ 5/25 – Webinar – LED lights
    - ❑ 7/20 – Tour @ Dannon
    - ❑ 9/16 – Webinar – Corporate energy goals: Measuring progress
    - ❑ November - Tour @ Anheuser Busch
- ❑ Join - http://www.ohiomfg.com/omas-chpweree-work-group/

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ENERGY EFFICIENCY

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ADVANCED ENERGY & THE PPAS

ENERGY COMMITTEE – MAY 2016

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- ❑ Advanced energy in the Power Purchase Agreements (PPAs)
- ❑ Utility energy efficiency programs
- ❑ Renewable Portfolio Standard (RPS), Energy-Efficiency Resource Standard (EERS)
  - ❑ Recently introduced legislation

Questions?
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CUSTOMER-SITED RESOURCES REPORT

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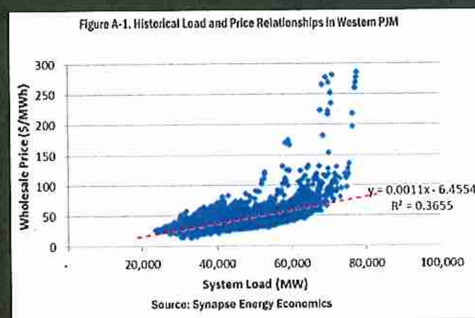
- **<u>Rate design</u>** - Are we moving away from price signals?
  - Generation – Non-bypassable PPA rider
  - Transmission pricing – Move from market based 1 Coincident Peak (CP) pricing
    - Rider NMB (FE), Rider BCTR (AEP) price on 12 monthly distribution peaks
  - Distribution
    - Straight-fixed-variable residential rate design; 75% of distribution costs would be fixed.
    - Diminishes price signal
- Themes
  - Rate-basing and regulating potentially competitive new resources
  - Diminishing price signal, and thus ability to realize cost savings from energy management



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POWER PURCHASE AGREEMENTS – THEMES

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- **<u>Renewable energy</u>**
  - FE – 100 MW of wind or solar with its own power-purchase agreement rider. Non-bypassable.
  - AEP – 500 MW of wind, 400 MW of solar (900 MW total) within the power-purchase agreement. Non-bypassable.
    - AEP affiliate may own up to 50%
  - PUCO – Asking for bilateral agreements first
- **<u>Energy efficiency</u>**
  - FE – 800,000 MWh/year, subject to opt-outs
    - $25 million /year profit, "after tax" = ~$35-$40 million
- **<u>Battery storage</u>**
  - Unspecified amount of storage; would be owned by distribution utility with full rate recovery.
  - Competitive issues - Pre-regulates new assets; batteries are currently competitive resources

Questions?
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POWER PURCHASE AGREEMENTS – ADVANCED ENERGY: STILL ON?

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- **Utility efficiency programs** – All four investor-owned utilities (AEP, DP&L, Duke, FE) will submit plans for 2017-2019
  - Generally, utilities seek input from customer groups
  - We're seeking input – what is working / not working

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ENERGY EFFICIENCY - UTILITIES

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UTILITY ENERGY EFFICIENCY PROGRAMS

ENERGY COMMITTEE – MAY 2016

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- **<u>Beware "Customer Action" Program (CAP)</u>**
  - FE only, so far
  - FE purports that SB 310 forces them to do this
  - FE "captures" customer efficiency to count toward it's energy-efficiency benchmarks. Compare:
    - CAP
      - FE will collect profit on customer actions
      - FE has not indicated if there are incentive levels
    - Self-direct
      - Customer has choice of rider exemption or incentive
      - FE does NOT collect profit on customer actions

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ENERGY EFFICIENCY - UTILITIES

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- **<u>2017 Opt-Out</u>** – All above-primary and tax self-assessing manufacturers can opt-out of participation in energy-efficiency programs. We're seeking input:
  - If you're opting out – What could you still use? Ex. – PJM payments, tracking energy use, information, etc.
  - If you'd like to stay in – What would you need to stay in?

- **<u>Self-Direct</u>** – Each utility's rider will be somewhat different

- Pick your path – Opt-out? Self-direct? Program Participation

Questions?
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ENERGY EFFICIENCY - UTILITIES

Resource Investment in Competitive Markets

May 5, 2016

PJM Interconnection

pjm

A Note on the Organization of this Paper

This study is presented in two parts.

Part 1 (page 6) examines how markets drive resource investment decisions and compares generation entry and exit outcomes under both market and traditionally regulated constructs. The findings show markets do produce efficiencies when left to manage resource entry and exit.

Part 2 (page 35) explores subsidies, regulations, policies and other requirements that may either reward or disadvantage generating resources and how such actions affect the performance of markets. This discussion concludes that the value proposition revealed in Part 1 can be devalued or lost altogether unless coherent public policies are pursued.

Executive Summary

Organized wholesale electricity markets were created to address burgeoning costs of new power generation under the traditional regulatory scheme and to encourage innovation through free-enterprise competition. The discipline of the marketplace promised lower costs and greater efficiencies. Two decades of experience and numerous studies have demonstrated competitive wholesale markets in PJM and elsewhere bring increased operational efficiency and innovation, resulting from transparent market prices and the benefits of single, independent dispatch across a broad region. These benefits are realized through economies of scale that permit optimization of a large and diverse set of resources and load. The resulting efficiencies are measured in reduced heat rates and increased capacity factors.

However, as a host of organic and external factors change the power supply landscape, some have questioned the efficacy of competitive wholesale markets at promoting the most efficient entry and exit of resources – especially compared to traditional utility regulation with administrative planning and direction, such as under a state-integrated resource plan. Various forces, including federal and state public policies, low-priced domestic natural gas and static or declining levels of wholesale electricity consumption, have challenged incumbent or "legacy" generation resources by increasing operating costs, creating capital investment needs and reducing revenues realized in PJM's energy, capacity and ancillary service markets. For the least efficient of these resources – older, small coal units, single-unit nuclear stations and older, high-heat-rate natural gas and oil-fired generation – these cost and revenue pressures have threatened their ongoing viability and not unexpectedly have led to retirements in many cases.

Consequently, some observers have questioned whether wholesale markets have forced premature retirements of viable legacy generating resources and whether markets can be relied upon to ensure adequate power supplies in light of the retirements. The questions raised with regard to decisions and outcomes related to the changing nature of the supply portfolio in PJM can be summarized as:

> *Can we rely on PJM's organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation?*

The goal of this paper is to answer this question. In doing so, this paper does not present itself as an exhaustive or scientific analysis of what are complex issues characterized by numerous variables. In some cases, the value proposition brought to the generation investment decision by competitive markets can be shown with a high degree of confidence. In other cases, the relative advantage of a competitive versus a regulated paradigm in efficiently bringing in new generation and exiting inefficient generation is more arguable. Finally, certain challenges and difficult outcomes necessarily result from the operation of PJM markets in driving investment decisions – challenges and difficulties involving choices between often-competing social and political interests. In contrast, when investment decisions are driven by utilities and their regulators, a trade-off between diverging policy interests can be made directly and explicitly, though not necessarily from a well-informed understanding of the trade-off.

Collectively, the analyses show that the PJM markets are efficiently and reliably managing entry and exit, even while adapting to changing circumstances.

Entry of New Resources

The markets do well in attracting new entry at an efficient cost. Competition lowers costs and excludes technologies with inappropriately high costs. Markets transparently evaluate the economics of proposed projects, and projects that are uneconomical are not built. Importantly, in the market paradigm risk is shouldered and managed by the supplier, not the customer. A financial analysis based on tools of modern portfolio theory was undertaken to try to quantify (in broad terms) the value customers receive in avoiding such risk. This analysis indicates that allowed returns on equity in regulated generation are notably higher than the models would predict given the lower risks relative to merchant investors.

Strong evidence supports the belief that markets are providing adequate returns to incent new generation investment where warranted. For the years 2010-2015 approximately 134,000 MW of proposed natural gas generation entered the PJM generation queue. There now are approximately 74,000 MW in active development, 19,500 MW in service, 3,500 MW in partial service and 35,000 MW under construction. Beyond natural gas generation, the markets are also driving investment in innovative technologies with lower capital costs, providing benefits to consumers.

Innovation

PJM markets provide an accommodating, transparent environment that allows any project or technology to demonstrate its value to the customer based on the combination of capital costs, risks and value, which collectively determine whether a project will flourish or fail fairly based on its merit. Markets do well in pricing operational attributes and innovations of new technologies – generation, storage or demand side – that provide the desired attributes more effectively and economically. Many investment risks can be efficiently managed through financing structures and through hedging tools available in PJM markets and through instruments that have evolved in the greater "ecosystem" of supporting bilateral and exchange-traded commodity markets.

Exit of Resources

No evidence suggests the PJM markets inadequately compensate legacy units and thus are forcing a premature retirement of economically viable generators. PJM's markets are producing prices that are efficiently and reliably signaling the exit of uneconomic legacy resources and the entry of efficient, new resources. A statistical examination of retirement data in PJM compared to regulated environments refutes any assertion that PJM markets are prematurely retiring economically viable generation. When faced with similar capital investment requirements, generator retirements are roughly comparable in market and regulated environments.

In PJM, the decision to shutter a generating station, perhaps before the end of its operationally useful life or the term of its operating permit, is based on market forces – more precisely the owner's assessment of whether the market will provide revenues sufficient to meet the facility's going-forward operating costs. PJM's markets produce transparent prices that provide clear benchmarks for evaluating the continuing economic viability of generation, even for utilities and regulators in those PJM states that have retained a traditional, rate-base regime.

Markets and Public Policy

Realizing the "investment efficiency" advantages of PJM markets can require policymakers to accept tough choices and trade-offs because efficient market outcomes may inflict harm to other policy objectives. Policymakers must weigh these trade-offs but should understand that pursuing individual actions that defeat efficient market outcomes can thwart effective operation of the market. One likely result is that the market no longer can be relied upon to efficiently and effectively provide price signals to achieve efficient and reliable resource entry and exit. This paper acknowledges the widespread existence of subsidies of all sorts that influence PJM market outcomes.

PJM's mission is to provide for a reliable and efficient wholesale power supply. The markets it designs and administers to accomplish this mission do not necessarily promote and may even conflict with other valid public policy interests that state and federal lawmakers and regulators may pursue to meet environmental, social and political interests distinct from the markets' singular mission to deliver the most cost-efficient resources needed to serve customers reliably.

Although PJM markets are efficiently and reliably handling a changing resource mix resulting from forces currently affecting the industry, PJM's continuing ability to deploy market forces to handle this responsibility is threatened if actions taken by lawmakers and regulators to promote other policy interests are pursued in a way that materially distorts price outcomes in PJM's capacity and energy markets.

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Introduction

Before electric industry restructuring and the introduction of wholesale competition, the electricity industry operated exclusively under rate-of-return or cost-of-service regulation with each vertically integrated utility operating effectively stand-alone, albeit interconnected, systems. This paradigm ushered electrification into our daily lives and did so with declining retail rates and declining average costs in real-dollar terms until the early 1970s.[1]

However, from the early 1970s to the advent of electricity industry restructuring with the Energy Policy Act of 1992, the industry witnessed overbuilding of generation facilities to serve load, poor performance of the nuclear generation fleet and expensive long-term contracts under the Public Utility Regulatory Policy Act of 1978. All of the above led to rising electricity rates in real terms after nearly 60 years of declining rates and average costs, with the risks of these decisions borne almost entirely by the ratepayers.[2]

Wholesale competition, spurred by FERC Orders 888 and 889 in 1996 within the context of independent system operators (ISOs), and later regional transmission organizations (RTOs), was designed to bring greater efficiencies in operations, reducing generation operating costs and improving generator performance. Moreover, such a regime has the effect of shifting the risk of poor performance and decisions from the ratepayers back to the owners of generation.

However, since early in this period of restructuring, debates have continued over the relative merits of the competitive market model versus the traditionally regulated model. This debate intensified during the California power crisis in 2000-2001. The debate continues as power prices swing from one extreme to another due first to growing and now to falling demand and natural gas prices.

In the course of this debate, academic economists, through sophisticated modeling and statistical techniques, found that the move to wholesale competition under the ISO/RTO model brought efficiency gains in overall system operations and reduced costs – or found greater efficiencies for the existing generation fleet through improved operating costs, fuel-use efficiency and availability and performance. These findings, published in numerous academic papers and studies, demonstrate what this paper refers to as the "operational" benefits realized by competitive markets.

While these findings are recapped in summary form below, none of the aforementioned economic studies examines closely the role of market forces in bringing about new entry or the retirement/exit of resources. So, while compelling evidence reveals that the ISO/RTO structure more efficiently manages an existing portfolio of resources, the less scrutinized question asked here is whether that model is more effective in determining what goes into that portfolio. Do competitive wholesale power markets lead to more efficient and cost-effective capital investment decisions for new entry, retirement and investment in existing resources to remain in commercial operation? The focus here is to examine the "investment" benefits of competitive electricity markets.

[1] See United States Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011), September 2012, Figure 8.10, p. 254 http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

[2] *Id.* Nominal retail rates were, on average, more than three times higher in 1992 than in 1970, and real electricity prices remained approximately 25 percent higher than they were in 1970. Literature is replete with examples through the 1970s and 1980s of states struggling to manage out-of-market PURPA contracts and nuclear plant cost overruns by orders of magnitude from initially approved budgets. Examples of these regulatory misadventures during that time period are frequent and well documented. They are raised here to remind the reader of the challenges that face regulators in picking winners and losers and why instilling competitive forces into the industry took hold.

Gains Realized by Wholesale Markets – "Operational Efficiencies"

The development of ISOs and RTOs brought scale and geographic scope economies to wholesale power transactions and operations. The scale economies come from implementing security constrained unit commitment and economic dispatch across wider regions allowing lower overall costs of system operation by eliminating seams, reducing transaction costs and permitting a free flow of lower-cost energy across the wider region. Additionally ISO/RTOs bring economies of scale to resource adequacy and transmission planning across a much wider region rather than looking at smaller systems in isolation.

A Government Accountability Office study in 2008 compared the costs of operating ISO/RTOs across the United States and recommended that there be some attempt at measuring the benefits for these costs.[3] The Midcontinent Independent System Operator estimates a cumulative benefit to customers in that area from 2007 through 2015 to be $12.2-$16.8 billion.[4] PJM estimates the total annual benefits overall to customers in its footprint of to be in the range of $2.8-$3.1 billion.[5] In PJM this value translates to just under $4/megawatt-hour contrasted against a PJM administrative cost of $0.32/MWh or a more than tenfold return on the investment PJM members make each year.[6]

Efficiency gains with regard to dispatch have been shown prominently in the academic literature by Mansur and White (2012)[7], Wolak (2011)[8] and Joskow (2006).[9]

Figure 1 below reproduced from Mansur and White clearly shows that the impact of expanding the scope of RTO operations, in the case the integration of AEP and Dayton Power and Light, increases flows of energy from west to east as lower-cost energy from the Midwest is now more easily available to serve load in the eastern part of the PJM footprint. The resulting efficiencies produced benefits for all consumers.

[3] By way of example, in 2008, the GAO summarized competing expert reports analyzing the benefits of electricity restructuring as an appendix to: *FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance* (GAO-08- 987, Sept. 2008), at 78. Online at: http://www.gao.gov/new.items/d08987.pdf

[4] Midcontinent Independent System Operator, *Value Proposition.* Online at https://www.misoenergy.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx.

[5] PJM Interconnection, LLC. *PJM Value Proposition* estimates the value is $2.8-$3.1 billion per year. Online at http://www.pjm.com/about-pjm/value-proposition.aspx.

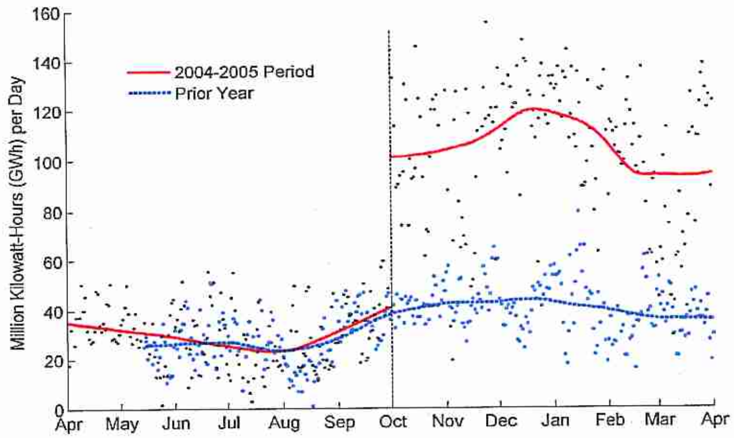
[6] For the total energy in PJM in 2014 of 795,519,000 MWh this comes out to $3.52-$3.90/MWh. See *PJM Load Forecast Report, January 2016*, Table F-2, p. 94. Online at http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx. PJM also publishes each month and presents to the PJM Members Committee a report summarizing market outcomes with some historic data for context. See Paul M. Sotkiewicz, *Markets Report*, February 22, 2016, p. 6. Online at http://www.pjm.com/~/media/committees-groups/committees/mc/20160222-webinar/20160222-item-07a-markets-report.ashx.

[7] Mansur, Erin T and White, Matthew W., "Market Organization and Efficiency in Electricity Markets". Dartmouth University Working Paper, January 2012. Online at http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf.

[8] Wolak, Frank A. 2011a. "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets", *American Economic Review Papers & Proceedings*, Volume 101, pp. 247-252, 2011.

[9] Joskow Paul L. "Markets for power in the United States: An interim assessment." *The Energy Journal* Volume 27: pp. 1-36, 2006.

Figure 1. Day-Ahead Net Exports from Midwest to East (PJM) before and After the Integration of AEP and Dayton Power and Light[10]



In addition to the operational and planning economies of scale and geographic scope, competitive incentives from wholesale power markets have resulted in more efficient generator operation. Lucas and Wolfram document the improvement in nuclear generator performance due to units operating in a competitive paradigm.[11] They determine that nuclear units subject to competitive pressures have improved availability and shortened their refueling outage times leading to a 10 percent gain in operating efficiency such that these units in aggregate have produced about 4 million MWh more energy, with a market value of $2.5 billion and an implied carbon dioxide emissions reduction of 40 million metric tons. Bushnell and Wolfram document efficiency gains for fossil-fired generating units that equate to a 2 percent reduction in heat rates.[12] Finally, Fabrizio, Rose and Wolfram show that generating units subject to competitive forces and incentives reduced labor costs and other fixed operating costs compared to generating resources that remained under the traditional cost-of-service regulatory treatment.[13]

Evidence supports the assertion that ISO/RTO markets act quickly (*i.e.*, without "regulatory lag") to reflect changed input costs in wholesale energy prices. Average wholesale energy prices in PJM, for example, fell by about 32 percent in 2015

[10] Mansur and White (2012), Figure 2, p. 55

[11] Davis, Lucas W. and Wolfram, Catherine, "Deregulation, Consolidation, And Efficiency: Evidence From U.S. Nuclear Power", *American Economic Journal: Applied Economics*, Vol. 4, pp. 194-225, 2012.

[12] Bushnell, James B. and Wolfram, Catherine. "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants," *CSEM Working Paper Number 140*, March 2005. Online at http://faculty.haas.berkeley.edu/wolfram/Papers/Divest_0331.pdf.

[13] Fabrizio, Kira R., Rose, Nancy L. and Wolfram, Catherine D. 2007. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." American Economic Review, Vol. 97, No. 4, pp. 1250-1277

compared to prices in 2014, driven by declining natural gas prices during that period and the increased incidence of natural gas generation setting the marginal price for energy in PJM.[14]

In short, while the extent of these "operational" benefits might be subject to continuing debate, it is generally accepted that distinct efficiencies are realized through a transparent, independent dispatch and optimization over a broad geographic area to capture advantages of scale and portfolio arising from a diverse weather, load and asset mix. While these studies and findings, including PJM's own assessment of its operational value proposition, show optimization of a given portfolio of energy resources, they say little about whether this portfolio reflects the most efficient, cost-effective set of resources.

A Different Question: Gains Realized by Organized Wholesale Markets – "Investment Efficiencies"

Different ISO/RTOs take different approaches to ensure the most efficient, cost-effective set of resources is established and maintained. In certain ISO/RTOs, decisions as to what resources comprise the resource portfolio are left largely to state regulators, who manage the question of resource exit and entry by traditional cost-of-service regulatory mechanisms, including integrated resource planning or by state-administered resource procurement practices.[15] By contrast in PJM, based to a degree on historical decisions made by various states to introduce retail competition and stimulate merchant competition of supply, market forces (notably the PJM Reliability Pricing Model) signal the efficient exit of legacy resources and entry of new resources.

Competitive wholesale electricity markets should bring about more efficient and competitive resource entry, exit, and retention results for two reasons:

1. There are fewer barriers to entry or exit in the competitive model, in contrast to regulated regimes where entry and exit is managed through a single franchised monopolist.
2. Profitability in a competitive paradigm requires minimizing costs, including investment costs; however, under the traditional cost-of-service structure, profits can be increased by increasing capital spending, and operating expenses generally are passed through to customers on a dollar-for-dollar basis.

Moreover, competitive markets shift the risk inherent in investment decisions from ratepayers to the owners of generation. Competition among merchant investors competing with each other should work to reduce the returns required on invested capital in contrast to administratively fixing an allowed return on rate base through a regulatory proceeding. Finally, an open and competitive market should better attract investment in superior innovations particularly where the operational attributes of such technologies, which are of value to the system operator, are explicitly paid as capacity, energy or ancillary services by market rules. The market also will work to cut off overly risky or costly investments long before they are completed.

[14] Monitoring Analytics, *PJM 2015 State of the Market Report, Volume 2: Detailed Analysis*, March 10, 2016, p. 16, Table 1-8 for the change in energy prices. Figure 3-45 p. 175 shows the reduction in gas prices, and Tables 3-66, 3-67, 3-68 show the Independent Market Monitor-measured change in contribution of gas prices to wholesale energy prices.

[15] In the MISO, Southwest Power Pool and California-ISO markets the value proposition of the ISO/RTO market is essentially confined to what this paper describes as the "operational efficiencies" that come from optimizing a given resource portfolio. ISO New England (ISO-NE) offers an example of an organized market that additionally relies on market tools (ISO-NE's forward capacity market) to establish and maintain an efficient resource portfolio. PJM similarly relies on its capacity market (the Reliability Pricing Model) to meet this same objective. But, because PJM covers a geography that includes several states which have retained regulatory control over the decisions surrounding generation exit and entry, PJM is better regarded as a hybrid of jurisdictions – with some states relying on PJM's market to signal resource exit and entry and others relying less on these forces and more on traditional cost-of-service regulation.

Part 1 of this paper addresses the efficiency and cost-effectiveness of generation investment decisions. This paper is meant to complement and add to existing academic literature and findings – work that has examined the "operational efficiencies" of organized markets, but not empirically addressed the larger investment question. It also responds to economic and policy-driven events that have re-ignited questions about "whether markets work" or if "markets are broken."

The analysis presented in this paper is not meant to settle definitively whether markets are resulting in better and more cost-effective capital investment decisions. Rather, it critically examines the data and other evidence regarding resource investment decisions in the context of what is known about the economic incentives and allocation of risks provided by competitive wholesale power markets and traditional regulatory regimes. The paper compares new combined cycle investment supported by revenues expected from the PJM markets to this same kind of investment supported by full cost-of-service rate regulation. It then examines resource exit, employing statistical modeling tools to compare retirement decisions in PJM with those in a traditionally regulated, non-ISO/RTO environment while controlling for other factors that could influence retirement such as compliance with the Mercury and Air Toxics Standards.

Part 2 then discusses the policies and practices that fall outside the direct purview of competitive wholesale power markets and how these policy choices can affect the ability of wholesale power markets to achieve the most efficient and cost-effective outcomes. While not supporting or opposing particular policy choices, Part 2 explores how various policies integrate with and affect the operation of wholesale power markets in general and specifically in the PJM context.

Part 2 provides the real-world policy context in which the incentives for efficient investment decisions can be reinforced, preserved or undone. Part 2 also provides context for the implied re-allocation of investment risks from generation owners and developers back to ratepayers associated with various policy choices that can impact competitive wholesale power markets.

In summary, the different approaches used to establish and maintain resources for the system operator to optimize raise a question central to Part 1 of this paper: are competitive market mechanisms working well in signaling efficient legacy exit and new entry to arrive at the most cost-effective set of resources to meet system needs reliably? A second-order question is considered in Part 2: assuming competitive market mechanisms efficiently establish and maintain a cost-effective set of resources, do these resources represent the "best" portfolio from a political, social and environmental perspective?

PART 1
Organized Electricity Markets Offer Advantages in Making Resource Investment Decisions

Part 1 begins by summarizing in broad terms the theory and policy objectives governing resource entry and exit under both regulated and merchant investment models. It then moves to actual observations and empirical comparison of new entry in both environments, looking first at unconventional or "cutting edge" technologies, and then focusing on the prevailing cost-effective new entry - natural gas-fired, combined-cycle plants. The entry discussion examines the cost of new combined-cycle plants both notionally and then taking into account the cost and price of risks attendant to the investment. This discussion additionally describes tools PJM's markets offer merchant investors to manage the risks associated with merchant power investment. Part 1 concludes by considering how obsolete or uneconomic legacy investments are exited under both models, empirically examining whether the impact of new federal environmental rules on coal plants is being handled differently under each model.

Theory and Policy behind Investment Decisions in Regulated and Market Environments

Capital allocation and investment decisions for power generation take place under two broad paradigms. Under the regulated cost-of-service paradigm, franchised monopoly utilities make investment decisions through planning processes, such as integrated resource planning programs. These programs are overseen by state public utility commissions where competitive forces are largely absent. Under the market paradigm, diverse market actors independently make generation investment decisions based on market price signals and expected costs and benefits. Between these poles, hybrid examples can be found. Some cost-of-service states instill a measure of competition by requiring incumbent utilities to compare buy-versus-build options and undertake competitive procurement of supply. Still other states operate within organized wholesale markets, yet still rely primarily on traditional utility regulation and integrated resource planning processes, looking to the organized market to provide a competition-based check for their regulatory decisions. Finally, even states that have ceded full responsibility for resource adequacy to organized markets may pursue policies, such as renewable energy certificate requirements that effectively dictate resource investment activities with limited regard for market price signals.

Theories of Entry

An investor-owned utility, governed under "rate-of-return" or "cost-of-service" regulation, earns an administratively determined rate of return on its capital investments less accumulated depreciation. The utility also recovers "prudently incurred" operating expenses.

Regulators determine the allowed rate of return by estimating the utility's cost of capital. In 1962, Harvey Averch and Leland L. Johnson theoretically posited the incentives and behavior of utilities subjected to rate-of-return regulation. They hypothesized that when allowed return on rate base exceeds a regulated utility's cost of capital, the regulated utility has an incentive to deploy more capital than necessary because profits are derived from invested capital. In this case, investing an additional dollar in capital will result in additional profits in the form of return on rate base. Inefficient overinvestment and excessive utility returns result in higher consumer prices.[16]

Regulated utilities also are incented to engage with regulators and legislators in rent-seeking behavior[17] to reduce risk and increase returns. Because there is no competitive market discipline in these monopolies, there is no competitive market behavior to counter a tendency to seek increased returns that translate into higher consumer costs.

In contrast, investors in merchant power projects often have access to more information than a public utility commission, and those investors conduct robust risk analyses before agreeing to support a project. If an independent power project receives the support of sophisticated project lenders and ratings agencies, then market forces and the transparency of the markets have enabled those project lenders to make rational and well-informed decisions about the competitiveness of a project. Public utility commissions do not have the same tools at their disposal and, arguably, are more likely to approve suboptimal projects.

The contrast between the two decision-making regimes becomes most evident in the face of uncertainty. The more uncertainty facing an investment, the more value a market can offer in assessing and managing the risks of these uncertainties. This is true whether the uncertainty is from new forces of change (such as lack of consistent load growth or disruptive technologies) or regulatory uncertainty. Greater information, transparency, and multiple actors should assure that market-based investment decision-making will result in a more comprehensive evaluation and better pricing of risk. Markets thus serve as the crucible from which the most robust solutions emerge. In the face of greater uncertainty, traditional regulated decision-making may cling to potentially old and outmoded paradigms that are no longer effective in the new environment. Importantly, the theoretical advantages offered here assume perfect markets. However, in the real-world, electricity markets do not arise naturally and organically. They are rule-driven, synthetic constructs closely overseen by regulators and policymakers and designed to harness competitive forces to drive efficient outcomes.

Theories of Exit

In competitive markets, decisions by generation owners to exit or go forward depend on whether they expect to cover their going-forward costs.[18] Resources will exit if they operate at a loss or their profits cannot justify needed capital investments. In regulated environments it is less evident whether these same forces apply with the same effect because a utility's economics turn on a return on its rate base.

[16] Averch, Harvey and Johnson, Leland L., *Behavior of the Firm Under Regulatory Constraint*, *American Economic Review*, Vol. 52, No. 5, 1962, pp. 1052–1069. Although widely cited and, indeed, often accepted axiomatically, the validity of the Averch-Johnson effect is not universally accepted. *See, e.g.*, Law, S., *Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities*, *International Journal of Economics and Finance*; Vol. 6, No. 8; 2014. While the empirical observations made in this paper might in places be explained by Averch-Johnson, the examination of the entry and exit of generation in both regulated and merchant environments in this paper shows that both models work comparably and effectively in exiting economically obsolete resources and replacing them with cost-effective new entry. As will be explored later, regulated models, however, do show a tendency, perhaps explained by Averch-Johnson, to embark occasionally on very expensive experiments, and evidence also suggests regulators are paying investors in rate-based generation a return that is not commensurate with their assumed risks.

[17] In economics and in public-choice theory, "rent-seeking" involves seeking to increase one's share of existing wealth without creating new wealth. Rent-seeking can result in reduced economic efficiency through poor resource allocation, reduced actual wealth creation and other undesirable outcomes.

[18] Going-forward costs include costs required to keep the facility in commercial operation such as general administrative expenses, fixed operation and maintenance cost, insurance, property taxes and labor or material expenses necessary to keep the facility ready to operate and produce energy. Going-forward costs also can include *prospective capital investments* that would be required to keep the generation facility in commercial operation, such as replacement of major equipment (e.g., turbines) or addition of equipment to comply with environmental regulations.

As described below, the options facing a regulated utility confronting the question of exit create incentives which can drive different, but equally undesirable, decisions. Certain scenarios may create an incentive to retain uneconomic resources that should be shuttered, while others can result in precisely the opposite outcome – retiring resources that still have economically useful life in favor of expanded investment in new rate-based resources. According to theory, because cost-of-service regulation biases decisions toward capital-intensive investments and because operating expenses are passed through to ratepayers, a profit-maximizing utility is indifferent to the operating expenses of different options.

Consider a regulated utility deciding whether to undertake a substantial capital investment in a marginally profitable generating facility in order to keep it in operation. One option might be to buy lower-cost capacity and energy from the market, the cost of which is regarded as an operating expense in the regulatory world. The efficient competitive market solution would be to retire the existing generation resource. However, because investing in the plant involves a capital expenditure and because the utility can earn a regulated return on that investment, the regulated utility is incented to retain and invest in its existing asset rather than retire its resource and buy from the market.

If one subscribes to the Averch-Johnson effect, the decision to make an uneconomic investment in an existing plant in lieu of purchasing power from a third party is predictable. Academics have hypothesized how this can happen because regulated environments can be structurally biased in favor of retaining capital once invested and thus reluctant and slow to retire and close assets which are no longer economic.[19] Given the competitive pressures facing the nation's coal fleet, some studies have tended to support this hypothesis[20] noting increasing environmental compliance costs and the "new normal" of persistently low natural gas prices.

Conversely, when the utility has the option to shutter a coal plant in favor of capital investment in a new plant, Averch-Johnson may work to quite the opposite effect by prematurely retiring depreciated (but still economic) capital in favor of an expanded rate base. The PJM markets have been charged with this same inefficiency, as some argue the markets are providing inadequate revenues (relative to a regulated construct) and thus are overly aggressive in retiring generation (for example, existing coal-fired generation).

This paper does not seek to prove or disprove any of the foregoing hypotheses, including the Averch-Johnson effect. Nevertheless, the academic debate is a helpful backdrop when considering the fundamental question posed by this paper: do empirical observations indicate whether markets result in efficient entry and exit outcomes for resources needed to assure reliability?

Resource Entry: Costs and Risk-Adjusted Returns in PJM Markets Compared to Regulated Environments

With notable exceptions, new entry generation in the United States over the past several years and for the immediately foreseeable future can be classified as investment in either (i) renewable or emerging technologies, or (ii) natural gas

[19] *See, e.g.*, Hsu, *Capital Rigidities, Latent Externalities*, 51 Houtson Law Review 720 (Feb. 2014). Hsu's observations on the "stranded cost" payments agreed to by state regulators as they transitioned in the 1990s from regulated capital to merchant capital is instructive to consider in light of sequels currently playing out in certain states as some legacy coal and nuclear units face obsolescence. Hsu notes wryly: "Transition relief, based on a misguided intuition, has made the obsolescence of capital everybody's problem. Everybody, that is, except the owners of obsolescent capital."

[20] *See, e.g.*, *Ripe for Retirement*, *The Case for Closing America's Costliest Coal Plants*, Union of Concerned Scientists (Nov. 2012) examined coal plants operating in the face of economics that should, accordingly to the study, have forced closure. The study concluded that the most so-called "ripe-for-retirement generators" were located "primarily in the Southeast and Midwest, with the top five (in order) being Georgia, Alabama, Tennessee, Florida, and Michigan." These states generally are operating outside organized wholesale electricity markets. Study online at: http://www.ucsusa.org/sites/default/files/legacy/assets/documents/clean_energy/Ripe-for-Retirement-Full-Report.pdf

combined-cycle plants. The section below compares new entry in regulated versus market regimes, first by examining other resource types, including renewable and emerging technologies, before turning to combined-cycle generation.

Emerging or Unconventional Technologies

Markets determine whether the theoretical promise of a new innovation is realized under real-world operating conditions.[21] This principle applies to low-capital resources such as renewables as well as large-scale, capital-intensive projects. Conversely, in a regulated environment, the incumbent utility stands as a gatekeeper to entry. Elements of the regulated structure (the Averch-Johnson effect) likely create disincentives for incumbent utilities to pursue emerging technology solutions if they involve a low capital outlay. Given a choice between increasing its operational costs, which are simply passed through without providing a return to the utility, versus investing more capital, the rational utility would chose to invest capital in order to realize greater returns.[22]

Other structural aspects of traditional regulated environments also may discourage investment in emerging technologies.

- Although a utility may be motivated to have ratepayers underwrite the theoretical proposition of an unproven technology, the attendant risk that regulators may deny rate recovery if the investment ultimately is deemed imprudent or unnecessary works to perpetuate conventional resource investment.[23]
- The value of grid benefits, such as energy or ancillary services, is opaque, making it difficult to evaluate the relative performance of the innovation compared to established or alternative technologies.
- The lack of competition or outright prohibitions against competition (due to the franchise monopoly nature of non-market environments) makes it difficult to test a variety of approaches.

In regulated environments, an unsuccessful innovation could be locked into a utility's rate base for years.[24] As evident from the examples noted in Table 1 below, unsuccessful innovation can prove a costly proposition considering the aforementioned bias in favor of large, capital-intensive projects, such as 21st-century nuclear plants and clean coal generation.[25] A large failed bet on one technology may crowd out willingness or funding to try an alternate technology that otherwise might have emerged as a true game changer.

[21] *See also*, Huntoon, S., *Battery Storage: Drinking the Electric Kool-Aid*, 36 *Public Utilities Fortnightly*, at footnote 3 (January 2016) ("Two-thirds of the country operates under competitive wholesale markets that can function as a check on bad ideas being charged to captive customers (of course captive taxpayers remain at risk).")

[22] The incentive structure of regulation thus favors a large capital investment (such as a new, large generating plant) ahead of a small one (such as less capital-intensive technologies or demand response that will reduce volumetric revenues). It also follows that a rational utility will be incentivized to take steps to block these alternatives where possible in order to preserve the need for its preferred larger-scale capital investments.

[23] *See, e.g.*, Lyon, Thomas P., "Regulatory Hindsight Review and Innovation by Electric Utilities", *Journal of Regulatory Economics*, Volume 7, pp. 233-254, 1995.

[24] For instance, Long Island ratepayers are still paying for Shoreham Nuclear Power Plant, the $6 billion nuclear plant that was completed in 1984 but never ran due to safety concerns. *The New York Times*, "Planning the Fate of a Nuclear Plant's Land," John Rather, January 1, 2009. Accessed January 22, 2016, from http://www.nytimes.com/2009/01/04/nyregion/long-island/04shorehamli.html?_r=0

[25] The case of "clean coal" or integrated gasification combined-cycle technologies in the United States provides a good recent example. Mississippi Power's long-delayed 582 MW Kemper County facility presently is projected to cost nearly $6.5 billion, compared to an expected $2.3 billion when regulators approved the project in 2010. Such a project seems highly unlikely to initiate in a market like PJM's, even taking into account generous subsidies from the Department of Energy, Internal Revenue Service and others. Furthermore, if one did commence, its cancellation well before commercial operation would be inevitable as transparent electricity market prices, driven lower by falling natural gas prices, would make the folly of continued construction funding abundantly evident.

Regulators are aware of these problems. Some have taken steps within their regulatory paradigms to enable newer technologies to come online. Some jurisdictions use constructs such as performance-based regulation, including multiyear rate plans and performance incentive mechanisms, to help overcome the traditional disincentives found in the regulated environment. Regulators examine these kinds of options with the hope of changing the investment decisions that usually result from cost-of-service ratemaking so as to increase adoption of demand response, energy efficiency, distributed resources and so forth. Not surprisingly, these programs tend to become quite proscriptive[26] because they often work at odds to the incentives motivating a monopoly utility. Still, for regulators charged with evaluating resource investment options, if located within an organized market they almost certainly will make better informed decisions having ready and transparent market alternatives from which to compare.

In markets like PJM's, innovative technologies, almost without exception, are investments with lower capital costs. Resources such as energy efficiency demand response, small-scale distributed generation, smart inverters, microgrids and battery storage represent the "cutting edge" in PJM. While such new technologies can be found to some extent in regulated environments, they also tend to define "cutting edge" to include investments that are larger (and riskier) by orders of magnitude: the latest generation in nuclear reactors, super-critical coal, coal gasification, carbon capture and sequestration and utility-scale renewable projects.

Next-Generation Nuclear and Coal

As shown below, the capital-intensive investments in innovative technologies made in regulated regimes are expensive from the standpoint of invested capital when compared to conventional new combined cycle.

Table 1. Comparison of Investment Costs for Next Generation Coal and Nuclear vs New Natural Gas

	Cost Comparison of Large Scale Generation				
	Project Type	Estimated Cost ($B)	Size (MW)	Estimated Investment Cost ($/kw)	Converted to $/MW-Day
Kemper County	Coal with carbon capture	$6.5	582	$11,168	$3,272
Crescent Dunes	Solar with molten salt storage	$0.91	110	$8,200	$2,402
Watts Bar 2	Nuclear	$6.1	1,150	$5,304	$1,554
Vogtle 3 and 4	Nuclear	$14	2,230	$6,700	$1,963
Prairie States	Supercritical Coal	$5.0	1,600	$3,125	$915
Comparison Generator Benchmark[27]	Natural Gas Combined Cycle			$1,400	$410

[26] For a more detailed examination see "Performance-based Regulation in a High Distributed Energy Resources Future" at http://www.synapse-energy.com/sites/default/files/performance-based-reg-high-der-future.pdf

[27] This value was offered in 2015 testimony to the Public Utilities Commission of Ohio as representing a working benchmark used by IHS CERA. It is referenced in Table 1 only as a generalized point of comparison. In fact, other firms publish ranges lower than this value. *See, e.g.*, Energy & Environmental Economics (E3), *Capital Cost Review of Power Generation Technologies Recommendations for WECC's 10- and 20-Year Studies*, at 17-18 (March 2014) online at: https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf. As discussed later in this paper, actual new combined cycle entry in PJM (both merchant and regulated) is coming on-line at costs well below this value.

The conclusion from this table is clear. Investment in high capital, high risk and experimental technologies will not find footing in PJM as they might in regulated regimes. The price of these projects is intolerably high in contrast to the natural gas combined-cycle alternative that today's market offers.

Storage

A cost-effective way to store large volumes of electricity has been described as the industry's "holy grail" which, if found, would transform the industry.[28] Despite the broad applicability of grid benefits from storage, the current technology is very concentrated in areas with competitive markets. Approximately 85 percent of the non-pumped-hydro energy storage in the United States is deployed in competitive markets with over half the total located in PJM.[29]

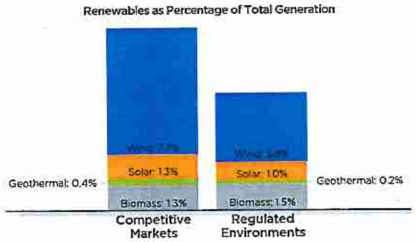
Table 2. Energy Storage in the United States

Market	Energy Storage Deployed (MW)
California	57
ISO-NE States	5.0
New York	28.0
PJM States	231.2
Texas	44.3
Total, Competitive Markets	344.1
Total, Nationwide	401.0

Renewables

Renewable resource investment is driven as much by tax, financing and other social and environmental policies as it is by economic fundamentals. Nevertheless, comparing non-hydro renewable-resource penetration does suggest that lower economic barriers to entry as well as opportunities to earn operating reserve and frequency regulation compensation, which are both found in market environments, help to attract renewable investment. Figure 2 below shows that as of 2015, renewable penetration is 10.6 percent of total generation in market environments versus 6.5 percent in non-market areas.

Figure 2. Renewable Penetration Levels (2015)[30]



[28] See, e.g. Enskog, D., *Resolving Energy Storage: the Sector's Holy Grail?*, Credit Suisse Newsletter (May 8, 2005) online at: https://www.credit-suisse.com/us/en/news-and-expertise/economy/articles/news-and-expertise/2015/08/en/resolving-energy-storage-the-sectors-holy-grail.html.

[29] Data from GTM Research/ESA U.S. Energy Storage Monitor.

[30] Based on national generation collected from SNL Financial, accessed March, 2016. Comparison ISO/RTO areas vs. non-ISO/RTO areas.

Demand Response

Several attributes of demand response fundamentally distinguish it from typical generation investment made under a traditionally regulated model. Demand response usually involves minuscule capital investment compared to a new generating plant. It reduces the metered flows of wholesale electricity and receives compensation for providing this demand reduction service. This payment model contrasts with generation investors whose returns increase the more kilowatt-hours are flowed. While demand response can never completely substitute for electric generation, it can be a highly effective and valuable means of managing peaks in demand. Many would argue that demand response, like renewables, has been heavily incentivized by subsidies and the level of penetration is driven by these subsidies as well as other societal priorities. These subsidies undeniably have a pronounced effect, as do proscriptive policies in the regulated environment. Nevertheless, the markets serve as an open, transparent platform for demand response to demonstrate its value and for policymakers to evaluate the costs of the policies they support.

Because the entirely different payment model and incentives associated with demand response do not coexist comfortably with the traditional integrated utility model, it again should come as no surprise that the level of demand response overwhelmingly favors market over regulated environments.

Table 3. Potential Peak Reduction in U.S. Demand Response Programs (2014)[31]

Market	2014 Potential Peak Reduction (MW)
California	2,316
ISO – New England States	2,487
New York	1,211
MISO	10,356
PJM States	10,416
Texas	2,100
Total, Competitive Markets	28,934
Total, Nationwide	31,191

The foregoing observations around renewable, demand response and alternate technologies suggest that the open access of the PJM markets provides a platform on which any solution can demonstrate its value. The PJM markets have spoken on the value proposition offered by the latest-generation nuclear and coal technologies. (As explored in Part 2, whether the market should serve as the final word on such questions is open for debate.) Additionally, although PJM and its ISO/RTO peers appear more successful than other areas in attracting innovative and flexible supply and demand resources, drawing any firm conclusions about the relative benefit brought by markets is difficult when the investment decision, in many

[31] FERC (2015) Assessment of Demand Response and Advanced Metering, online at http://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf with additional data from various EIA and ISO/RTO reports.

instances, depends heavily on subsidy. Instead, evaluating new, natural gas-fired combined-cycle investment is a more enlightening comparator.

New Combined-Cycle Plants

In much of the United States a natural gas combined-cycle plant is today's most cost-effective new electricity generation investment. This section considers three important questions arising from this development.

1. Are PJM markets bringing new combined-cycle generation online at a higher or lower total cost than under full cost-of-service regulation?
2. In making such comparisons, how do we measure the value or cost that comes from allocating risk either to investors in the merchant paradigm or to ratepayers in the regulated paradigm?
3. Once the value/cost of risk is accounted for, can we conclude that PJM markets are better at forcing cost control and/or whether PJM's market-clearing dynamics, which cause capital to compete for returns, force a downward pressure on investor returns?

Investing in a power plant presents risks in many forms. All risks have costs that are borne by some party. To illustrate, assume an expensive Italian sports cars dealer is offering its flagship model at two prices: (1) at $120,000 with only the most minimal warranty allowed by law or (2) at $130,000 with a full, bumper-to-bumper repair and maintenance warranty for the 10-year life of the vehicle. Depending on one's assessment of the likelihood and cost of repair and maintenance, $130,000 could be a much more attractive proposition for a buyer than the option of saving $10,000 up front but assuming the going forward costs of maintenance and risks of repairing an expensive sports car.

In the wholesale electricity realm, the unbundled load serving entity (LSE) and the traditionally integrated utility fall into the role of sports car buyers in our example. The analysis below suggests that customers of a traditional integrated utility company operating under rate regulation may be paying a lower upfront price for new combined-cycle generation but they bear the additional risks (e.g., construction, market, operating, etc.) associated with building and operating that plant over its life. This buyer of generation compares to the customer who elects to pay $120,000 for the sports car and assumes all ongoing repair and maintenance risk.

In contrast, although LSEs in PJM appear to pay a comparable or marginally higher upfront cost for new combined-cycle plants, any premium paid assures that all market, price, operations, technology and regulatory risks remain with the generation asset investor and are not assumed by the LSE (and its retail customers in turn). Which is the better deal? That depends on pricing the cost of this risk (or the value in avoiding this risk) and then adjusting the purchase price accordingly.

This section first examines costs (the purchase price in this example). It tries to establish representative all-in costs (including debt service and a return on equity) for new combined-cycle generation in both merchant and regulated cases. It examines recent merchant entry in PJM and recent regulated entry both in PJM (Virginia) and outside PJM (Florida) to identify the equivalents for both the $120,000 and $130,000 prices used in the sports car example above. In electricity terms, this price can be expressed in an annual revenue requirement ($/MW-year) and in dollars per installed kilowatt.

Having identified a range of all-in costs representative of each environment, the paper considers risk allocation and the expected returns to investors – each class presenting a dramatically distinct risk profile. As noted, rate regulators calculate and establish revenue requirements based on a certain rate of return on the rate base. This return should account for the fact that investment risks are largely allocated to ratepayers in regulated environments. This situation stands in marked contrast to merchant investment in PJM where the market provides varying and uncertain revenues and return on the

equity investment in a new generating asset. Additionally, the return realized by merchant investors must account for the costs they assume in wearing or managing all risks arising from developing and operating the asset.

In theory, the allocation of risk to the investor as opposed to the customer is more efficient and should lower costs to the consumer because risks will resides with parties positioned to manage those risks, which ultimately may not lie with the merchant investor but with third parties with whom the merchant can transact to lay off risk (for a price). The section concludes by discussing the tools available to manage such risks both within PJM's liquid markets and in supporting secondary markets.

In short, overall costs and returns on invested capital differ in competitive electricity markets from returns in regulated systems. What do these differences say about the competitiveness of one system compared to the other? Does empirical evidence demonstrate that competition forces investors in market environments to lower costs or accept a lower return on equity compared to the regulated monopoly?

Comparing Cost of New Entry in Differing Environments

Recent combined-cycle development in Virginia represents entry under a full cost-of-service paradigm. These new plants have been praised by the industry as extremely well executed by the utility (Dominion Virginia Power) and cost effectively managed by the State Corporation Commission.[32] The regulatory process that evaluated and accepted these resources also benefits from unusual transparency as each of the three examples considered below (Brunswick County, Bear Garden and Warren County) were approved with separate rate riders that state a specific annual revenue requirement for each plant. While just a "snapshot," the Virginia plants would seem to reflect the operation of regulation at its best. Therefore, they serve as a fair representative of the overall regulated model against which to compare PJM's market-driven outcomes.

Perhaps surprisingly, determining all-in costs for merchant investment in PJM is more complex. Identifying revenues received by new entry clearing PJM's capacity market is straightforward. The analysis below uses the clearing prices from the 2015/2016 Base Residual Auction[33]. These values for the constrained Eastern MAAC[34] region calculated at $167 per MW-day and for the rest of the RTO at $136 per MW-day. These values then were annualized (multiplied by 365) to arrive at an annual revenue value. However, merchant investment in PJM is not supported solely by revenues received from the capacity market but additionally by net revenues (revenues less costs) realized by selling energy and ancillary services.

Determining infra-marginal returns realized by a generator in PJM's energy and ancillary service markets is a function of the unit's capacity factor, expected locational marginal prices (LMPs) and its operating costs (fuel, variable operations and maintenance). To determine the net energy and ancillary service market revenues that might contribute (along with capacity market revenues) to the fixed costs and return to the asset investor, PJM modeled a cost of new entry for a 656 MW natural gas combined-cycle generator based on 2012-2014 LMPs. In Table 4 below, the first column (PJM Capacity,

[32] In December 2015, *Power Engineering* magazine recognized Warren County as its "Project of the Year" and "Best Natural Gas Fired Project." Online at: http://www.power-eng.com/articles/2015/12/power-engineering-renewable-energy-world-name-2015-power-gen-international-projects-of-the-year.html

[33] This auction does not reflect the additional performance requirements and other rule changes included in the Capacity Performance initiative. It was selected because 2015/16 more closely aligned to the commercial operations dates of the comparison units in Virginia and Florida.

[34] The Eastern MAAC area generally encompasses New Jersey, southeastern Pennsylvania, and the Delmarva peninsula.

Energy and AS Revenues (based on net energy revenues)) reflects both modeled revenues and operating costs.[35] Examples in PJM are shown both in Eastern MAAC and in the rest of the RTO.

The second column shows the gross cost of new entry as determined by the auction planning parameters for PJM's 2018/2019 Base Residual Auction. It serves only as a reference price in PJM's capacity market and is levelized over 20 years (as opposed to 30 years for the Virginia and Florida figures).

Finally, as an added point of comparison, Table 4 below shows approximate revenue requirements for three recent combined-cycle projects in Florida.[36] These projects show costs higher than those in Virginia and generally higher than the range of plausible costs in PJM. As in Virginia, consumers in Florida are paying these costs plus assuming all other investment risks. But, unlike Virginia, Florida is neither a part of nor adjacent to an organized wholesale market. While many factors undoubtedly could explain why new investment seems to be coming online in Florida at a higher notional cost than in Virginia, it can be surmised that Virginia benefits from the alternate supply options, transparency and discipline offered by PJM's competitive markets. Florida's isolation from an organized market might impede regulators from having a full range of alternatives to consider and to provide a competitive check on regulated new build. These themes are explored further in Part 2.

Table 4. Comparison of New Natural Gas Generation

	PJM[37]				Virginia[38]			Florida[39]		
	PJM Capacity, Energy and AS Revenues (based on net energy revenues)		PJM Gross Cost of New Entry[40]		Brunswick County	Bear Garden County	Warren County	Cape Canaveral	Riviera	Port Everglades
	RTO	EMAAC	RTO	EMAAC						
Annual Revenue ($/MW-yr)[41]	124,029	151,418	130,425	132,200	118,810	120,696	97,330	137,750	187,200	169,146

[35] Revenues are based on three-year historic averages.

[36] This information was obtained from Florida Public Service Commission docket number 120015-EI and the settlement approved on December 13, 2012.

[37] Capacity revenues are based on a clearing price of $136/MW-day in the rest of the RTO and $167/MW-day in Eastern MAAC from the 2015/2016 Base Residual Auction.

[38] Based on 2015 rate rider filings for the 1358 MW Brunswick County facility, 580 MW Bear Garden facility, and 1342 MW Warren County facility. Annual revenue calculations are based on projected annual revenues levelized over 30 years, using a 7 percent discount rate.

[39] Based on annual revenue adjustments of $165.3 million beginning June 2013 for the 1200 MW Cape Canaveral facility, $234 million beginning June 2014 for the 1250 MW Riviera Beach facility, and $216 million beginning June 2016 for the 1277 MW Port Everglades facility. These amounts are subject to year-to-year adjustment, and are used here for illustrative purposes only. *See*, Settlement Agreement approved on December 13, 2012 in Florida Public Service Commission Docket No. 120015-EI.

[40] PJM 2018/2019 BRA Planning Parameters online at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-bra-planning-parameters.ashx.

[41] For PJM, this number represents expected annual revenue as described above based on values from the noted years. For Virginia and Florida, this figure represents a 30 year levelized annual revenue requirement for these units. Out of market revenues (uplift) as well as performance assessment debits or credits under PJM's new Capacity Performance design are examples of market design features that may increase or decrease total net revenues realized by a

It is difficult to compare all-in costs accepted by a regulator for new combined-cycle entry with the same costs incurred by PJM (and in turn its wholesale customers) for this same resource. This analysis necessarily is simplified and does not control for all variables that might fully explain outcomes. Accordingly, any findings should be regarded as indicative and not in any way definitive.

Markets are attracting significant new investment. In PJM, over 15,000 MW of new generation is expected to come online in 2016. This investment is being made based on a range expected market revenues of between $124,000 and $151,000 per MW-year. In Table 4 above, the second column (EMAAC) is the high end of the range and reflects higher capacity revenues in constrained capacity areas and market revenues based on three-year historic averages, including energy and ancillary services values that are probably atypically inflated due to high prices experienced during the Polar Vortex period.

These estimates seem reasonable when compared to regulated generation projects of similar size and vintage. The projects in Virginia have an approximate annual revenue requirement of between $97,000 and $121,000 per MW-year while those in Florida come in approximately between $138,000 and $187,000. These calculations in Table 4 do not attempt to control for geographic costs differences in siting and construction. The costs in the locales in which the Dominion Virginia Power plants were built likely compares more closely to average costs in PJM (*i.e.*, the PJM RTO), and not PJM's Eastern MAAC.[42] More important, the PJM merchant annual revenue and installed kW values are paid across *all* resources in the system – both to the marginal, highly efficient new entrant and to the older, existing and lower-capacity-factor legacy resources. The values, however, in the regulated cases are plant-specific. The average cost (considering both new and existing units) in Virginia and Florida reasonably can be expected to be higher than the values stated in the table for the state-of-the-art, new plants.

While the table attempts an "apples to apples" comparison of new combined-cycle entry under each model, at best it offers a "red versus green apple" comparison. Nevertheless, the comparison suggests both environments establish new entry at roughly the same costs – with some nominal advantage in favor of the regulated paradigm (at least in Virginia). But, comparing on their face the notional costs between PJM on one hand, and Virginia and Florida on the other, ignores one critical but difficult to quantify cost distinction not captured in the values in Table 4

It is an axiomatic law of finance that risk has cost. If one could price all risks attendant to developing, constructing and operating a new power plant over its economically useful life, one could compare the notional values in Table 4 to "risk-adjusted" values to determine which model delivers consumers the overall better deal when procuring new combined-cycle resources. The nominal advantage seen in Table 4 in favor of the regulated model might disappear, and the balance could shift in favor of the merchant model. The difficulty, of course, lies in pricing this risk. The challenge is heightened now when

generator. No estimates of these speculative and less material elements were included in arriving at the indicative values representing the "annual revenue requirements" paid to resources by the PJM markets.

[42] By the same token, the higher costs seen with the reported Florida projects are likely explained to some degree by higher costs associated with siting, permitting and developing generation as compared to Virginia. Other locational differences also impact these figures. For example, Florida requires natural gas generating plants to have firm fuel delivery contracts, which serves to escalate their costs relative to combined cycles in other parts of the country. Because the values reported here are intended simply to be indicative, they do not attempt to try to control for locational cost differences. A general sense of the degree such costs vary from one region to the next can be found in *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, U.S. Department of Energy, Energy Information Services (April 2013).

today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk.

The following discussion examines how the financial equity markets regard firms operating in merchant versus regulated environments and whether differences here offer insight useful to valuing or pricing the various risks faced when investing in new generation under differing regulatory conditions (merchant or cost-of-service).

Considering Risk and the Cost of Risks Associated with Generation Investment

As with all capital allocation decisions, resource investment decisions are based primarily on the risk-adjusted expected returns of investment alternatives. Understanding the difference in the electricity industry between risk-adjusted expected returns for merchant generation investment and for regulated generation investment is important because each model allocates this risk very differently. This section employs economic and financial models to analyze the risks of and returns on merchant and regulated investment. For readers without a financial background, the results are summarized as follows:

Conclusions

1. Because they do not have ratepayers, the merchant generator must hold and manage all investment risk and thus its cost of equity is higher than for a regulated utility. However, in stronger economic periods, the difference in the cost of equity between merchant investment and regulated utilities is smaller than in weaker economic periods, indicating that investors are less inclined to make a riskier merchant investment during weaker economic periods.

2. Actual returns indicate that merchant generation company returns are statistically consistent with their risk-adjusted expected returns. On the other hand, actual returns for regulated utilities are statistically higher than their risk-adjusted expected returns. It is unclear why there is a significant difference in actual returns over risk-adjusted expected returns that benefits investors in regulated generation.

   Analyses of the cost of equity for merchant generators and regulated utilities indicate that financial markets properly seek higher returns from riskier merchant generation investments and confirm that actual returns on merchant generation investment are consistent with such required returns. In addition, those same analyses revealed a significant phenomenon regarding returns for regulated utilities. Based on allowed rates of return on equity in recent cases, regulated utilities exceed the estimated cost of equity by a statistically significant 1.75 to 2.68 percentage points, depending on the model used in each analysis. It is unclear why actual regulated investment earnings are above the risk-adjusted expected rate of return.

3. Overall, economic and financial principles would expect actual returns for merchant generation companies to be higher than on regulated utility investments due to the higher risk attributed to merchant generation investment. However, analyses of actual returns supports that regulated utility companies are earning more than merchant generation companies despite the lower risk profile of regulated utility investments.

Allocation and Pricing of Risk: Regulated Versus Merchant Investment

As noted, one profound difference distinguishing competitive from traditional electricity markets is how the risk of investment is allocated. In a traditional cost-of-service regime, ratepayers underwrite the investment in public utility assets. The regulator is responsible for protecting ratepayers' interest in assuming only the risks of prudently made, used and useful investments. This is a difficult job and one that suffers from certain inherent structural flaws that regulatory economists and policymakers have examined often and in great length over several decades.

A central question is whether the regulatory paradigm to support electric infrastructure investment respects one of the basic tenets of finance theory regarding risk: that the most efficient outcomes result from structures (law, regulation, private contracting, etc.) that place a particular risk of a transaction on the party that can most efficiently manage that risk. In the context of investing in a long-lived, capital-intensive power plant, the question in applying this rule is whether the owner/operator or the ratepayer is in the best (i.e., most efficient) position to manage (i.e., mitigate, hedge or insure) risks attendant to developing and operating the power plant.

Those advocating the traditional rate-regulated model believe that most risks of electric infrastructure investment are efficiently placed on ratepayers. This belief accepts that having ratepayers underwrite utility investment efficiently allocates the risks associated with that investment because by their nature those risks are most efficiently distributed widely among all ratepayers. Under this paradigm, to protect ratepayers from monopoly rents, the public utility's allowed return on equity in rate base is established by the regulator.

The *Hope/Bluefield* doctrine is a well-established utility ratemaking standard that states in part (emphasis added):

> *...a public utility is entitled to such rates as will permit it to earn a return on the value of the property...to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are <u>attended by corresponding risks and uncertainties</u>.*[43]

In setting allowed return on equity, regulatory proceedings will estimate the utility's cost of equity using methods like discounted cash flow, capital asset pricing or risk premium models. In these proceedings, the regulator is tasked with setting a reasonable risk-adjusted allowed return on capital investment for the utility, understanding that much of the risk has been shifted to the ratepayer.

Conversely, under the market model merchant power developers compete for uncapped returns that they can realize through their performance in a market like PJM's.[44] While the merchant's return on its invested equity is uncapped, it also is more variable and uncertain than regulated returns. Along with this uncertainty, merchants shoulder the risks associated with the plant's operation and its viability in the face of a changing competitive fleet, technological advancement, changing rates of load growth and dynamic fuel prices.

The same risks associated with developing and operating a power plant exist in both merchant and regulated paradigms. In order to understand whether competitive markets or regulators allocate and price this risk more efficiently, it helps to start with a simplified understanding of the sources and attributes of investment capital.

Methodology

This analysis estimates a firm's cost of equity capital using the seminal CAPM first developed by Sharpe (1964)[45] and the multifactor models that were formulated later by Fama and French (1995) and Carhart (1997)[46] to incorporate effects

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[43] *Bluefield Water Works and Improvement Company vs. Public Service Commission, 262 U.S. 679 at 692-93 (1923) ("Bluefield"). See also, Federal Power Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope").*

[44] Practically speaking, hypothetical returns in competitive power markets are not absolutely uncapped. All such markets in the United States, including PJM's, set system offer caps in both capacity and energy markets that serve as a check against wild price excursions and the potential exercise of aggregate market power among suppliers.

[45] William F. Sharpe (1964) Capital asset prices: a theory of market equilibrium under conditions of risk," Journal of Finance 19, 425-442.

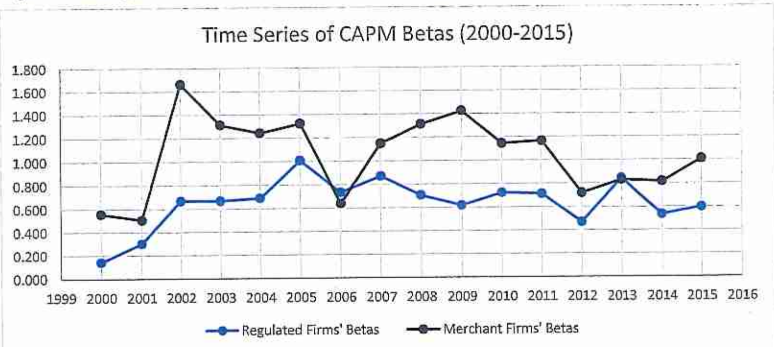
related to firm size, relative valuation and momentum. A more detailed explanation of the methodology and data sources can be found in Appendix A.

The results were the alphas and betas of the CAPM (and for the multifactor Fama-French plus Momentum model as a robustness check) for each of the nine publicly traded merchant firms and 22 regulated firms. The firms used are listed in Appendix A.

CAPM Results

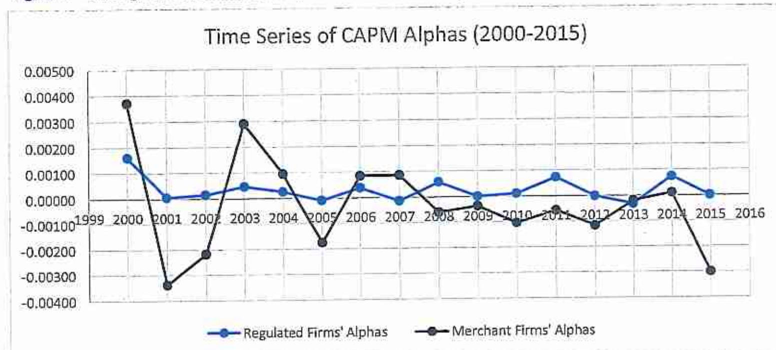
The main results based on the simple CAPM are summarized in the following two time-series graphs of historical beta and alpha (Figure 3 and Figure 4).

Figure 3. Average Annual Estimates of Beta for Merchant and Regulated Firms



[46] Eugene F. Fama and Kenneth R. French (1995) "Size and Book-to-Market Factors in Earnings and Returns," *Journal of Finance* 50, pp. 131-155; and Mark M. Carhart (1997) "On Persistence in Mutual Fund Performance," *Journal of Finance* 52, 57-82.

Figure 4. Average Annual Estimates of Alpha for Merchant and Regulated Firms



The above two graphs show the annual average beta and alpha estimates for the regulated and merchant firms during 2000-2015. Each year, the beta estimates for every firm in the two groups are averaged on an equally weighted basis to obtain annual values of risk (beta) and risk-adjusted "excess" returns (alpha).

A review of these two graphs reveals four key findings related to the CAPM analysis.

1. Average merchant betas are significantly higher than average regulated CAPM betas (1.062 versus 0.642, or 65 percent higher). Average merchant betas based on the Fama-French plus Momentum model also are higher but to a lesser degree (1.081 versus 0.778, or 39 percent larger). There is evidence that the historical betas are mean-reverting, but, even after accounting for a Bloomberg-type adjustment for this effect, a forward-looking estimate of beta based on the most recent 2015 data yields a forecast of 1.027 for average merchant firm beta and 0.751 for average regulated firm beta (still 37 percent higher).[47]
2. Merchant betas seem to converge to regulated betas in better economic conditions (e.g., 2005-2006, 2012-2013) and diverge from the regulated betas in weaker economic times (2002, 2008-2009, 2015). This effect could be consistent with the notion that merchant firms face greater risk during weak economic situations but face risks similar to regulated companies when the economy is doing well. Thus, there is an asymmetry in how investors react to the riskiness of merchant firms (versus regulated firms) during times of economic weakness.
3. Merchant alphas are much more volatile than regulated alphas. On average, merchant alphas are negative but not significantly different from zero (at -4.1 bps per day) while regulated alphas are much steadier and significantly positive (+2.9 bps per day). This 7.0 bps per day difference is statistically and economically significant (with a t-statistic of 7.0 and a p-value less than 0.0001). The alpha results suggest that merchant firms are generating returns equal to their expected returns, and thus alpha is not different from zero. However, regulated firms are generating positive alphas each year and indicate that they are providing returns *in excess* of their required returns. Put another way, one can interpret the positive and significant alphas as an indication that

[47] Bloomberg data services computes an "adjusted beta" to account for possible "mean reversion" in beta estimates. The equation adjusts the beta estimated on historical data via the following equation: adjusted beta = 0.35 + 0.67 * historical beta. In the current context, one can estimate an historical beta, using daily data for 2015, and then adjust this historical beta using the above equation to generate a more forward-looking estimate of a firm's beta.

their required returns do not adequately reflect the risks these firms face whereas the merchant firms' results suggest that risk is priced more accurately. In effect, investors in regulated firms are receiving a "free lunch" while investors in merchant companies are receiving a "fairly priced lunch." The above analysis cannot identify why there is a distortion in the way the market prices the risks of regulated versus merchant firms, but it clearly documents that there is a significant difference, which benefits investors in regulated firms' equity.

4. Based on the CAPM analysis, Table 5 through Table 7 below shows the estimated cost of equity for regulated utilities and merchant generators. The average beta for each group was taken from the above analysis, which is based on nine merchant firms and 22 regulated firms during 2000-2015. The resulting cost of equity is calculated according to the CAPM formula: the risk-free rate plus beta times the market equity premium. For the risk-free rate, the long-term 1926-2015 average of one-month U.S. treasury bill rates was employed (3.37 percent). The market risk premium of 6.36 percent is based on an estimate reported in Mehra and Prescott (2008) using long-term average U.S. stock return data from 1889-2005.[48]

Table 5. Simple Capital Asset Pricing Model Cost of Equity Estimates, Historical Beta

	Risk-Free Rate	Market Risk Premium	Historical Beta	Implied CAPM Cost of Equity
Merchant	3.37%	6.36%	1.062	10.13%
Regulated	3.37%	6.36%	0.642	7.45%

Table 6. Simple Capital Asset Pricing Model Cost of Equity Estimates, Adjusted Beta

	Risk-Free Rate	Market Risk Premium	Adjusted Beta	Implied CAPM Cost of Equity
Merchant	3.37%	6.36%	1.027	9.90%
Regulated	3.37%	6.36%	0.751	8.15%

Table 7. Fama-French Plus Momentum Cost of Equity Estimates

	Risk-Free Rate	Market Risk Premium	Beta	Implied Cost of Equity
Merchant	3.37%	6.36%	1.081	10.24%
Regulated	3.37%	6.36%	0.777	8.31%

The results show the estimated cost of equity for regulated firms is 268 basis points lower than for merchant firms under the simple CAPM using historical betas, 175 basis points lower under the simple CAPM using adjusted betas, and 193 basis points lower under the Fama-French plus Momentum model. Those substantial differences in estimated cost of equity are entirely expected, given the different risk profiles of the two types of firms.

[48] Rajnish Mehra and Edward C. Prescott (2008) "The Equity Premium: ABCs." *Handbook of the Equity Risk Premium.* (Elsevier, North-Holland: Amsterdam and Boston) 1-36.

However, the 9.78 percent average allowed return on equity on rate base in recent rate cases[49] is incongruous with the above results. Under the *Hope/Bluefield* standard, the allowed ROE on rate base for a regulated utility should be equivalent to the cost of equity for the utility and reflect returns realized by other business undertakings which are "attended by corresponding risks and uncertainties."[50] Therefore, based on the above results, average allowed return on equity on rate base for a regulated utility should range somewhere between 7.45 percent and 8.31 percent. The 9.78 percent average allowed return on equity on rate base in recent rate cases is 147 basis points above that range. In short, the consistently positive alphas suggest strongly that the utilities were overearning during that period. In contrast, the alphas of merchant firms over that period were not significantly different from zero.

Analyzing Options Offers Additional Support to PJM's Findings

Practitioners and academics typically examine both beta and option volatility to assess a stock's riskiness. Therefore, as a check on the foregoing beta results, PJM examined options pricing data based on currently traded options on five merchant firms and 15 regulated firms.[51] This approach offers another way to assess the relative riskiness of these two groups as measured by the standard deviation, or volatility, of annualized returns. PJM extracted from the options data the implied volatilities for these firms as well as the historical estimates of these volatilities based on 30, 60, and 90-day histories of stock returns. This approach offered the advantage of not requiring the use of an asset pricing model, like the CAPM, and was thus simpler to compute. As noted earlier, this volatility measure captures a stock's total risk, which includes both systematic risk relative to the overall market and "idiosyncratic" or firm-specific risk that in theory can be diversified away.

In addition to the historical volatilities presented later based on past stock return data, options data can provide a forward-looking view of what investors think the riskiness of a firm's stock will be in the future. Therefore, the "implied" volatility, reported in Appendix A, uses option pricing theory first developed by Black and Scholes (1973) to extract from options prices what investors expect a stock's volatility will be over the life of an option.[52] PJM collected these data from Bloomberg for call options closest to the stock prices of their respective stocks that have two-to-four month maturities.[53]

The implied and historical volatilities for merchant firms range from 2.8 and 3.9 times larger than the volatilities of regulated firms' options. This confirms the earlier beta analysis which showed that merchant firms are perceived as much riskier than regulated firms. Thus, one would expect merchant firms to earn a much higher level of return than the firms that are more tightly regulated. However, the opposite seems to be true as the consistently positive alphas for regulated fims indicates these companies are earning returns higher than what they would be expected to earn given their much lower level of risk.

Conclusion: What Does CAPM and Options Analysis Say About the Relative Pricing of Risk?

The results of the foregoing examination of investment risk and how equity and options markets price this risk must be considered with caution. Comparing stock price volatility between publicly traded regulated utilities and merchant generators serves only as a proxy representation – and one with important limitations – for the different risk profiles facing

[49] The average allowed return on equity of 9.78 percent was derived from 2014-2015 rate cases for 34 electric utilities as reported in November 2015 by Public Utilities Fortnightly. *See* https://www.fortnightly.com/sites/default/files/article_uploads/1511-CW-2015-Rate-Cases-fig-1.pdf. This sample of 34 utilities is not the same sample of utilities used in the CAPM analysis above. Therefore, the 9.78% average allowed return on equity should be viewed as indicative only.

[50] *See*, note 43 *supra*.

[51] The specific firms are identified in Appendix A.

[52] Fischer Black and Myron Scholes (1973) "The Pricing of Options and Corporate Liabilities," *Journal of Political Economy* 81, 637-659.

[53] These options are typically referred to as "at the money" options and usually are the most actively traded options for a stock.

a generation investor in a merchant environment and one in a regulated environment. One such limitation is that stock prices move for many reasons. For example, the market's assessment of the capability of one firm's management relative to another's will contribute to the behavior of each firm's stock price. Importantly, there are no stocks that track just merchant generation to compare with ones tracking just regulated generation. Stock prices reflect the total business of the public company, and public companies can be comprised of several diverse business lines. While this point was considered in selecting the regulated comparator companies, these regulated utilities also are engaged in transmission, distribution and retail electricity businesses in addition to owning and operating generation. Whether these added businesses (beyond generation) calm or contribute to volatility of the regulated utilities' stocks can be debated. Finally, the data sample for merchant companies is small and, as described immediately below, considerable new generation investment is coming into PJM from private developers and not publicly traded merchants.

Even taking into account the foregoing limitations, the significant variances in beta and alpha between regulated and merchant firms (further supported by the analysis examining implied and historical option volatilities) cannot be summarily dismissed. While this work does not prove that regulators are over-compensating for the risks borne by utility investors building generation under cost of service, the analysis is sufficiently compelling to raise that possibility and to warrant further inquiry. Moreover, when revisiting the notional costs comparisons of combined-cycle investment in PJM, Virginia and Florida in light of these findings, it does appear that once risk is valued, consumers of merchant generation in PJM are obtaining electricity on highly favorable terms.

Recent Actual New Investment in PJM

To the extent regulators are valuing the risks attendant to generation investment differently than organized electricity markets like PJM's, the question is: who is getting it right? One possibility is that organized electricity markets are failing to offer sufficient revenue to compensate merchant investors adequately for the risks they assume. This is a fair question to ask, given that PJM's markets are not typical ones where price formation is simply a function of supply and demand.

Actual evidence shows that PJM has successfully attracted significant new merchant investment in generating plants, both new entry and upgrade to existing facilities, during the time it has operated a forward capacity market. Public information available on financings established to support investment in PJM in the last several years suggests that banks and other lenders have evolved innovative structures particularly responsive to PJM's capacity and energy market designs. Debt and equity capital is being attracted to these structures, which are successfully closing and leading to new merchant combined-cycle investment.[54] Below are ten leading examples in PJM of these merchant-structured financings:

- Panda Power – new 829 MW Liberty Station (purchased from Moxie Energy) in Bradford County, Pennsylvania.
- Panda Power – new 1124 MW Hummel Station in Snyder County, Pennsylvania.
- Panda Power – new 778 MW Stonewall Station in Loudon County, Virginia.
- Panda Power – new 829 MW Patriot Station in Lycoming County, Pennsylvania.
- CPV – new 700 MW Woodbridge Energy Center in Woodbridge, Virginia.
- Calpine – new 309 MW Garrison Energy Center in Dover, Delaware.

[54] Despite claims to the contrary, actual evidence of new combined-cycle investment in PJM shows that the overwhelming majority of this investment is merchant in character and not plants supported by rate base, municipal bonds or long-term generation and transmission cooperative contracts with distribution cooperatives. See "New Generation in the PJM Capacity Market" (2016) by Monitoring Analytics, online at http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf

- Oregon Energy Center – new 799 MW facility in Oregon, Ohio.
- Lordstown Energy Center – new 949 MW facility in Lordstown, Ohio.
- Middletown Energy Center – new 475 MW facility in Middletown, Ohio.
- St. Joseph Energy Center – new 700 MW facility in New Carlisle, Indiana.

This list is by no means exhaustive. For the years 2010-2015, approximately 134,000 MW of proposed natural gas generation entered the PJM queue. There now are approximately 74,000 MW in active development, 19,500 MW in service, 3,500 MW in partial service and 35,000 MW under construction.

Given the level of capital being attracted to PJM, it seems highly implausible to claim the market is not compensating merchant investors enough for risks they assume.

Markets like PJM's Provide Tools for Investors to Manage Risk

Why might risk-adjusted returns realized by merchant investors be lower than risk-adjusted returns paid to the regulated investor? The discrepancies shown above in comparing CAPM metrics might be attributed to regulators overcompensating regulated firms for the risks they assume. Persistent mispricing of the risk assumed by the regulated investor may occur because regulators undervalue the certainty to the investor of a fixed return over the full life of the asset, regardless of what that actual level might be. There is tremendous value to the investor in having a fixed and certain revenue stream over the life of the investment – a value that is only increased in times when the industry is facing unprecedented uncertainty, as many claim it is today.

It is also possible that allowing investment capital to compete for projects results in merchant investors accepting lower risk-adjusted returns in PJM. But it might be the case that the overall cost of this risk is reduced by allocating it properly to parties best positioned to manage and reduce this risk. To consider this third possibility, start with the following first order principal: markets place risks associated with an investment on the asset investor to manage and not on the consumer – who is in no position to manage these risks. Born from this allocation are secondary markets for risk that offer physical and financial risk management tools allowing the transparent transfer of risk, at least cost, to the party best able to manage it.

A risk management "ecosystem" has evolved to assist investors in managing investment risks by providing further avenues to lay off risk where the price to the investor in doing so is attractive as opposed to continuing to hold the risk. Through these tools, various risks (such fuel price, interest rates, operating risks, electricity prices, etc.) can be housed (for a price) with firms whose business design or position in the market allows them to manage a particular risk more efficiently than the asset owner and operator could do itself. Such firms include insurers, banks, trading firms, swap dealers, lenders and other market participants. Notably, these actors and activity while prevalent in market environments with merchant investors[55] are much less evident in regulated environments where risk management tools are largely superseded by a structure that allocates most investment risk to the aggregate consumer base.[56]

[55] In the PJM footprint, investor classes participating in merchant generation investment include private equity funds, project developers, investment funds, underwriters/financiers, and merchant lenders. *See*, Bessemer and Shields (2015) *Resource Investment in the Golden Age of Energy Finance*, pps 10-11 http://www.isorto.org/Documents/Report/201505_IRCResourceInvestmentReport.pdf.

[56] It is thus not surprising to find exchange traded electricity futures contracts offered at liquid hubs in organized markets but not at points in non-market areas. Necessity being the mother of invention, where risks do not need to be managed, risk management tools are not created. *See, e.g.*, NYMEX Electricity Contracts offered for PJM and MISO points, online: http://www.cmegroup.com/trading/energy/#electricity; and Nodal Exchange "offer(ing) futures contracts for

In PJM, the following general classifications can be used to describe the types of hedging/risk management opportunities made available to the merchant investor:

- Market design that prices risk and creates instruments to manage risk
- Structured financing models that have evolved to facilitate capital formation specific to PJM's markets
- Secondary markets to hedge price risk

Despite PJM's markets and secondary supporting markets evolving tools to assist merchant investors in managing the risks associated with their generation investment, markets for certain important risks have not yet developed sufficiently and thus merchants face some key risks that cannot be managed effectively by the existing suite of hedging instruments. These deficiencies are significant and challenge the ability for PJM and merchants investing capital in PJM to realize fully the efficiency proposition that comes from allocating investment risk to merchants and away from consumers.

PJM Market Design

PJM's energy market prices electricity nodally. Where conditions (described by system operators as "constraints") prevent the transmission system from delivering the next most economic generation to particular load, PJM will dispatch more expensive generation (described as "out of merit order" dispatch) to serve load without creating flow that would additionally burden the constraint. When this happens, electricity prices will deviate in PJM with lower prices forming on one side of the constraint and higher prices on the other side. Locationally-priced electricity, typically by node as in PJM or by zone, is a basic characteristic of organized wholesale electricity markets. The locational aspect of energy market design has been borrowed, with some modification in PJM, to differentiate between the price of capacity in one location compared to another.

Price differentiation of capacity works to signal investment in regions that would benefit most from new investment. Higher pricing to favor investment in areas where that investment offers PJM, as system operator and reliability coordinator, a greater value, optimizes the value of the transmission system as a delivery network. Without explicit and transparent pricing of locational value, generation that is cost-comparable in all other respects can end up being more expensive once the costs of transmission expansion that could otherwise have been avoided or forestalled is taken into account. Imposing explicit costs on generators for needed network upgrades to enable the resource to interconnect as deliverable capacity, coupled with the market premiums generators can realize for locating new generation in capacity-constrained areas, offers a superior approach to getting generation in the right place at the right price. PJM's market design prices the risk of poorly located investment and places this risk on merchant investors to manage.

Structured Financing Models

In a recent study commissioned by the ISO/RTO Council[57], the authors reported strong availability of low-cost financing for new merchant facilities,[58] including Term Loan B financing. Project developers typically obtain debt financing through the

on-peak and off-peak power at commercially significant hubs, zones, and nodes in the following electric markets: ISO-NE, NYISO, PJM, MISO, ERCOT, CAISO and SPP.", on line at: http://www.nodalexchange.com/products-services/contracts/

[57] Bessemer and Shields (2015), note 55, *supra*.

[58] *Id.* at p. 13 ("Anecdotally, debt financing deals that were being done 3-4 years ago at LIBOR plus 700 -900 basis points (bps), are now being done at LIBOR plus 300-400 bps. Project debt-equity ratios have also been increasing from around 1:1, to closer to 2:1.").

Term Loan A, or senior term loan, market. Term Loan A financing comes with significant covenants, including (1) the requirement that almost all price exposure be hedged out five to seven years, which is a typical holding period of the asset for a developer and (2) substantial amortization, or repayment of principal, over the loan period. In contrast, Term Loan B financing has fewer restrictive covenants, with less rigorous hedging requirements but higher interest rates.[59] The study authors also reported strong investor interest in the PJM footprint.[60]

For project developers, uncertainty over electricity and fuel prices is the primary source of cash flow uncertainty, and lender requirements are a primary driver of hedging programs and financial derivative structures for new generating facilities.[61] For example, funding the construction of a merchant combined-cycle facility requires large sums on the order of $1,000/kW, financed in part by debt. Lenders, especially lenders of Term Loan A financing, often will require that the generating facility be hedged as long as possible, currently about five to seven, and the less effective the hedge, the more expensive the terms. Those hedges have three common structures: (1) physical tolling arrangements, (2) heat-rate call options and (3) revenue puts.

A natural gas generating facility is a physical conversion option, which gives the holder the option to convert natural gas to electricity when profitable – when the spark spread[62] exceeds the cost of generation, based on commodity prices and the facility's heat rate.[63] Liquid natural gas and electricity pricing hubs, like those in the PJM footprint, allow for physical tolling, which acts as a hedge for earnings and can facilitate financing for the construction of a natural-gas generating facility.

Under a typical tolling agreement, a marketer pays the owner of a generating facility a fee to "rent" the facility. The tolling fee typically has two parts: a fixed monthly capacity payment and a variable tolling charge for each megawatt-hour of electricity produced by the facility. The facility owner uses the fee to pay its lenders and provide an equity return. The fixed monthly capacity payment can be tied to the capital loan payments, eliminating default risk and facilitating debt financing. The marketer is responsible for the natural gas deliveries and electricity sales and generally takes the full commodity price risk in return for upside profit potential from forward and reverse tolling.[64]

A heat-rate call option entitles the holder of the option to purchase power at a strike price that is based on an indexed gas price multiplied by the generating facility's heat rate. Under a typical structure, the holder of the heat-rate call option captures the intrinsic value of a below-market heat rate and, in exchange, pays the facility owner a monthly capacity

[59] *Id.* at pp. 13-14.

[60] *Id.* at p. 17 ("PJM was seen as rebounding from a demand trough, and consequently seeing strong investment.").

[61] For merchant projects, sufficient cash flow is needed to cover debt service and, it is hoped, earn an equity return. Going forward, it is unclear whether merchants and lenders will have the tolerance to take on risky investments in large base-load generating facilities. At the same time, it is unclear to the extent that those large, risky investments will be needed. Technology breakthroughs – in energy storage, grid management, distributed solar and others – may dramatically transform base-load needs within the useful lives of generating facilities built today.

[62] Spark spread is the price difference in equivalent units between the market price of electricity and the market price of fuel at the same or nearby locations and for the same delivery period.

[63] Heat rate is a widely used measure of thermal efficiency that is used to compare natural gas and electric power quantities and prices in equivalent terms. Operating heat rate is a measure of the operating efficiency of a generating facility, expressed as the number of megawatt-hours of electricity expected from a given amount of natural gas in British thermal units (Btu). Economic heat rate, which typically is higher than the operating heat rate and is used to price transactions or establish contractual obligations, may include costs other than fuel costs, such as variable operating and maintenance costs, startup costs and ramping costs.

[64] A positive spark spread, based on the generating facility's economic heat rate, would indicate that it is more economical to burn natural gas to generate electricity than to purchase electricity from the grid, i.e., a forward toll. A negative spark spread would indicate that it is more economical to sell the natural gas in the spot market and purchase electricity from the grid, i.e., a reverse toll.

payment. As with a tolling arrangement, the monthly capacity payment can be tied to the capital loan payments, eliminating default risk and facilitating debt financing.

Based on recent interviews with merchant developers, revenue put options (or simply revenue puts) have emerged as the prevalent hedge structure for recent greenfield projects. Revenue puts establish a revenue floor for a generating facility that helps to stabilize earnings and ensure debt coverage. One developer characterized a revenue put as "debt market demand for debt service coverage protection," whereby, at financial close, the developer pays the revenue put provider to ensure that debt service will be met for the duration of the hedge.[65] For example, for an 800 MW plant with a total development cost of approximately $850 million, the developer will pay approximately $30 million-$40 million to a financial entity for a revenue put. Under the revenue put, the financial entity will ensure the debt holders that their debt will be serviced for the term of the hedge, currently about five to seven years. In all three of the above hedge structures, Financial Transmission Rights (FTRs) and over-the-counter basis swaps can reduce the risk of price differentials between a generating facility node and a liquid pricing hub.[66]

Secondary Markets

Moreover, those making investments in generation in PJM can turn to instruments made available in secondary markets to manage these risks. Certain of these markets offer generic hedging instruments that can be used to manage fuel price risk. Other markets offer instruments specifically designed to PJM's markets and allow parties the opportunity to hedge electricity risks and to manage these risks using a variety of means: FTR markets, bilateral trades financially settled, physical trades and cleared trades on NYMEX,[67] ICE,[68] Nodal Exchange[69] or other platforms. In general, organized electricity market regions like PJM, with liquid pricing hubs and a wide variety of financial instruments on multiple platforms, allow for clean and efficient hedges that facilitate project lending and capital investment.

Deficiencies

Lenders and merchant generation investors have developed customized financing structures to reflect the logic of PJM's market design in regards to its market prices, its allocation of risk and its evolution of tools designed to manage that risk. These structures additionally have accessed instruments offered in related secondary markets to help manage risks faced by investors in and lenders to merchant generation. While these arrangements have succeeded in forming capital to support investment in merchant generation in PJM, this success has occurred despite a potential glaring deficiency – the lack of a forward hedging instrument to lay off capacity and energy price risk over the long term.

Financing capital-intensive, long-lived merchant generation requires investors to assume natural gas price risks that can be effectively managed through exchange and bilateral markets only for perhaps five to seven years into the future. Hedging the price risk of the output – capacity and energy – poses an even bigger challenge for the merchant generator. PJM's capacity market is described as a forward market. Auctions for capacity occur three years prior to the delivery year.

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[65] Confidential interview on December 28, 2015.

[66] For example, the PJM Western Hub for electricity or the TETCO-M3 hub for natural gas.

[67] In 2003, NYMEX began offering financially-settled electricity futures with final settlement on real-time PJM Western Hub prices. These NYMEX futures contracts were the first with ISO/RTO-price final settlement. The PJM Western Hub now may be the most liquid electricity futures market in the world with trade multiples of over 4.7 in 2013. *See* Bessemer and Shields at p. 25.

[68] Intercontinental Exchange, or "ICE," is a major execution venue for over-the-counter trading in prompt and day-ahead markets for North American power.

[69] Nodal Exchange offers on-peak and off-peak day-ahead and real time contracts settled at LMP for monthly terms with expiries of up to a forward 68 months, at commercially significant hubs, zones and nodes in organized electric markets including the PJM markets. Nodal Exchange offers contracts on a wider set of locations than NYMEX and ICE and provides price signals at each nodal location. Nodal Exchange also offers "energy plus congestion" futures contracts for basis risk management.

But, PJM's capacity auctions provide only year-by-year certainty – as opposed to fixing price certainty over a strip of years. It was anticipated that price variability in PJM's auctions would spur buyers (load) and sellers (generation) to come together bilaterally in secondary markets to contract for the purchase and sale of capacity at a fixed price over a longer term. Evidence suggests that buyers and sellers are hedging their respective capacity price risks through bilateral contract in reasonably small volumes. Indeed, it appears buyers and sellers of capacity remain largely exposed to spot price outcomes.

Several factors may explain the reluctance to fix prices bilaterally. First, PJM's capacity market is relatively young, and it has required changes that have made it difficult to predict future prices based on historic outcomes, noting further that historic outcomes have demonstrated significant volatility. Second, retail choice regimes in several PJM states deter competitive retail providers from long-term wholesale contracting because end-use customers under such regimes typically are committed to six-month or one-year contracts with their suppliers. Third is the mandatory nature of PJM's capacity market, whereby all capacity must be transacted through the three-year forward auction or in any one of three incremental auctions before the start of the delivery year. However, perhaps the biggest and most obvious explanation is that the bid-ask spread, the difference between what buyers are willing to pay and what suppliers are willing to receive, for bilateral contracts is simply too large a gap to overcome.[70]

Conclusion: Findings Regarding Resource Entry in Markets

Having examined the goal of appropriate resource entry from several different vantages, the data show that markets are fulfilling their objective of motivating appropriate resource entry into the overall generation portfolio, and doing so in a cost-effective manner for the consumer. The results show:

- PJM offers a neutral, transparent proving ground for any project or technology to demonstrate its value based on its merits. High-capital, high-risk projects do not find footing, while lower-capital, lower-risk projects can flourish (if appropriate) without being impeded by a closed regulatory construct.
- PJM and regulatory regimes both are bringing new combined-cycle entry online at comparable costs (leaving aside the cost of risk).
- Once risk is examined, financial models show that, while the actual returns are appropriate for merchant generation given risk, the returns for regulated generation companies are notably higher than the models would predict given the lower risks they face.
- The abundance of merchant projects coming online in PJM indicates that the market is providing adequate returns to attract capital.
- Discrepancies in risk-adjusted returns between merchant and regulated investments may reflect regulators mispricing risk; and/or may result from capital competing for projects through use of both efficient financing structures and risk-management tools that serve to lower the cost of risk and returns.
- The PJM markets could see further cost efficiency from merchant entry if longer-dated risk management instruments were available.

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[70] See Pfeifenberger, Johannes, Newll, Samuel, Spees, Katheleen, Hajos, Attila, and Madjarov, Kamen ("The Brattle Group"), Second Performance Assessment of PJM's Reliability Pricing Model Market Results 2007/08 through 2014/15, prepared for PJM Interconnection, LLC, August 26, 2011. Online at http://www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM's_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133. The discussion on long-term contracting starts at p. 57 of the report. The authors note, "Suppliers of existing capacity are unwilling to enter long-term contracts at low current prices because they expect prices will rise. At the same time, buyers are unwilling to pay higher prices or even the cost of new generation when there are less expensive options currently available in the market." At p. 58.

Resource Exit: An Empirical Examination in Regulated and Market Environments

To test the theoretical hypotheses described earlier in this paper associated with resource exit, PJM examined the retirement of coal plants in PJM as compared to retirements in two different types of areas:

- areas of the country where organized markets do not operate
- in these same areas, but also including areas where organized markets optimize a given fleet of generating resources but rely largely on state regulation to dictate the entry and exit of these resources

The empirical data needed to contrast decision outcomes in markets and regulated constructs requires comparing generation units having similar attributes but located in different environments (market or regulated) with each facing the same type of investment decisions. With only 20 years of competitive wholesale market experience to work with, such cases are relatively few; however, changes in environmental policies present one such opportunity.

Mercury and Air Toxics Standards: A Recent Natural Experiment to Examine Capital Investment Decisions

In 2011 the U.S. Environmental Protection Agency issued the Mercury and Air Toxics Standards (MATS) rule mandating compliance by no later than April 2016. MATS is a command-and-control type program that requires coal and oil-fired generation sources to meet emissions-rate standards for hazardous air pollutants.[71] All affected coal and oil resources, regardless of location and operating paradigm (market or regulated), must comply with MATS. Consequently, given the nature of the rule, owners of effectively all noncompliant generators must choose to make capital investments or retire the resource.

The MATS rule differs from other recent environmental policies in that compliance requires more capital investment versus increased expenses or reduced operations. MATS is unique in that it forces a retirement if the capital investment is not made.

Moreover, because MATS was issued four years after the implementation of the PJM Reliability Pricing Model Capacity Market, it provides a natural experiment to examine how investment and capital allocation decisions differ between regulated and competitive market paradigms with respect to investment or retirement decisions.[72]

Empirical Test

In order to test for a difference in retirement trends between PJM and fully-regulated areas, data was collected on all coal generators in the continental United States and examined using an environmental upgrade cost model. The cost model provided a measure of the incremental cost each coal unit faced in order to continue to operate under the MATS rule. This cost figure was combined with data on exit/upgrade outcomes, and the results were analyzed to identify contrasting trends between PJM and regulated, non-PJM environments. Trends were identified using a logistic regression model. This

[71] Note that the studies looking at the Title IV SO_2 Trading Program and the NOx Budget Program must acknowledge a difference in the case of MATS, insofar as MATS is command-and-control regulation while the earlier rules created trading regimes with greater inherent flexibility. Additionally, the EPA has issued the Cross State Air Pollution Rule (CSAPR), which is a stricter extension of the EPA's Clean Air Interstate Rule for SO_2 and NOx emissions, and the Regional Haze Rule. Many compliance options for CSAPR and the Regional Haze Rule are complimentary to MATS compliance, and this paper does not attempt to control for them in the case study.

[72] The purpose of using MATS as a case study should not be taken as a re-examination of the MATS rule that PJM published in 2011 *See* PJM Interconnection, LLC, " Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants" August 26, 2011. ("PJM MATS Analysis")

statistical technique is a method for comparing the relationship between different inputs and outcomes and can help provide a mathematical answer to questions such as "Holding all else equal, is a generator more or less likely to retire in PJM compared to other areas?"

Method

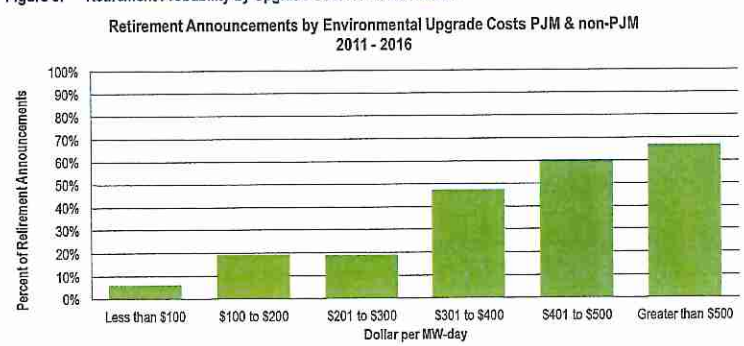
To determine the capital investment required to comply with MATS, PJM followed the methodology it used in its 2011 study on MATS[73]. This method uses a model from Sargent and Lundy to estimate the technology and costs required for compliance according to coal unit characteristics such as emission rate, nameplate capacity and coal type. With data on the cost of coal pollution control technologies from EPA at the time MATS was issued in 2011, the total retrofit cost needed to comply with MATS can be determined.

In order to conduct a robust examination of the data, different definitions of "regulated area" were examined. Appendix B to this report thoroughly describes the methodology, these definitions and the results of the analysis. This paper will discuss the results at a very high level and, for that purpose, will characterize the results of all the different variations. But, when a specific statistic or graphic is discussed, it will refer to PJM (defined by states that are largely within the PJM footprint) as compared to regulated states (defined as a variety of non-PJM states throughout the country that use integrated resource planning rather than a capacity market construct to handle portfolio planning, some of which are within ISO/RTOs that do not use robust capacity markets).

Validation of the Model

Once the model was created, PJM examined the model to verify that it performed as expected. For example, an observer would expect that the older a generator was, the more likely it would be to retire, all else equal. As expected, the model does show that a generator is more likely to retire if it is older, has a lower capacity factor and faces substantial capital investment costs for environmental upgrades (see Figure 5 below).

Figure 5. Retirement Probability by Upgrade Cost for all Generators



[73] "Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants", (2011)

Models of this type often are used to assess the difference in probability of an event as related to another factor (such as age). However, the results also are useful in the absolute. The model shows that the probability of retirement for a mathematically average generator is very low. The probability is slightly lower in PJM, and marginally higher in regulated, non-PJM environments.

Table 8. Predicted Probability of Retirement

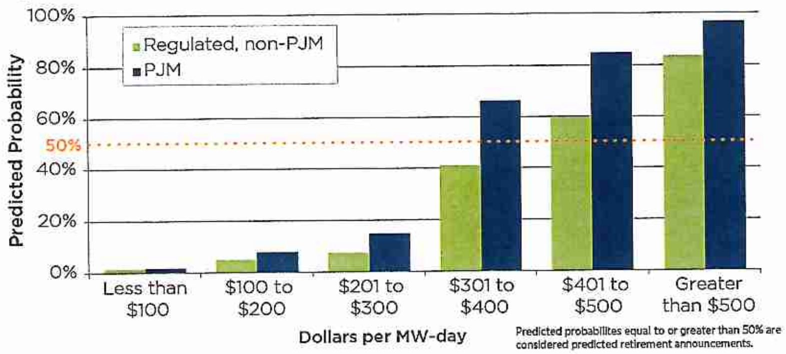
	Predicted Probability of Retirement
All Generators Studied	4.7%
PJM	0.7%
Regulated areas	8.8%

Results

Overall the model shows that the probability of the mathematically average generator retiring in PJM is lower than in the regulated environment. Under some definitions of "regulated environment," the difference is statistically significant, and in other scenarios it is not. The conclusion is that the likelihood of a generator exiting is approximately the same in PJM as in the regulated environment.

This is not to say there are no differences at all. Certain scenarios do show notable differences in the likelihood of retirement. Figure 6 below shows the probability of retirement for generators facing different levels of environmental upgrade costs.

Figure 6. Predicted Probability of Retirement by Upgrade Cost

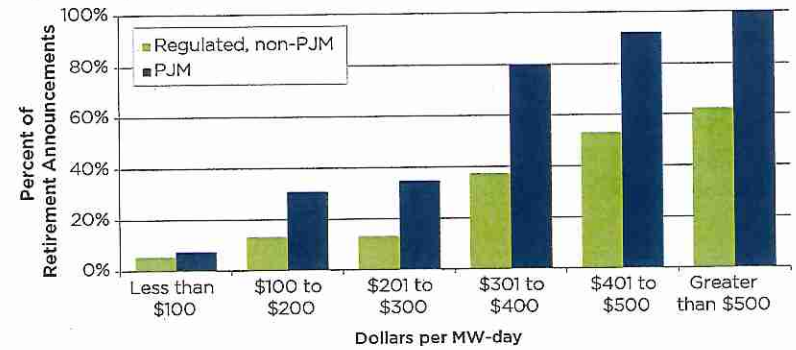


In both environments, as expected, generators facing significant upgrade costs have a higher probability of retirement. The probability is notably higher in the PJM environment. Given that the market is indifferent to the upgrade costs of a generator, this is a predictable outcome. Without greater revenues to support the generator, retirement would be a rational choice for the owner. This effect becomes more pronounced as the upgrade costs rise above the cost of new entry. In

regulated environments, where ratepayers support the upgrade (and where the utility is earning returns on capital investment), uneconomic generators are less likely to retire.

This prediction can be compared to the actual figures on announced retirements. The announced retirement figures show similar trends overall.

Figure 7. Comparison of Announced Retirements



Summary

The analysis of retirements due to MATS in PJM and in regulated areas shows no substantial difference in behavior: under both regimes, older, smaller units with relatively low capacity factors tend to retire. Likewise, generators located in both regulatory environments are more likely to retire as they face increasing upgrade costs. Under certain specifications of the model, units located within PJM tend to be more sensitive to increases in upgrade costs. This tendency becomes particularly pronounced when upgrade costs rise above the level of the cost of new entry.

For all generators, those units of average age, size, capacity factor and upgrade costs are not likely to retire. However, the average generator located within PJM is predicted to be even less likely to retire when compared to a regulated counterpart.

In general, the results show that a generator has approximately the same likelihood of retirement in PJM as in the regulated environment. The data presented here do not support the assertion that markets (compared to regulation) tend to force the retirement of generators that still have a remaining useful life.

Effectiveness of Markets in Managing the Resource Portfolio

This paper posed a significant question:

> *Can we rely on PJM's organized wholesale electricity market to efficiently and reliably manage the entry and exit of supply resources as external forces create tremendous uncertainty and potential industry transformation?*

The sheer scope of this question precludes a definitive answer within the context of a single paper or analysis. However, this paper has examined entry and exit in both market and regulated environments and set forth strong evidence showing the effectiveness of the PJM markets in managing the entry and exit of resources in the portfolio.

Regarding entry, the findings here reflect the conclusions that the markets do well in attracting new entry at an efficient cost. Competitive forces work to lower costs and exclude technologies with inappropriately high costs. The markets are incenting new entry at competitive costs. In addition, the market environments create a paradigm in which risk is shouldered by and managed by the investor, rather than the customer. The analysis shows that the returns for merchant generation companies are appropriate given the levels of risk. Moreover, comparing risk-adjusted returns for investments in regulated environments suggests that PJM customers are realizing superior value from merchant plants supported solely by PJM market revenues.

Regarding exit, the regression model based on the MATS natural experiment shows that generator exit when facing similar investment requirements is roughly comparable in both environments. The PJM markets show no signs of inadequately compensating legacy units and forcing a premature retirement of economically viable generators.

Collectively, the analysis shows that the PJM markets are succeeding in efficiently and reliably managing entry and exit, even while adapting to changing circumstances. However this should not be taken to say that the PJM markets can continue to manage resource adequacy in a cost advantageous manner in the face of any potential change. Indeed, as addressed immediately below, regulator actions to advance other political and social interests can disrupt and even defeat altogether the advantages that organized markets can bring in managing resource entry and exit.

PART 2
Actions Taken to Further Environmental, Social and Political Interests Can Erode the Market Value Proposition

Organized Electricity Markets and Public Policy

Within PJM, resources including demand response compete on price or cost subject to reliability constraints so that the mix of resources and energy production should come from the least-cost set of resources. In this sense, the PJM markets are neutral with respect to age, technology, size and fuel type, provided resources meet performance requirement to ensure reliability.

As examined in Part 1, the PJM markets offer a more attractive environment than non-market regions for the interconnection and participation of innovative technologies. Nevertheless, from time-to-time policymakers contend that organized markets are not integrating new technologies quickly enough or are not rewarding existing technologies sufficiently for their attributes. These attributes are often associated with technologies that advance environmental policies, or other objectives beyond the lowest-cost, reliable source of electricity.

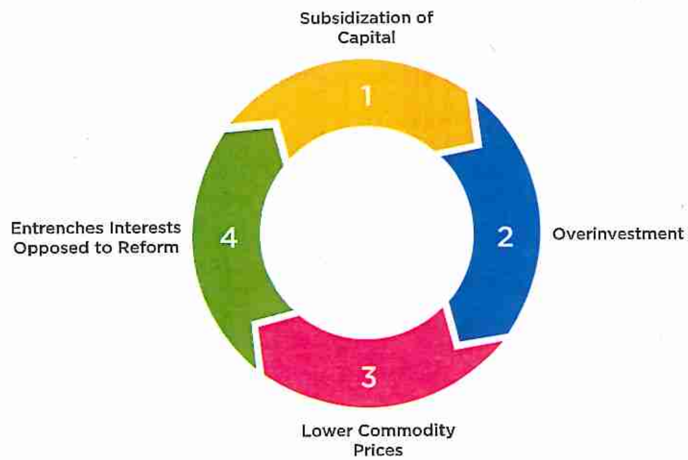
Policymakers may seek to promote or protect interests to which PJM's organized electricity markets are agnostic, including economic development, jobs, local tax base and fuel diversity. Promoting or protecting interests beyond the goal of providing reliable electricity at least cost – whether those interests are environmental, social or political – may take the form of subsidies. However, subsidies and other preferences can harm – in both theory and practice – the efficient operation of organized electricity markets to a degree that could threaten the mission of retaining only the most efficient resources needed for reliable operations and attracting new investment when economically warranted.

Explicit subsidies[74] take various forms in the electricity industry.

State & Local Government	State Public Utility Regulation	Federal Government	Federal Public Utility Regulation
Tax abatements	Net metering	Production tax credits	Full locational marginal price compensation for DR
Economic development grants	Feed-in tariffs	Tax credits	Reliability Must Run (potentially)
Tax Exempt Financing (Municipal)	Out-of-market payments State directed contracts	DOE Loan guarantees	Reference Power & Federal Power Marketing Agencies
	Stranded cost recovery	Funded research & development	

[74] Subsidies can be viewed as a two-sided coin: explicit subsidies for politically-favored resources and implicit subsidies that excuse or fail to price external or "public" costs created by resources. "(D)efining a subsidy to include all government interventions leaves out an important category: It 'does not include the externalities associated with electricity generation'." Moot, Subsidies, *Climate Change & The FERC*, Energy L. Jour. Vol. 35, No. 2, p. 349, quoting Kitson, et al., *Subsidies and External Costs In Electric Power Generation: A Comparative Review of Estimates*, 6 Int'l Inst. for Sustainable Dev. (2011). The table above touches only generally and superficially the panorama of subsidies affecting the electricity industry. Last year, the U.S. Energy Information Administration released a nearly 70-page report detailing just direct federal subsidies affecting electricity production. *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013*, (March 2015), online at: https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

In the electric industry, explicit subsidies effectively reduce the cost of capital to develop, construct or retrofit generating facilities that otherwise would be considered risky or too expensive and thereby not competitive but that are preferred because of other desired attributes as discussed above. This "capital bias" may lead to an overinvestment in generation resources with the resulting oversupply exerting downward pressure on commodity prices and reducing the financial viability of otherwise cost-effective resources. Lower prices and overinvestment sustained by subsidies may create entrenched and concentrated interests from both consumers and producers. Political interests similarly may be invested in campaigns to protect low prices or prevent the displacement of embedded capital and the resultant social and human costs, such as job losses or a diminished tax base. These interests, once entrenched, will naturally tend to resist policies removing their subsidies, and this contributes to an on-going cycle of subsidization.



Social, environmental and political interests typically justifying incentives and subsidies do not reflect competitive market principles because incentives and subsidies can create an uneven playing field among competitors and weaken the value of price signals. Those interests (e.g., jobs in local communities, industry to support tax base, the environmental advantages of renewable generation) may represent valid public policy objectives. However, organized electricity markets will not naturally advance those objectives except coincidentally to the extent they accompany the objective of least-cost, reliable electricity. Indeed, even objectives that may be considered elements of good energy policy, such as having a diverse generation portfolio or highly secure and resilient resources, will only result to the extent that organized markets ascribe value to, and pay for, those attributes. So, given the foregoing, can generation owners and local lawmakers fairly claim that PJM's markets are flawed because revenues are insufficient to cover the going-forward costs of certain legacy assets having desirable attributes? The question requires further examination.

Generally, an independent observer of a market would perceive a naturally arising commercial environment where the "invisible hand" is trusted to produce efficient price outcomes. When firms fail and invested capital is lost, the observer usually would not blame the market. To the contrary, the observer likely would view the market as pricing out inefficient resources or poorly considered or timed investments. However, organized electricity markets are less organic than most

commercial environments. They are highly designed, where price formation depends not only on the forces of supply and demand but also on a "visible hand" forging and implementing extensive rules and complex market clearing models and optimization algorithms.

Given the complex design features of organized electricity markets, it is fair to ask whether a generating facility struggling to earn sufficient revenue is coping with a valid price signal that indicates it should retire or whether instead it is impacted by a market design deficiency that could lead to premature retirement.[75] Getting prices "correct" is important especially considering that in PJM (as is true for certain other market operators) market design has been entrusted with the critical mission of ensuring adequate supply to maintain reliability. Moreover, broad economic and social harm beyond the energy markets could occur if inaccurate prices in organized electricity markets result in a suboptimal resource portfolio. Nevertheless, the simple fact that a generating facility cannot earn sufficient market revenue to cover its going-forward costs does not reasonably lead to the conclusion that wholesale markets are flawed. More likely, it demonstrates that the generating facility is uneconomic.[76]

Recently, when low market revenues have jeopardized the continuing viability of a generating facility, some have charged the market with harming important local interests, noting that asset retirement will cost jobs and deprive localities of property tax revenue.[77] These dislocations indeed are real and require difficult adjustments. Accordingly, wholesale market administrators must continually ensure that the returns provided by the organized electricity markets are "correct" and that legacy assets do not face inefficient, premature retirements.[78] If lawmakers, regulators or legacy asset owners believe the market suffers from a flawed design that suppresses prices or incompletely values certain resources, they will feel pressured or obligated to advocate for out-of-market subsidies intended to attract or retain resources they believe should be better compensated.

A generation resource that is state-subsidized through an out-of-market contract still participates in PJM's capacity market.[79] Given the comprehensive structure of the capacity market design, participation by subsidized resources will degrade price signals and potentially undermine the reliability objectives of the capacity market. Therefore, PJM has established the minimum offer price rule (MOPR) to mitigate potential harm to the capacity market from planned (new)

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[75] Such "deficiencies" cannot be presumed to always suppress prices. In fact, various PJM stakeholders regularly argue that market design flaws contribute to inflated prices.

[76] In comments to the U.S. Environmental Protection Agency (EPA), the Public Utilities Commission of Ohio (PUCO) described the long-term prices signals resulting from PJM's capacity market as designed "to allow for the continued maintenance of *all* existing generation facilities. . .", *EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Comments of PUCO, p. 5 Docket No. EPA-HQ-OAR-2013-0602, (December 1, 2014) (emphasis added). The PUCO's characterization of the PJM market omits the important qualifier that an existing generation facility should remain viable only to the extent it remains economic.

[77] *See The New York Times*, "Indian Point Owner to Close Nuclear Plant Upstate, Angering Governor," November 3, 2015 (discussing Entergy's decision to close the Fitzpatrick nuclear facility and reporting the impending loss of 600 high-paying jobs at a facility that pays half the property taxes collected by a local school district).

[78] The PUCO recently considered this assertion in granting a request by FirstEnergy, which owns certain legacy generating facilities that are struggling to earn revenues in the PJM markets sufficient to cover their going forward costs. FirstEnergy seeks a contractual stream of revenues sourced from ratepayers to "prevent plants from retiring before it is economic to do so." Deposition Testimony of Larry Makovich, PUCO, Case No-14-1297-EL-SSO, p. 3 line 5.

[79] A seller has little choice but to offer a state-subsidized generation resource into the PJM capacity market because market participation (and clearing) is required for the resource to be recognized as capacity towards PJM's resource adequacy requirement. Otherwise, if the resource is not credited as capacity, the load-serving entity will pay once for capacity under the out-of-market contract and again by operation of the PJM capacity market because PJM still must procure sufficient resources in the capacity market to meet system needs. Figures 8 and 9 below illustrate this point.

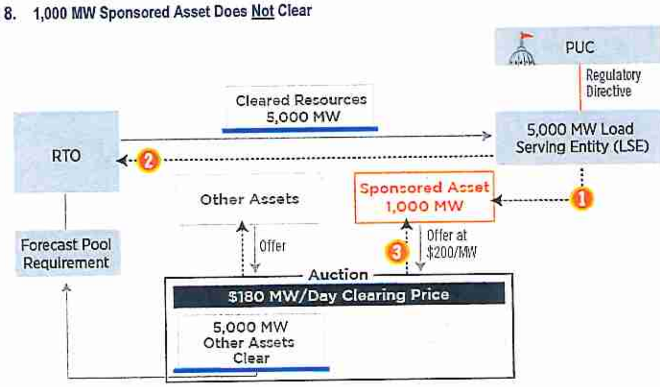
resources that received supplemental, out-of-market revenues.[80] The example below explains the need for mitigation rules.

An Example of the Need for Mitigation

Illustrated below is a simplified system showing a single load serving entity that is obligated to procure 5,000 MW of capacity to cover its load and reserves. The state public utility commission directs this LSE to enter into a contract for differences with the developer-owner of a new generating station (the "Sponsored Asset"); the LSE will pay the developer $200/MW-day minus any revenues the developer receives from clearing the ISO/RTO capacity market. The 1,000 MW Sponsored Asset will compete with both incumbent generation and potential new entry ("Other Assets") whose total installed capacity exceeds the 5,000 MW, which the RTO must procure to meet the LSE's load and reserve requirements. On the one hand, the developer is indifferent to whether its asset clears the auction because its contract guarantees it will receive $200/MW-day from the LSE regardless of the auction outcome; the LSE, on the other hand, is significantly interested in having the Sponsored Asset clear in order to reduce its contractual payments to the developer.

In Figure 8 below, the Sponsored Asset is offered into the auction at $200/MW-day. It does not clear the auction because the auction settles at $180/MW-day. Accordingly, the ISO/RTO charges the LSE for 5,000 MW at the auction price of $180/MW-day. Additionally, the LSE is contractually obligated to pay the asset owner $200/MW-day for the 1,000 MW that did not clear. In this case, the LSE pays a total of $1,100,000 for capacity procured to meet its load and reserves.

Figure 8. 1,000 MW Sponsored Asset Does Not Clear

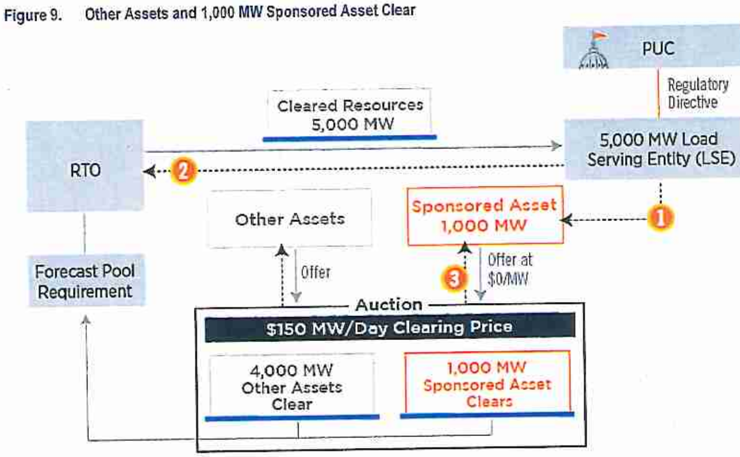


1 LSE pays Sponsored Asset under PPA	$200,000
2 LSE pays for auction procured MWs	$900,000
3 Sponsored Asset receives from auction	$0
1 + 2 LSE's total payment	$1,100,000
1 + 3 Sponsored Asset's total revenues	$200,000

[80] While all resources that clear a capacity auction will receive the single clearing price, the load serving entity that is party to the contract for differences is highly incented to ensure the subsidized generation resource clears (in order to avoid being charged for redundant capacity) and thus may contractually direct the seller to offer the resource into the auction at $0/MW. PJM's MOPR prevents the seller of a new-entry resource from acting on this incentive by requiring that the seller offer the resource into the auction at a price reflecting the resource's actual costs to protect the integrity of the auction's price outcome from artificially low offers made possible by the subsidy.

In Figure 9 below, the 1,000 MW Sponsored Asset is offered at $0/MW-day and thus clears the auction. In so doing, it displaces 1,000 MW of Other Assets, and its $0/MW-day offer, which is below cost, suppresses the clearing price from $180/MW-day – had the auction cleared without the Sponsored Asset (see price in Figure 8) – to $150/MW-day. The asset owner receives $150/MW-day from the auction for its Sponsored Asset. The ISO/RTO charges the LSE for 5,000 MW at the auction price of $150/MW-day. Additionally, the LSE will be contractually obligated to pay the Sponsored Asset owner $50/MW-day (the difference between the contract price of $200/MW-day and the auction price of $150/MW-day) for the 1,000 MW that cleared, for a total of $800,000.

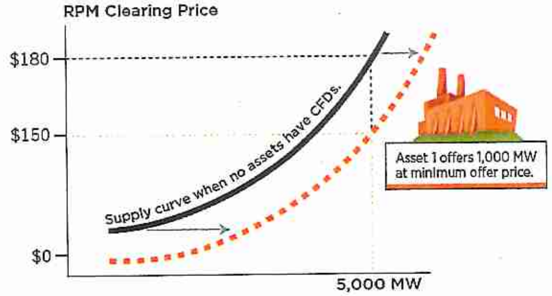
Figure 9. Other Assets and 1,000 MW Sponsored Asset Clear



1 LSE pays Sponsored Asset under PPA	$50,000
2 LSE pays for auction procured MWs	$750,000
3 Sponsored Asset receives from auction	$150,000
1 + 2 LSE's total payment	$800,000
1 + 3 Sponsored Asset's total revenues	$200,000

The difference between $180/MW-day and $150/MW-day, illustrated in Figure 10, shows the price degrading effect of the subsidy. Moreover, the LSE has succeeded in lowering its overall portfolio cost to procure capacity through the action of subsidizing the higher cost ($200/MW-day) resource and at the same time has cross-subsidized the rest of the load within the PJM footprint.

Figure 10. Illustrates Suppressed Price From Clearing Sponsored 1,000 MW Asset



Unintended Consequences of Out-of-Market Subsidies

Subsidies to generation – whether designed to suppress overall clearing prices or simply to spur new entry or retain investment in order to advance other "societal benefits" – means an "uneconomic" resource is introduced or retained in the PJM market with an expense that ripples through several areas of the markets.

Comparing Figure 8 and Figure 9 above illustrates how a buyer (an LSE) can be motivated to "overpay" a single generator with the blessing (or at the direction) of the regulator and in so doing (due to operation of the single-clearing-price function of PJM's capacity market) reduce its total costs incurred in procuring capacity to meet its load and reserve obligations. Revisiting the example above, offering the sponsored resource offered into the market in a manner that ensures it will clear (a $0/MW-day offer) will shift the supply curve to the right (Figure 10) and lower the LSE's total outlay from $900,000 (Figure 8) – the amount it would pay had it not arranged for the preferred asset – to $800,000 (Figure 9).

Given the relatively steep demand curves employed in capacity markets, even a modest level of subsidized supply can significantly impact clearing prices. The artificial increase in supply resulting from state action to subsidize incumbent generating facilities or to attract new entry (neither of which is supported by organized market prices) also can prevent new, more efficient entry. The simplified example above assumes that, if the state-sponsored resource does not clear (or, if it just does not exist), then 5,000 MW of incumbent resources would clear. However, the example does not consider a new entrant potentially offering into the auction at a price above the sponsored resource (*i.e.*, an offer exceeding $0/MW-day) and clearing, thus displacing an older, less efficient incumbent resource.

The harm caused by sponsored resource includes:

- artificial suppressing of clearing prices
- starving otherwise competitive incumbents from revenues they need to cover their costs of ongoing operation
- the potential "crowding out" of efficient new entry in favor of retaining less efficient, more costly to operate, and likely less environmentally desirable, older resources.

An economically inefficient resource clearing PJM's capacity market harms not just the price signal and resource mix of capacity, its participation in energy and ancillary services markets likely degrades those markets as well. Certainly, the participation of a resource that otherwise would not have been built or one that would have retired, necessarily will be at the expense of some other energy or ancillary services supplier. Quantifying the extent and consequence of this harm

depends on a multitude of complex interdependent variables, which this paper does not attempt to simulate or to demonstrate empirically. In the final analysis, the competitiveness of a resource in PJM will be determined by the revenues it earns from all PJM markets – energy, capacity and ancillary services. Thus, it is reasonable to assume that resources that must be propped up by external subsidy to be able to offer capacity into PJM's capacity market also will distort energy and ancillary service price outcomes. An older unit that should have exited, but for a subsidy, likely will displace a lower heat-rate, new unit that would have exerted the proper downward pressure on energy market prices. New entry brought in on the back of a subsidy likely will improperly exert this same pressure depriving incumbent resources of energy market revenues they should have earned.

In ISO/RTO regions with developed capacity markets, including PJM, the FERC has acknowledged the various harms described above and has accepted mitigation rules designed to scrutinize offers associated with state-sponsored resources. The objective of the mitigation rules accepted by the FERC, which in PJM require that an offer reflect the resource's actual costs, is to ensure that the offer is competitive, notwithstanding any out-of-market revenues derived from a contract for differences. This market impact is one reason why federal courts to date have invalidated, under constitutional doctrines of preemption, state subsidies that appear designed to target price outcomes in the capacity markets overseen by the FERC.[81] The U.S. Supreme Court recently affirmed these lower court decisions, albeit in a narrowly drawn opinion that will likely be interpreted as applying only to those subsidies that interfere directly (and probably by design) with a FERC-approved wholesale rate.[82]

PJM Markets and Interests That Can Be Argued in Terms of Electric Reliability

Some states in the PJM footprint are contemplating or engaging in actions that bear directly on investment in (or retention of) generating facilities, for the purpose of advancing state and local policy interests not recognized by the PJM markets. However, simply put, the purpose of PJM's markets is not to advance environmental interests, protect jobs in local communities, stem declining tax revenues in rural school districts or keep prices low to spur industrial economic activity. Rather, PJM's duty, as shared with its stakeholders and as overseen by the FERC, is to continually assess the performance of PJM's markets in producing accurate prices signals that encourage efficient resource investment and retirement decisions so as to maintain operational integrity and long-term reliability of the electric system.[83]

While some policy goals may be closely associated with PJM's core mission of providing least-cost reliable electricity, yet they are not reflected in market prices. For example, some commentators may argue that organized electricity markets should account for and accommodate environmental regulations and, in so doing, should provide financial incentives to sustain nuclear resources that could help meet policy objectives regarding carbon emissions.[84] While undoubtedly linked, environmental policy objectives are distinct from PJM's objectives; ultimately to the extent maximizing one policy objective

[81] These power purchase agreements were struck down on preemption grounds by the federal district and appellate courts. *See, N.J. Board of Public. Utilities. v. FERC*, 744 F.3d 74 (3d Cir. 2014) and *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467 (4thCir. 2014).

[82] *Hughes v. Talen Energy Marketing, LLC*, United States Supreme Court Docket Nos. 14-614 & 14-623, decided April 16, 2016.

[83] Perfection, with the benefit of hindsight, is not the standard. Investment decisions sometimes fail to incorporate relevant factors; and, in hindsight, markets sometimes misallocate capital. However, these "errors" arguably occur to a lesser extent in market environments like PJM's than in non-market environments, where monopolists and regulators handpick investment. Also, as repeatedly noted, in PJM risk is primarily borne by the investor, not by ratepayers.

[84] At least one commentator has opined that the economic threat to certain nuclear facilities shortsightedly removes from the climate policy equation perhaps the most efficient zero-emitting form of power generation. She blames organized electricity markets for exposing the economic vulnerability of those facilities while not valuing in some manner the public good of zero-emission generation. *See* Todd-Whitman, *Why Closing Nuclear Power Plants Is Short-Sighted*, *The Wall Street Journal* (Nov. 16, 2015) ("Making matters worse, poorly structured electricity markets are putting at risk other well-operated, proven nuclear-energy facilities in New York, Ohio, Illinois and other states. Once closed, these plants won't reopen. We must act now before it is too late.").

requires a trade-off with the other, that decision is one for lawmakers and regulators, not market administrators.[85] Having said that, from a pragmatic and an economic perspective, the more important question is not whether valid environmental interests are justifiably advanced by political entities, but whether the means used to advance these interests (including subsidies) are well designed in light of companion electricity market designs. There are ways to optimize competing interests, and, clearly, certain policy actions taken to promote one interest with consequence to the other can be less desirable and more harmful than alternate options. PJM's role is to inform the debate so that decision-makers can strike an optimal balance between environmental objectives and electric system reliability and the cost to the customer. Like maintaining jobs and the economic vitality of local communities, environmental interests associated with generating electricity, while clearly valid, are not properly advanced (nor countermanded)[86] by electricity market design. But electricity markets can accommodate transparent and well-designed programs that pursue particular environmental policy objectives.

Resource Diversity

Another interest currently debated in the industry is the public value of having a portfolio of generation resources with a diverse fuel supply. Because resource diversity can factor into system reliability, the question of whether PJM's markets should more explicitly value fuel diversity warrants closer examination. Some commentators have claimed that PJM's markets are flawed because PJM has resisted pursuing what may be described as a "two wrongs make a right" approach to market design, namely, imposing an "adder" to recompense legacy assets for the price-suppressing effects of subsidies given to certain types of politically-favored resources.[87] The concern over the future viability of legacy generation that is heavily dependent on energy market revenues[88] and resulting harm to grid reliability over the longer term should these units retire is not unique to PJM.[89] Still, PJM believes the goals of organized market design do not include counteracting existing subsidies by providing enhanced revenue opportunities to non-subsidized resources. However, the somewhat related question of whether PJM's markets should promote fuel diversity is more complex.

Having a diverse generation portfolio, thus avoiding overreliance on one fuel type, arguably is a system reliability interest. To the extent a resource provides services or attributes that further the reliability mission of the ISO/RTO, the market should compensate for those services and attributes. Today, with new generation dominated by natural gas facilities, two themes emerge. First, delivered natural gas is more of a "just-in-time" fuel compared to fuel for coal and nuclear facilities, which have on-site fuel storage.[90] This fuel attribute can challenge the availability of a natural gas resource relative to other fuel types, as was highlighted in eastern PJM during the "Polar Vortex" of January and February 2014. Second, fuel diversity can act as a hedge against future shocks. Therefore, an ISO/RTO may be imprudent to "go all in" on natural gas

[85] Retired Exelon Chief Executive John Rowe, when discussing the challenges facing certain facilities in the Exelon nuclear fleet, acknowledged this point when he opined that the "proper market-driven" answer is to shut down "uneconomic" nuclear facilities, and "if the real reason to keep them running is a public policy reason, then the public has to help bear the cost of doing that." Tomich, *Former Exelon CEO Rowe: Shutting down struggling nukes is 'the proper market-driven answer'*, E&E Publishing, LLC (July 27, 2015) (available at http://www.eenews.net/stories/1060022403).

[86] An illustration of what is meant here by "countermanding" is provided in footnote 87, *infra*, and the accompanying text.

[87] *See e.g.* Deposition Testimony of Larry Makovich, PUCO, Case No-14-1297-EL-SSO at 159, line 6 ("My testimony is that renewable mandates have suppressed the cash flows for base load power plants, and both these plants (Sammis and Davis-Besse) are base load power plants").

[88] Renewable resources typically produce energy at a zero or even, taking into account production tax credits, a negative marginal cost of energy. Their ability to act as price takers in PJM's energy markets, lowers energy clearing prices, and reduces the infra-marginal rents earn by capital intensive fossil and nuclear generation – rents that are necessary to cover on-going costs of operation and that contribute to capital costs.

[89] See, e.g., ISO-NE Revised Discussion Paper, *The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future*, pp. 5-6 (October 2015).

[90] The "real time" delivery challenge of electricity underscores the concern in relying on a "just-in-time" fuel supply.

because of unforeseen or underappreciated risks, such as a national ban on hydraulic fracturing or an accident that might change the supply and price dynamic for the fuel.

Regarding the first theme, it is true that certain fuel-type generating facilities might naturally provide a particular attribute valued by an ISO/RTO. Other factors being equal, a coal facility with coal in the yard offers greater dependability than a natural gas peaking facility with non-firm fuel supply. Likewise, a coal or nuclear facility will provide greater inertia to the bulk power system than a solar panel,[91] and a battery will provide faster and more controlled frequency response than a natural gas combined-cycle facility. However, from the perspective of the ISO/RTO, it is the attribute (e.g., dependability, inertia or frequency response) that is needed in the correct proportion, not necessarily a certain ratio of fuel type, even if that fuel type may be closely associated with the desired attribute.

PJM's Capacity Performance initiative addressed a shortcoming in PJM's capacity market by recognizing that the market, as designed, was not adequately valuing the reliability of a highly dependable and available fuel supply. The correction came not by directing a premium for a particular fuel type that could be stored on-site but by pricing the dependability attribute and allowing all resources, regardless of fuel type, the flexibility to determine how they may or may not provide the desired attribute. ISO-New England, another U.S. operator of a forward capacity market, voices a similar opinion in commenting on arguments often advanced to justify intervention to support legacy generation:

> *While policy initiatives like these may be desirable for other reasons, such approaches should not be needed to ensure reliability, or efficient market responses to an increased penetration of renewable resources. The current market design should ensure adequate resources to meet the reliability standards for which the markets are designed, as long as prices in the capacity market are appropriately formed. Appropriate price formation in the capacity market should ensure that the resulting resource mix appropriately complements the capabilities and limitations of the renewable resources entering the market.*[92]

Regarding the second theme, a diverse generation portfolio can provide a hedge against future shocks that could abruptly and dramatically change the relative appeal of one fuel over another. By their nature, large generating facilities cannot be made to appear on the system overnight; and, once shuttered, those resources may be gone for good. Given this reality, ISOs/RTOs may want to maintain a diverse set of resources, including resources that could be "uneconomic" in the short term, to hedge against future shocks.[93] While the merits of the fuel hedging argument can be debated, the issue can be fairly characterized as one of system reliability and thus arguably one that PJM should address in market design. However, due to the highly subjective decisions involved in determining the "correct" resource mix and the means and level of

[91] A greater penetration of renewable resources has prompted the question of whether ISOs/RTOs should compensate for inertia. *See* Alliance for Sustainable Energy, LLC, *Market Evolution: Wholesale Electricity Market Design for 21st Century Power Systems*, p. 23 (October, 2013) (available at http://www.nrel.gov/docs/fy14osti/57477.pdf) ("If some resources do provide the service (system inertia), and others do not, however, then some sort of compensation might be required.").

[92] *Infra*, note 89, *ISO NE Revised Discussion Report*, at p. 7.

[93] While this caution against overreliance on a single fuel is advanced today in the face of the prevailing "dash to gas," the most recent actual illustration of the risk can be found in the nuclear industry. The Fukishima Daiichi accident in 2011 resulted in dramatic policy, regulatory and public reaction that has materially increased safety compliance costs facing nuclear generation. These added costs have clearly factored into the closure of several nuclear facilities in the United States. In Japan, the future of dozens of nuclear facilities remains murky, with only one facility (Sendai) presently fully operational. In Germany, the Fukishima Daiichi accident accelerated plans to shutter existing nuclear facilities, advancing to 2022 a date by which the country has pledged to no longer rely on nuclear generation.

compensation to ensure that the desired mix is maintained, the matter lends itself to energy security policy determinations beyond the purview of an ISO/RTO.[94] Those are issues better addressed by legislators and regulators.

In conclusion, much of the fuel diversity criticism leveled at organized market design can be more appropriately recast as an issue of resource attributes needed to reliably and efficiently operate the system or dismissed as raising policy issues outside the proper scope of the ISO/RTO. What remains, namely the value of a diverse portfolio in hedging against future fuel shocks, (1) raises a "problem" that is speculative and not presently manifest in PJM and (2) would call for a solution that is subjective, complex and dependent on national or at least regional policy choices.

Diverse State Regulatory Environments in PJM: Subsidies Compared to Rate Regulation

The state contracting actions described as subsidies in PJM have been taken by states that legislatively elected to undertake retail competition that, in various forms, separated (or unbundled) retail utility operations (sales and distribution) from generation.[95] These states decided that incumbent supply and new generation investment would no longer be supported by rate base (retail customers) but would compete as merchant facilities alongside *other resources* in PJM's markets to serve load. It is important, however, to consider the nature of these *other resources*. PJM's markets are regional, spanning all or part of 13 states and the District of Columbia. Not all of these jurisdictions have taken steps to unbundle retail load from supply and several continue to regulate traditional vertically integrated electric utilities whose incumbent and new build generation is supported by the utilities' captive retail customers. Thus, the *other resources* against which a merchant facility competes in PJM's regional markets include other merchant facilities *and* facilities whose investment is supported by traditional rate base regulation.

Parties on both sides of the subsidy controversies point out that resources receiving out-of-market revenues through a state-mandated contract are placed in no different a position than resources developed and put into retail rate base by a vertically integrated electric utility pursuant to a state's traditional cost-of-service regulatory regime. The observation is valid up to a point. Whether legally significant distinctions exist to warrant treating each circumstance differently is a question the courts likely will decide. However, important practical differences bear on the competitiveness of organized wholesale electricity markets.

First, states that have elected to unbundle have decided (explicitly or otherwise) to rely on the wholesale markets administered by PJM to meet the resource adequacy needs of that state going forward. As PJM's markets are regional, this need will be meet by procuring the most economically efficient resources, whether those resources are located in that state or outside of (but deliverable to) that state. Actions these states take to subsidize in-state investment ignoring prices in PJM's markets, which signal either that no new generation is needed or that incumbent resources are no longer needed, will defeat the market's ability over the longer term to perform the job of assuring resource adequacy by suppressing the market price below its true economic level. In contrast, traditional rate-regulated states continue to assume the responsibility for meeting their state's resource adequacy objective and are not relying on PJM's markets to do so. While rate-based resources, depending on the terms of the regulatory arrangement, can be advantaged in comparison to

[94] Indeed, many would argue that PJM's fleet today is more diverse than when coal generation exceeded 50% of the resource mix. Freezing coal piles in the yard, barges locked in on a frozen Ohio or Mississippi river, and supply disruption due to a striking workforce are no longer the system operator's primary concerns to operational security.

[95] Examples include actions in New Jersey and Maryland to mandate that their retail utilities contract with new combined-cycle facilities. These actions, which were found by lower courts to impermissibly conflict with the federally-established PJM market, are subject to pending determination by the U.S. Supreme Court. Similarly, actions are being considered in Ohio and Illinois to support, for various policy reasons, incumbent generation facing closure due to the inability of these units to earn sufficient revenues from the PJM's markets.

merchant resources competing in PJM's markets, like many other similarly well established and programmatic subsidies (such as production and investment tax credits for renewable resources), the rate regulatory regime is a risk understood and accepted by the merchant at the time of its investment.[96] This contrasts distinctly with one-off, unit-specific regulatory intervention. These actions are unpredictable, largely because they cannot be reconciled with the otherwise explicit regulatory policy of that state to rely not on regulated utilities and their captive ratepayers but on markets and investors to assure adequacy.

Second, the history and evolution of cost-based ratemaking in many jurisdictions demonstrates an enlightened awareness of the shortcomings of that model, as described earlier in this paper. Recognizing these concerns, rate regulators in traditional cost-of-service jurisdictions do undertake competitive procurements and evaluations of "build versus buy" alternatives[97]; and there is reason to believe that such comparisons take place with greater rigor when state regulators have readily visible alternatives placed before them, such as provided by PJM's transparent and liquid markets. An asset that comes into the market based on an open, competitive solicitation does not present the same threat as an administratively subsidized resource whose costs are justified for political or social reasons that may not reflect the electricity policy objectives of the state public utility regulator, much less PJM. Indeed, even within the so-called deregulated retail jurisdictions in PJM, generation is contracted under multiyear procurements as an element of such state's competitive retail auctions.[98]

[96] Merchant investment has continued to add assets in PJM knowing that such investment will have to compete with new entry supported by "non-market" (i.e., rate regulated) constructs. See "New Generation in the PJM Capacity Market" (2016) by Monitoring Analytics, online at http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf. Notwithstanding this competitive challenge to market driven investments, merchant entry in PJM has significantly exceeded investment supported by rate regulation. Moreover, what is particularly noteworthy is that at least an equal weight of this merchant entry has come from private equity and private energy development funds, as opposed to the handful of publicly traded merchant generators or merchant affiliates of utility companies active in PJM. (Id. at p.9). Two conclusions can be reasonably drawn. First, having evaluated the overall, mix of varying state regulatory profiles in PJM, merchant investment is still prepared to enter PJM to compete alongside *some level* of assets supported by regulatory cost recovery. Changes in this mix, however, do appear to upset settled expectations of merchant investors and could become so unbalanced such that PJM in the future might no longer present an attractive opportunity for new merchant investment. Second, private equity theoretically deploys its capital agnostically, which is to say to investments that offer an attractive return regardless of their type. In contrast, publicly traded institutions that have defined themselves as "merchant electricity providers" have strategically committed to a business model where investment is made to develop and operate merchant generation. The robust participation in PJM by completely "voluntary" capital brought by private equity and private funds, suggests that PJM's markets remain competitively attractive relative to other generic investment opportunities.

[97] An example in PJM can be found in the 2013 amendments to the Virginia Electric Utility Regulation Act requiring an incumbent rate regulated utility to consider and evaluate alternative resource options, including those offered by third-party competitors. *See*, Title 56, *Public Service Companies*, Chapter 23. Virginia Electric Utility Regulation Act § 56-585.1.

[98] *See, e.g.*, Citation to Maryland and New Jersey SOS and BGS.GB

Conclusion

Understanding the advantages and disadvantages offered by organized electricity market design to manage the exit and entry of generation needed to maintain a reliable electric system is still evolving. This paper acknowledges that market tools face challenges relative to the traditional regulated model, particularly in accommodating environmental, social and political interests distinct from the singular mission to which markets are charged – delivering the most cost efficient resources needed to serve customers reliably. However, the paper also suggests the following key advantages:

- PJM is handling the exit of obsolete and uncompetitive generation in a comparable manner to regulated regimes.
- PJM is avoiding investment in highly-risky, highly capital-intense experimental utility-scale projects.
- PJM is successfully bringing online, the most cost-effective new generation at prices only somewhat higher than regulated regimes. But in so doing, PJM is placing on investors – and not ratepayers – the risk in these uncertain times that a particular investment made today is unexpectedly rendered uneconomic tomorrow.
- Moreover, once that risk is accounted for and valued in financial markets, it appears consumers are paying overly generous returns to regulated investment, compared to what they are paying merchant investors.

Realizing the "investment efficiency" advantages of PJM's markets can require policymakers to accept tough choices because efficient market outcomes may inflict harm to other policy objectives. Policymakers must weigh these trade-offs, but understand that pursuing individual actions that "defeat" efficient market outcomes will aggregate to a point they will altogether thwart effective operation of the market to the point it can no longer be relied upon to govern resource exit and entry and attract capital investment when needed.

While not the subject of this paper, once these trade-offs and consequences are appreciated, policies to protect or advance other social, economic or political interests can be implemented in such a way as to minimize or even eliminate the destructive harm to electricity market structures. Informed action of this sort will preserve the ability of PJM's markets to realize the "investment efficiencies" described in this paper, while also accommodating other social objectives.

RUNNERSTONE
INFORMATION IS POWER

RunnerStone, LLC

MEMORANDUM

Date: May 26th, 2016

To: Ohio Manufacturers' Association

From: RunnerStone, LLC

RE: Proposed Legislation on Ohio's Renewable Energy and Energy-Efficiency Standards

Three bills were recently introduced at the Ohio legislature which would affect Ohio's Renewable Energy Portfolio (RPS) and Energy-Efficiency Resource Standard (EERS). Senate Bill (SB) 320, SB 325, and HB 554.

SB 320, introduced by Sen. Bill Seitz, proposes consequential changes to Ohio's RPS and EERS, in addition to changes to Ohio's Special Improvement District (SID) and net metering laws. The bill also proposes limitations on the Ohio EPA's ability to devise federal Clean Power Plan compliance solutions.

Following is a summary of the proposed changes in the 100-page bill, specifically those that affect the renewable energy and energy-efficiency standards.

- Extended "freeze" – SB 221, passed in 2008, created annual benchmarks for energy efficiency and renewable energy procurement for Ohio's utilities. SB 310, passed in 2014, created a so-called "freeze" of these standards for the two years of 2015 and 2016. A cornerstone of SB 320 is to extend this freeze for three additional years. Moreover, additional requirements are not subject to annual benchmarks, but instead to 3-year tranches. In effect, the first compliance year for utilities would be six-years out in 2022.
  - Impact to manufacturers regarding renewable energy - Renewable energy costs have decreased dramatically in the past several years and continue to decline. It is unclear if this extended freeze will be a benefit or cost to manufacturers, as an analysis has not been undertaken.
  - Impact to manufacturers regarding energy-efficiency - Unlike with renewable energy, the SB 310 freeze did not result in halting utility energy-efficiency programs. Two utilities (AEP, DP&L) chose to voluntarily continue offering efficiency programs at pre-existing levels, Duke significantly reduced offerings, while FirstEnergy amended and suspended offering their programs. Efficiency program cost-effectiveness actually suffered with the utilities which reduced or suspended their program offerings. When properly operated and overseen, efficiency programs have been shown to produce net benefits to customers. Thus, whether this provision will produce a cost or benefit to manufacturers would depend on each utility's decision on whether or not to offer efficiency programs, and how well the program is operated and overseen.

- Expansion of the Efficiency "Opt Out" – SB 310 created an "opt-out" for above-primary electric users, such that these users can opt-out of participating in, and paying for, utility efficiency programs. SB 320 would expand this opt-out to all mercantile customers. A mercantile customer is defined as a facility which uses more than 700,000 kWh/year, or has multiple national accounts.
    - Impact to manufacturers - While an opt-out can provide important flexibility to manufacturers, if improperly applied it can also produce significant cost-shifting amongst ratepayers. Because a well-run energy-efficiency program can produce benefits to customers, reduction in the scale of programs could both increases costs of operating the programs to remaining customers, as well as increase costs of wholesale electricity. If a utility runs a cost-ineffective program, however, an opt-out provision could provide important relief.
- Project Eligibility – Several provisions of SB 320 create definition changes to what projects are eligible as renewable energy and energy efficiency.
    - Efficiency - Non-electric energy-efficiency would be eligible on a BTU basis.
    - Efficiency – Energy reduction related to water reduction. Presumably, this would count the energy reduction that occurs at a water treatment plant when water conservation opportunities are enacted.
    - Efficiency - Use of recycled glass would be eligible for efficiency incentives.
    - Renewable Energy – Combined Heat and Power (CHP) sytems installed after September 10th, 2012 would count as a renewable technology. CHP is already eligible as an energy-efficiency technology.
    - Renewable Energy – Electricity that is generated from combustion of solid waste, as defined in the Ohio Revised Code, would be eligible as a renewable energy technology provided that certain pollution controls are in place. According to the US DOE Energy Information Administration, there are currently no waste-to-energy generating plants in Ohio, but there are several in Indiana, Michigan, and Pennsylvania.

House Bill 554 was also recently introduced by Rep. Ron Amstutz. In contrast to SB 320, HB 554 is relatively straight-forward, with only a few provisions.

- Extended and permanent "freeze" – Similar to SB 320, the cornerstone of HB 554 is to extend the freeze, though permanently.
- Allowance of utilities to offer energy-efficiency programs - Similar to SB 320, HB 554 would allow the electric utilities to offer energy-efficiency programs voluntarily.
- Expansion of the Efficiency "Opt Out" – Similar to SB 320, HB 554 would expand the opt-out to all mercantile customers.

Senate Bill 325 was also recently introduced by Sen. Kris Jordan. SB 325 is essentially a repeal of the state's RPS and EERS. The difference between repeal and a "freeze" is that repeal would also affect future contracts for renewable energy credits (RECs) and solar RECs. While existing contracts would be honored until their end date, existing renewable energy projects would not be able to sell RECs/SRECs into an Ohio market.

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MEMORANDUM

To: OMA Energy Committee
From: Kim Bojko and Ryan O'Rourke, OMA Energy Counsel
Re: Energy Committee Report
Date: May 26, 2016

<u>Active Administrative Actions in which OMAEG is Involved</u>:

American Electric Power (AEP):

- PPA Rider Expansion Case (Case No. 14-1693-EL-RDR, et al.)
  - AEP, Staff, Sierra Club, Ohio Energy Group, Ohio Hospital Association, IGS and others filed a stipulation seeking PUCO approval to populate the PPA Rider with the costs associated with certain plants owned by AEP Generation Resources as well as the costs of AEP's entitlement to the OVEC output. IEU-Ohio agreed to not oppose.
  - The stipulation contains several other provisions unrelated to the PPA Rider, including: extension of the ESP III plan; expansion of the IRP program; and a proposal to develop wind and solar facilities.
  - The PUCO modified and approved the stipulation.
  - On rehearing, AEP stated that in light of the FERC decision it was going to only pursue recovery of the OVEC PPA.

- ESP Application (Case No. 13-2385-EL-SSO, et al.)
  - Order issued on February 25, 2015, wherein PUCO approved establishment of the PPA Rider, but AEP was not authorized to collect any PPA costs through the PPA Rider.
  - Entry on Rehearing subsequently issued – PUCO deferred ruling on applications for rehearing related to the PPA Rider.
  - Rehearing is pending.
  - AEP filed an application to extend the ESP through 2024.

- Fuel Adjustment Clause Cases (Case No. 11-5906-EL-FAC, et al.)
  - An audit estimated that AEP double recovered certain capacity-related costs in the amount of $120 million.
  - The PUCO reversed an earlier decision and held that parties have the right to receive copies of a draft audit report previously withheld from disclosure.
  - The draft shows that AEP may have double recovered by as much as $160 million.

Duke Energy Ohio (Duke):

- ESP Application (Case No. 14-841-EL-SSO, et al.)
    - Order issued on April 2, 2015, wherein PUCO approved establishment of the Price Stabilization Rider (PSR) regarding a PPA, but Duke was not authorized to collect any PPA costs through the PSR.
    - Several parties, including OMAEG, filed applications for rehearing of the PUCO's decision – the applications for rehearing are still pending.
- 2013/2014 EE/PDR Recovery (Case Nos.14-457-EL-RDR and 15-534-EL-RDR)
    - Duke and Staff filed a stipulation seeking to resolve the shared savings mechanisms relating to Duke's 2013 and 2014 programs.
    - OMAEG opposed the stipulation and the parties are awaiting a PUCO decision.
- Shared Savings Mechanism Extension Case (Case No. 14-1580-EL-RDR)
    - Duke sought PUCO approval of its request to extend the use of its shared savings incentive mechanism in 2016.
    - The parties are awaiting a PUCO decision.

FirstEnergy (FE):

- ESP IV Application (Case No. 14-1297-EL-SSO)
    - FE, Staff, Ohio Energy Group, OPAE, IGS, and others filed a stipulation seeking PUCO approval of FE's ESP IV Application together with authority to establish and populate the Retail Rate Stability Rider (Rider RRS) with the costs associated with certain plants owned by its affiliate, FirstEnergy Solutions.
    - The Stipulation also contains provisions addressing: grid modernization; energy efficiency; and a plan to transition to decoupled rates.
    - The PUCO modified and approved the stipulation.
    - On rehearing, FE stated that in light of the FERC decision it was no longer pursuing cost recovery of the affiliate PPA with FirstEnergy Solutions. However, FE is still seeking to recover costs through Rider RRS under a new proposal.

Dayton Power & Light (DP&L):

- Distribution Rate Increase (Case No. 15-1830-EL-AIR, et al.)
    - The PUCO set June 1, 2015 to May 30, 2016 as the test period and September 30, 2015 as the date certain.
    - Discovery is ongoing and parties are awaiting a forthcoming Staff report.
- Electric Security Plan (Case No. 16-395-EL-SSO, et al.)
    - DP&L is requesting to recover costs associated with several generating units that it is planning to transfer to an affiliate.
    - A Distribution Investment Rider and a Clean Energy Rider are also being sought.
    - Discovery is ongoing.

Statewide:

- Challenge to FirstEnergy Solutions RTO Expense Surcharge (14-1610-EL-CSS)
  - The PUCO decided that it has jurisdiction to hear the complaint filed by members of the opt-in group.
  - The PUCO issued an order preventing termination of service for the disputed charges.

- Net Metering Rules (Case No. 12-2050-EL-ORD)
  - OMAEG filed comments urging the PUCO to adopt rules that align the compensation schemes applicable to shopping and non-shopping customers.

Judicial Actions—Active Cases Presently on Appeal from the PUCO to the Supreme Court of Ohio

Duke Energy Ohio:

- Increase to Natural Gas Distribution Rates, Case No. 2014-328 (Appeal of Case No. 12-1685-EL-AIR, et al.)
  - OMA, OCC, Kroger, and Ohio Partners for Affordable Energy appealed a PUCO order that permitted recovery from ratepayers for environmental remediation costs associated with two former manufactured gas plant sites.
  - The matter is fully briefed and the parties await a date for oral argument.

Federal Actions

FERC Complaints:

- Complaints against AEP, FE, and their unregulated generating affiliates
  - RESA, EPSA, Dynegy, and a few others filed complaints seeking to rescind the waiver on affiliate power sales transactions granted to AEP, FE, and their unregulated generating affiliates.
  - OMAEG filed comments in support of the complaints.
  - FERC granted the complaints and held that no sales may be transacted under the affiliate PPAs until FERC determines that the contracts are just, reasonable, and free from affiliate abuse.

Court Cases:

- U.S. Supreme Court Case on Maryland's PPA Plan
    - On February 24, 2016, the Court heard oral arguments on Maryland's plan to boost in-state generating capacity by fixing the rate received by a generator for its sales into PJM.
    - 4th Circuit struck the plan down on preemption grounds, holding that it interfered with FERC's exclusive power to oversee the wholesale markets.
    - The Court found that Maryland's plan invaded FERC's exclusive jurisdiction to oversee the wholesale market.

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Summary of AEP's Application to Extend its Electric Security Plan

Background

On May 13, 2016, AEP filed an application and supporting testimony to amend its electric security plan (ESP) to include, among other things, an extension through May 2024. This amended ESP proposal is an outgrowth of AEP's PPA settlement case. A summary of provisions contained in the application is included below.

Early Termination

AEP states that its proposed amended ESP is dependent on its consent to the PUCO's decision and a favorable and timely outcome of the pending hearing in the PPA Settlement case. In the event either of these conditions do not occur, the ESP will terminate. Further, any decision, law, or order by a court, legislative authority, or administrative agency that adversely affects the viability of the PPA Rider may result in termination of the amended ESP by AEP.

Continuation and Modification of Riders

The following continuations and modifications have been proposed:

- Distribution Investment Rider (DIR) – AEP proposes to modify and continue the DIR, with additional annual caps to be established for the extended term of the proposed amended ESP.

- Interruptible Power Rider (Rider IRP) – AEP proposes to modify and continue the IRP through the extended term of the amended ESP. This extension will include current IRP tariff customers, as well as 250 MW of additional interruptible load, eligibility for which is limited to Signatory Parties and non-opposing parties to the PPA Settlement. 150 MWs of the additional interruptible load is reserved for new businesses locating in AEP's territory. Additionally, AEP proposes to increase the IRP credit beginning in June 2018.

- Basic Transmission Cost Rider (BTCR) and the Pilot Opt-In BTCR – AEP proposes to modify and continue the BTCR through the extended term of the proposed amended ESP. Additionally, AEP proposes a Pilot Opt-In BTCR provision, which would provide GS-3 and GS-4 customers with interval metering capability the opportunity to opt-in to a pilot mechanism based on the eligible customer's single annual transmission coincident peak demand.

- Economic Development Rider (Rider EDR) – AEP proposes to modify and continue Rider EDR through the extended term of the proposed amended ESP.

- gridSMART Rider – AEP proposes to continue the gridSMART program through further implementation of advanced technologies.

- Storm Damage Recovery Rider (SDR) – AEP proposes to continue the SDR mechanism through the extended term of the proposed amended ESP.

- Power Purchase Agreement Rider (OVEC-only PPA Rider) – AEP proposes to extend the PPA Rider through May 2024. Further, the new PPA Rider will include only the OVEC entitlement PPA.

- Alternative Energy Rider (AER) – AEP proposes to continue the bypassable AER, which recovers the costs of renewable energy credits.

- Energy Efficiency/Peak Demand Reduction (EE/PDR) Rider – AEP proposes to continue the EE/PDR Rider. Consistent with the PPA Settlement, 50% of the EE/PDR Rider's costs for transmission and sub-transmission voltage customers would be transferred to Rider EDR and 50% of the costs of the IRP would be transferred from the EE/PDR Rider to Rider EDR.

New Riders

AEP is proposing to add the following riders:

- Competitive Incentive Rider (CIR) –AEP proposes a pilot bypassable rider, the CIR, as an addition to the SSO non-shopping rate. The asserted purpose of the rider is to incentivize shopping. Revenues collected through the CIR will be refunded to all customers through the SSO Credit Rider (SSOCR).

- Automaker Credit Rider (ACR) – AEP proposes an ACR to support increased utilization or expansion of automaker facilities in AEP's service territory. The ACR will provide a credit for all consumption above the customer's baseline consumption, with total credits for all customers not exceeding $500,000 annually. Credits issued under the ACR will be recovered through Rider EDR.

- Submetering Rider – AEP proposes to recover contingent costs associated with submetering.

Procedural Schedule

AEP requests an evidentiary hearing to begin July 25, 2016, with a PUCO Opinion and Order by September 21, 2016.

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MEMORANDUM

TO: Ohio Manufacturers' Association Energy Group Members

FROM: Kimberly W. Bojko and Ryan P. O'Rourke, Carpenter Lipps & Leland LLP

DATE: April 19, 2016

SUBJECT: Summary of U.S. Supreme Court decision invalidating Maryland's plan to guarantee a capacity payment to a generator distinct from the PJM wholesale auction rate

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The U.S. Supreme Court recently upheld a lower court's decision, holding that a Maryland Public Service Commission (Maryland PSC) plan to boost in-state generating capacity with subsidies paid by ratepayers unlawfully intruded on the Federal Energy Regulatory Commission's (FERC) jurisdiction over wholesale rates. The Maryland PSC required the local utilities to enter into a 20-year purchase power agreement or contract for differences (PPA) with the generating company selected to construct a new power plant in Maryland. Under the PPA, the generating company sold its capacity into the PJM market. If PJM market revenues received by the generating company fell below the contractual rate, the utilities were then required to pay the generator the difference between the PJM clearing price and the contractual rate. In turn, the utilities passed these costs onto customers. If PJM market revenues exceeded the contractual rate, the generating company paid the utilities the difference between the contractual rate and the clearing price. In turn, the utilities passed these credits back to customers in the form of lower rates. In either event, the generator ultimately received the contractual rate set by the 20-year PPA, not the rate that cleared the PJM capacity auction.

The Court affirmed that FERC has the exclusive authority to set wholesale energy and capacity prices and oversee whether those rates and charges are just and reasonable. In the exercise of this authority, the Court observed that "FERC has approved the PJM capacity auction as the sole ratesetting mechanism for sales of capacity to PJM, and has deemed the clearing price per se just and reasonable." The problem with the Maryland PSC's plan, the Court explained, was that the PPA guaranteed the generator a rate distinct from the clearing price set in PJM's capacity auction. By departing from this ratesetting mechanism, the Maryland PSC impermissibly veered into "FERC's regulatory turf."

The Court rejected the Maryland PSC's argument that the plan was authorized because it was an attempt to spur new in-state generation, stating "States may not seek to achieve ends, however, legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates [.]" The Court also refuted the Maryland PSC's contention that the plan was indistinguishable from a traditional bilateral contract. Unlike a traditional bilateral contract, the generator sold its capacity into the PJM auction as opposed to selling its capacity directly to a utility.

The Court concluded by noting that its decision does not address the permissibility of State measures that encourage new generation through tax incentives, land grants, direct subsidies, state-constructed generation, or re-regulation. Those measures, however, must be "untethered to a generator's wholesale market participation."

The Court's decision bolsters OMAEG's position in the AEP and FirstEnergy PPA cases. Just like in the Maryland case, the PPAs in the AEP and FirstEnergy cases guarantee a rate that is distinct from the clearing price set in PJM's capacity auction. The PPAs at issue in the AEP and FirstEnergy cases guarantee a payment to the generators different from the clearing price set in the PJM auction. OMAEG has argued that this type of arrangement, just like in Maryland, impermissibly interferes with FERC's authority to oversee wholesale rates as the guaranteed revenue stream from customers will make the affiliate generating units agnostic to wholesale-market prices, distort wholesale-market price signals, and deter new entry from competitive generation suppliers.

To date, the PUCO has declined to address the federal preemption argument, reasoning that the issue is better suited to resolution by a court rather than an administrative agency. In the upcoming application for rehearing process, OMAEG will cite to the recent Supreme Court decision as grounds for invalidating AEP's and FirstEnergy's PPA mechanisms. Nonetheless, given the PUCO's previous evasion of the issue, the PUCO may continue to decline to address the issue and force parties to seek court resolution.

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April 28, 2016

Federal Energy Regulatory Commission Unanimously Decides that the Affiliate PPAs Proposed by AEP, FirstEnergy, and their Unregulated Generating Affiliates are Ineffective

In a unanimous decision, the Federal Energy Regulatory Commission (FERC) granted the complaints filed against AEP, FirstEnergy, and their unregulated generating affiliates (Respondents). FERC rescinded the waivers on affiliate power sales restrictions previously granted to Respondents and further held that "no sales may be made with respect to the Affiliate PPA[s] unless and until [FERC] approves the Affiliate PPA[s] under *Edgar* and *Allegheny*."

FERC agreed with the arguments asserted by OMAEG and others that circumstances have changed since the waivers were originally granted and further agreed that customers are captive because they have no ability to avoid the costs associated with the Affiliate PPAs by shopping with a competitive supplier. According to FERC, "retail choice protects customers from affiliate abuse only to the extent they have a choice to undertake generation costs. Where, as here, circumstances demonstrate that a retail customer has no choice but to pay the costs of an affiliate transaction, they effectively are captive with respect to the transaction." In response to arguments that the PUCO can protect customers, FERC noted that the PUCO's authority is limited to the retail sphere. FERC noted that only it has the exclusive power to regulate the wholesale sphere, which includes an evaluation of whether the Affiliates PPAs are just and reasonable.

Strong language about the transaction itself suggests that FirstEnergy and AEP will be facing an uphill battle in any review of the Affiliate PPAs in the next phase: "[FERC's] affiliate sales restrictions protect against captive customers of franchised public utilities cross-subsidizing market-regulated power sales affiliates. The Affiliate PPAs raise[] the potential for cross-subsidization from [the] Regulated Utilities' retail customers--who are captive in the sense that they cannot avoid the non-bypassable charge--to [their] Ohio Market Affiliates." FERC also stated that the Affiliate PPAs may affect other waivers that the Respondents have regarding corporate separation and affiliate interactions. The FERC required the Respondents to explain whether the Affiliate PPAs affect any other waivers that they currently possess.

FERC noted that OMAEG submitted a timely motion to intervene, thereby making it a party to the proceeding. FERC also noted the arguments of OMAEG multiple times throughout its order, and used these arguments to support its rationale to rescind the waivers previously granted to the Respondents.

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Summary of PUCO Order on AEP Ohio Purchase Power Agreement

The Public Utilities Commission of Ohio (PUCO) unanimously approved, with modifications, a settlement authorizing AEP to begin recovering costs through the Power Purchase Agreement (PPA) Rider for an eight-year term. The PPA Rider collects from retail customers on a nonbypassable basis the costs associated with several generating units owned by AEP's unregulated generating affiliate, AEPGR, as well as the costs related to AEP's contractual entitlement to the output from the Ohio Valley Electric Cooperative (OVEC).

The PPA Rider

- The PUCO based its decision to approve the PPA Rider on a projected net credit of $214 million over the next eight years.
- The PUCO limited customer bill increases for the first two years of the PPA Rider to 5% of the June 1, 2015 SSO rate on a customer-by-customer basis. The 5% cap, however, does not apply to the costs associated with any past or future distribution-related proceedings (e.g., distribution investment rider increases, straight fixed variable costs, grid modernization costs, storm rider costs, etc.) and the development of renewable projects (presumes costs for these projects will be passed onto customers).
- The PUCO provided that any revenue reductions resulting from the caps can be recovered in the next quarterly update after May 31, 2018 (this could cause a significant increase in customer bills in June 2018).
- The PUCO clarified that AEP cannot seek recovery of any portion of the $100 million credit commitments if they are actually applied by AEP.
- The PUCO removed the prohibition of refund language in the stipulation in the event the PPA Rider is invalidated on appeal, stating that it was a matter for the PUCO or the Court to decide. Importantly, the PUCO did not, however, state that refunds would be allowed in the event the PPA Rider is found to be unlawful.
- The PUCO clarified that AEP cannot seek recovery of any Capacity Performance penalties, but permitted AEP to retain any Capacity Performance bonus payments.
- The PUCO modified the settlement so that if any PPA unit experiences a forced outage exceeding 90 days, the PUCO may disallow the costs associated with the outage (but is not mandatory and allows the Staff to recommend otherwise).
- The PUCO rejected AEP's commitment to implement the PPA Rider initially based on a $4 million credit and authorized AEP to begin collecting the net effects of the OVEC PPA and Affiliate PPA beginning June 1, 2016.
- The PUCO rejected AEP's request to flow through the PPA Rider costs associated with AEPGR's obligations or entitlements to Buckeye Power's Cardinal Units 2 and 3;

however, the PUCO stated its decision was based on the current record and AEP could file a supplemental application to request that these additional costs be passed on to customers in the future.

- The PUCO provided that the liquidated damages provision does not apply if a court later declares the PPA or any PPA-related provision invalid. The PUCO also reserved the right to reevaluate or modify the PPA Rider, without triggering the liquidated damages provision, if PJM changes its rules to prohibit the PPA units from bidding into the PJM's auctions.
- The PUCO modified the settlement so that AEP cannot recover any conversion costs (i.e., co-firing, refueling, or repowering) and also clarified that no retirement costs are eligible for recovery.
- The PUCO disagreed that its oversight over the PPA Rider was illusory and stated that parties will have the right to intervene and participate in annual audits.

Other Settlement Provisions

- **Payments to Signatories**. The PUCO stated that monetary inducements to parties that add value to the stipulation as a package are ok. The PUCO disagreed that specific payments to OHA and OPAE were unduly favorable, but the PUCO required the filing of compliance reports to show that funding is being spent properly (and stated an audit may be ordered). The PUCO added that energy efficiency administrator payments are ok.
- **Transferring costs from EE/PDR Rider to EDR Rider.** The PUCO rejected a favorable settlement provision that allowed 50% of the EE/PDR Rider costs from transmission and sub-transmission voltage customers and 50% of the costs associated with the IRP credits to be transferred from the EE/PDR Rider to the EDR Rider upon approval of the Stipulation (rather, the PUCO stated that such request should be proposed in AEP's application to extend the ESP).
- **Future Filings**. The PUCO stated that it was not prejudging the outcomes of AEP's commitments that will be featured in future filings (promotion of economic development and retail competition, facilitate energy efficiency measures, reduce carbon emissions, deployment of renewable resources, and grid modernization); however, the PUCO stated that it found value for customers in AEP's commitments to raise these proposals in future proceedings.
- **Renewables.** The PUCO stated its support for the construction of new renewables in the state. AEP is encouraged to pursue bilateral contracting opportunities first. AEP should emphasize solar projects. To the extent bilateral contracting opportunities are not available, the PUCO will then entertain a cost recovery filing. AEP must show that a competitive process was used to source and determine the ownership of any project.
- **Smart Grid.** The PUCO noted the state's policy in promoting smart grid programs and advanced metering in the state and encouraged AEP to ensure that its grid modernization business plan engages customers, supports flexibility, and meets resource adequacy needs.

- **AEP's Headquarters.** The PUCO modified the settlement so that if AEP does not maintain its headquarters in Columbus, the PUCO may terminate the PPA Rider.
- **IRP Expansion.** The PUCO stated that any arguments concerning the merits of the IRP expansion or whether IRP customers may also be able to opt-out of the EE/PDR Rider are premature and should be raised in a future proceeding.
- **ESP v. MRO Test.** The PUCO disagreed that authorizing cost recovery through the PPA Rider resulted in AEP's ESP 3 being less favorable than an MRO. According to the PUCO, the PPA Rider will bring $37 million in additional benefits over the current ESP term.

FERC Matters

- The PUCO opined that its approval of the PPA Rider did not intrude on the powers of the Federal Energy Regulatory Commission (FERC). According to the PUCO, its approval of the PPA Rider rested solely on its retail-ratemaking authority.
- OMAEG and others argued that the PUCO could not approve the PPA Rider because it would interfere with FERC's authority to oversee the wholesale markets. The PUCO did not address this question, explaining that the question was better suited to judicial resolution.
- The PUCO stated its belief that retail customers are not captive customers because of retail choice; however, the PUCO did not address that customers cannot escape the charge created by the affiliate contract. Further, the PUCO stated that the PPA Rider will not restrict current shopping customers; however, the PUCO also found that the PPA Rider was a limitation on shopping in order to authorize it under the ESP statute. OMAEG and others are currently arguing at FERC that retail customers are captive because they cannot avoid the Affiliate PPA Rider by shopping with a supplier. The parties are awaiting a FERC decision.

Concurring Opinions

- **Commissioner Trombold.** She asserted that the settlement *will* result in grid modernization and more renewables. Commissioner Trombold also stated her "clear expectation" that the PPA Rider will result in a net credit over the next eight years.
- **Commissioner Haque.** He conceded that a consumer *charge* is likely in the first 2-3 years of the PPA Rider, which seems to be contradictory with the Order that projected a $37 million benefit accruing to customers for the next two years. He also implied that he may not have approved the PPA Rider standing alone, which perhaps suggests that the additional commitments to the settlement were necessary to secure his approval of the PPA Rider. He stated that Ohio is due to have "utility 2.0" conversations about grid modernization, but acknowledged the "stark reality" that these conversation never would have occurred without packaging the PPA Rider together with the other settlement provisions.

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Summary of PUCO Order on FirstEnergy Purchase Power Agreement and Electric Security Plan

On March 31, 2016, the Public Utilities PUCO of Ohio (PUCO) issued an Opinion and Order in FirstEnergy's application for an electric security plan (ESP). The PUCO determined that the Stipulated ESP IV was reasonable and should be adopted, with certain modifications. The information included below summarizes key provisions of the approved ESP IV, as well as modifications adopted by the PUCO. Several of these modifications were argued by OMAEG in their initial and reply briefs to the PUCO.

Rider RRS

- **Approval of a nonbypassable credit or charge.** The PUCO approved the Retail Rate Stability Rider (Rider RRS) as a nonbypassable credit or charge to customers. Through a proposed power purchase agreement between FirstEnergy and its affiliate, FirstEnergy Solutions (FES), FirstEnergy will purchase the capacity, energy and ancillary services output of FES' Plants and FES' OVEC entitlement. FirstEnergy will then sell the output of the Plants and the OVEC entitlement into the wholesale markets operated by PJM and net the revenues received from the PJM markets against the costs to be paid to the generator, crediting or charging the difference to all customers through Rider RRS.

- **Limit of Rider RRS.** PUCO modified the Stipulation to require FirstEnergy to implement a mechanism to ensure that for the period of June 1, 2016 through May 31, 2017 and June 1, 2017 through May 31, 2018, average customer bills do not increase as compared to the average customer bills for the period of June 1, 2015 through May 31, 2016. The PUCO states that this will ensure that "the average customer bill will see no total bill increase for two years." However, FirstEnergy is permitted to defer expenses for future recovery in an amount equal to the revenue reduction resulting from the period of June 1, 2017 through May 31, 2018. Further, costs recovered for smart grid deployment (presumes cost recovery), costs from renewable energy procurement (presumes cost recovery) and the Alternative Energy Rider (Rider AER), and impacts on riders resulting from credits to customers due to disallowances by the PUCO will be excluded from the mechanism.

- **FirstEnergy must file quarterly true-ups of Rider RRS.** PUCO modified the Stipulation to require FirstEnergy to file annual forecasted values subject to quarterly true-ups, reflecting actual values, rather than the annual true-ups proposed in the Stipulated ESP IV. Quarterly adjustments should be filed on or before March 1, June 1, September 1, and December 1 of each year. Notwithstanding the quarterly true-ups, Rider RRS is still subject to adjustment through the annual audit and reconciliation. The audit process will be carried out consistent with past practice.

- **<u>Cost Recovery.</u>** FirstEnergy is precluded from recovering plant retirement costs and capacity performance penalties through Rider RRS or recovering any credits provided to customers through Rider RRS in a future proceeding. The PUCO modified the Stipulation to clarify several points related to what costs could be recovered through Rider RRS. According to the Stipulated ESP IV, FirstEnergy will provide up to an aggregate $100 million in years five through eight of Rider RRS, in the event the revenues from the generation output do not exceed the costs in each year by a specified minimum credit amount. The Stipulation was modified to exclude the recovery of costs associated with any of these credits in a future PUCO proceeding. Further, the Stipulation was modified to exclude plant retirement costs and Capacity Performance penalties, but Capacity Performance bonuses will be retained by FirstEnergy. Finally, the PUCO reserves the right to prohibit recovery of any costs related to any unit for any period exceeding 90 days for any forced outage during the term of ESP IV (but not mandatory).

- **<u>The severability provision.</u>** The PUCO modified the severability provision to allow the PUCO to reserve the right to reevaluate and modify the Stipulation if there is change to PJM's tariffs or rules which prohibits the plants from being bid into PJM auctions.

- **<u>Term.</u>** The PUCO approved the eight-year term of the Stipulated ESP IV to begin June 1, 2016 and end May 31, 2024.

- **<u>Distribution Freeze.</u>** The PUCO approved the continuation of the base distribution rate freeze for an eight-year period beginning June 1, 2016 through May 31, 2024 with exceptions.

- **<u>Delivery Capital Rider (Rider DCR).</u>** The PUCO approved continuation and expansion of Rider DCR. FirstEnergy will continue to recover reasonable investments in plant in service associated with distribution, subtransmission, and general and intangible plant through Rider DCR. Further, the revenue caps for Rider DCR will increase annually to $30 million for the period June 1, 2016 through May 31, 2019; to $20 million for the period June 1, 2019 through May 31, 2022; and to $15 million for the period June 1, 2022 through May 31, 2024.

- **<u>Government Directives Rider (Rider GDR).</u>** The PUCO approved the Government Directives Rider (Rider GDR), which will initially be set at zero. FirstEnergy is permitted to recover unforeseen expenses related to government mandates imposed during the term of ESP IV through Rider GDR. The rider will be set initially at zero and FirstEnergy must file an application in a separate proceeding to recover any specific costs. The PUCO adopted the following <u>modifications</u> to Rider GDR: Rider GDR is limited to federal and state government mandates enacted after the filing date of the application, and generation or transmission related expenses may not be recovered under Rider GDR.

Other Provisions.

- **Shareholder Funding.** The PUCO approved shareholder funding to be provided by FirstEnergy to promote job retention, economic development, and low-income funding. FirstEnergy will provide $3 million per year in shareholder funding to promote job retention and economic development in the region. Specifically, FirstEnergy will provide $24 million in economic development funding, $19.1 million in low-income funding to the Citizens Coalition and OPAE, and $8 million in funding to the Customer Advisory Agency funding.

- **Automaker credit.** The PUCO approved continuation of the automaker credit. FirstEnergy will continue the automaker credit beginning June 1, 2016 through May 31, 2024.

- **Rider ELR and the Interruptible Credit Provisions.** The PUCO approved continuation and expansion of the Economic Load Response Program (Rider ELR) and the Interruptible Credit Provisions. FirstEnergy will continue to recover costs through Rider ELR for the eight-year term of the ESP. Further, Rider ELR will be expanded to include an additional 136,250 kW of curtailable load, which will be utilized by five new customers who have been eligible to take credit under Rider ELR but have historically be unable to do so. Moreover, ELR customers will be permitted to shop during the term of ESP IV and FirstEnergy will be limited to curtail these customers for emergency situations only. Participating customers receive an interruptible credit of $10 per kW per month per unit of curtailable load in exchange for participation in the program and subjecting their load to interruption.

- **Commercial High Load Factor Experimental Time-of-Use Rate.** The PUCO approved adoption of a Commercial High Load Factor Experimental Time-of-Use Rate proposal. FirstEnergy will deploy a Commercial High Load Factor (HLF) Experimental Time-of-Use rate proposal for commercial customers with headquarters located in Ohio having at least 30 facilities in the FirstEnergy combined service territory with each facility consuming at least 1.5 GWh annually and having refrigeration as a major portion of the load through the eight-year term of the ESP.

- **Rider NMB Pilot.** The PUCO approved the Non-Market Based Services Rider (Rider NMB) pilot program. FirstEnergy will implement a pilot program for large customers to obtain and pay for services otherwise provided by or through Rider NMB. The pilot program will include Industrial Energy Users-Ohio (IEU) member customers, Ohio Energy Group (OEG) member-customers, Nucor Steel Marion, Inc. (Nucor) member-customers, and Material Sciences member-customers, as well as up to five additional Rate GT customers.

- **EE/PDR.** The PUCO approved FirstEnergy's reactivation of all programs suspended in their EE/PDR Portfolio Plan and a customer engagement pilot program with EnerNoc. FirstEnergy will reactivate in 2017 all programs suspended in their EE/PDR Portfolio

Plan and will expand offerings through the term of the ESP. These offerings will strive to achieve over 800,000 MWH of energy savings annually. Additionally, FirstEnergy will include in their next EE/PDR Portfolio Plan filing a 3-year, customer engagement pilot program to be implemented with EnerNoc to engage small/medium commercial and industrial customers through a software platform customized for FirstEnergy and empower customers to make smart energy choice through customized, timely, and targeted content and actions specific to their businesses. Costs for such programs will be recovered through Rider DSE. The PUCO adopted the following <u>modifications</u> related to energy efficiency and renewable resources:

- Related to the procurement of additional renewable resources in Ohio, the Companies must demonstrate that bilateral contracting opportunities were explored and a competitive process was utilized to source projects.
- The PUCO will eliminate the requirement that the procurement of additional renewable resources must be related to the enactment of new Federal or state environmental laws or regulations.
- The Companies must file a report detailing its strategy to promote fuel diversification and carbon reduction every four years, rather than every five year.

- **EE/PDR Funding.** The PUCO approved FirstEnergy's energy efficiency funding to independent colleges and universities, small businesses, and funding for energy efficiency audits. FirstEnergy will contribute a total of $540,000 to the Council for Small Enterprises (COSE) Ohio Energy Efficiency Resources Program in unrestricted payments over the eight-year term of the ESP, with amounts recovered through Rider DSE from June 1, 2016 through May 31, 2019. FirstEnergy will also contribute a total of $400,000 to the Association of Independent Colleges and Universities of Ohio (AICUO) Efficiency Resources Program in unrestricted payments over the eight-year term of the ESP, with amounts recovered through Rider DSE from June 1, 2016 through May 31, 2019. FirstEnergy may seek approval to recover costs for the period of June 1, 2019 to May 31, 2024 and such approval may not be unreasonably withheld. Finally, FirstEnergy will perform ASHRAE Level II Energy Efficiency Audits (58 in 2016, 100 per year in 2017 through 2013, and 42 in 2014), with all costs recovered through Rider DSE.

- **Increased shared savings cap.** The PUCO approved increased shared savings caps for FirstEnergy. FirstEnergy will increase the caps on shared savings as a result of FirstEnergy exceeding its statutory mandates of energy efficiency from $10 million to $25 million and will continue to be recovered through Rider DSE.

- **Grid modernization business plan.** FirstEnergy is required to file a grid modernization business plan. FirstEnergy filed a grid modernization business plan on February 29, 2016. In a separate proceeding, FirstEnergy will bear the burden of demonstrating that the application is just and reasonable and interest parties may raise any issues regarding the business case.

- **CPA Provision.** The PUCO will disregard the signature of the Consumer Protection Association (CPA) as a signatory party to the Stipulated ESP IV and require FirstEnergy to file proper audit reports to ensure funding is used for its proper purpose. In its brief, OMAEG raised the issue that one of the signatory parties to the Stipulated ESP IV, the CPA, no longer exists and ceases to operate. Given these allegations, the PUCO will disregard the CPA as a signatory party to the Stipulated ESP IV. Additionally, the PUCO adopted the following <u>modification</u>:

- FirstEnergy must file compliance reports (annually at a minimum) regarding the funding provided to both Citizens' Coalition and Ohio Partners for Affordable Energy (OPAE).

- **Modifications.** The PUCO adopted the following additional modifications to the Stipulated ESP IV:
  - The PUCO rejected FirstEnergy's request to include MTEP legacy costs against their legacy RTEP non-collection commitment of $360 million.
  - FirstEnergy is required to file an application in a separate proceeding to modify the Generation Cost Reconciliation Rider (Rider GCR) from bypassable to non-bypassable.
  - If FirstEnergy Corp. moves its corporate headquarters from Akron, Ohio during the term of Rider RRS, the PUCO may terminate Rider RRS.
  - The PUCO removed the provision in FirstEnergy's Stipulated ESP IV that limited refunds for amounts collected through the Alternative Energy Resource Rider (Rider AER) in years prior to the audit year.
  - The PUCO rejected FirstEnergy's proposal to eliminate the ability of CRES providers to request non-summary, customer usage data.
  - The PUCO rejected FirstEnergy's proposed change to add the term "generation" in the supplier tariff provisions regarding consolidated billing. As part of the ESP IV application, FirstEnergy presented revisions to each of the Supplier Coordination Tariffs, including the addition of the word "generation" in order to limit CRES charges on the consolidated bill for demand response or energy efficiency offerings.
  - The PUCO rejected FirstEnergy's proposed change to the supplier tariff related to unaccounted-for energy, which would have removed FirstEnergy responsibility for unaccounted-for energy and placed all responsibility on CRES providers.
  - The PUCO adopted the recommendation to establish a zero-based rider to unbundle the costs FirstEnergy incurs from distribution rates that are required to support SSO service and reflect those costs in the SSO price.
  - The PUCO required the Companies to collaborate with Staff to develop a phase-in-plan for non-residential customers who are projected to experience more significant rate increase, to be implemented during the term of ESP IV.

- **Corporate Separation.** The PUCO rejected arguments that the settlement violated corporate separation requirements and is preempted by federal law. While the PUCO recognized that FirstEnergy could enter into a contract with an affiliate in order to give the affiliate a competitive advantage, the PUCO noted adequate safeguards, such as annual prudency review, were in place to safeguard against any anticompetitive behavior by FirstEnergy. OMAEG and others contended that the PUCO was preempted from authorizing cost recovery under Rider RRS because it would interfere with FERC's exclusive power to oversee the wholesale markets. The PUCO declined to address the argument of whether Rider RRS was preempted by the Federal Power Act and determining that Rider RRS is authorized under state law. Further, the PUCO explained that they do not have authority to declare a statue unconstitutional. OMAEG and other opponents also argued that the projected costs of Rider RRS and other provisions of FirstEnergy's Stipulated ESP IV demonstrated that a Market Rate offer (MRO) MRO was more favorable in the aggregate than the ESP. The PUCO, however, found that the Stipulated ESP IV contained multiple benefits not found in an MRO (e.g., rate stability, modernization of the grid, and promotion of competition). Further, the PUCO found that the Stipulated ESP IV is more favorable than an MRO by $307.1million, representing the sum of a predicted $256 million in net revenue from Rider RRS and $51.1 million in committed shareholder funding over the eight-year term of the ESP.

Concurring Opinions of Commissioner Haque and Commissioner Trombold.

Commissioners Haque and Trombold issued concurring opinions in the Opinion and Order in this proceeding. Both Commissioner Haque and Commissioner Trombold emphasized that the Opinion and Order is based on an expectation that the Rider RRS will result in a credit to ratepayers over the eight-year term of the ESP.

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Summary of HB 554 Provisions Addressing Renewable Energy Standards, Energy Efficiency Standards, Peak Demand Reduction Programs, and Opt-Out Availability

Renewable Energy Standard (Freeze)

- The bill is a permanent freeze on the renewable energy standard.
- It is frozen through 2027 at current levels (2.5% for all renewable energy; .12% for solar) (although there seems to be a typo in one of the sections (4928.64(C)(2)(b)) that references 2.38% (In 116)).

Energy Efficiency Standard (Voluntary)

- EE programs are authorized through 2027.
- Benchmark = (Total annual average, normalized kwh sales of the utility during the preceding 3 calendar years * 4.02) – cumulative energy savings achieved since 2009
- If the benchmark calculation is 0 or less, there is no EE requirement, but utilities can achieve EE savings voluntarily.
- Basically, this will likely make EE all voluntary.

Peak Demand Reduction Programs (Voluntary)

- PDR programs are authorized through 2020.
- Benchmark = (average peak demand on the utility in the preceding 3 calendar years * 4.75) – cumulative peak demand reductions achieved since 2009.
- If the benchmark calculation is 0 or less, there is no PDR requirement, but utilities can achieve PDR reductions voluntarily.
- The average peak demand may be reduced by the PUCO to reduce for new economic growth.
- Average peak demand shall exclude customers on reasonable arrangements and those who have opted out of EE/PDR POR.
- Basically, this will likely make PDR all voluntary.

Opt-out (Expanded)

- All mercantile customers may opt out of the opportunity and ability to obtain direct benefits from the utility's portfolio plan.

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Energy Market Update

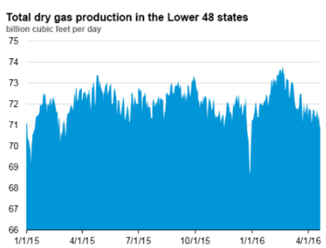
May 2016

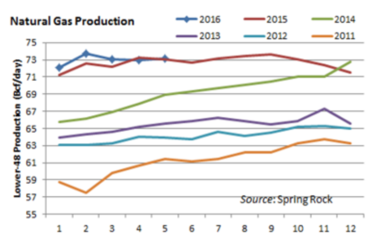
scioto energy

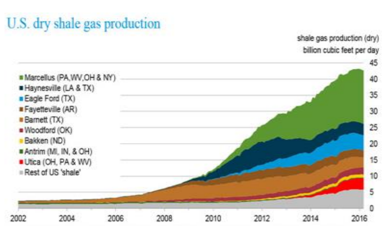
PEAK PERFORMANCE

Electric Market Update
May 2016

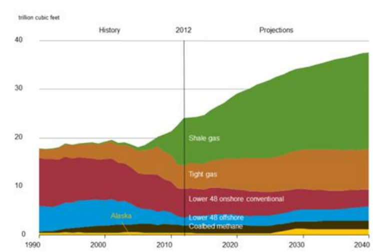
Natural Gas Production



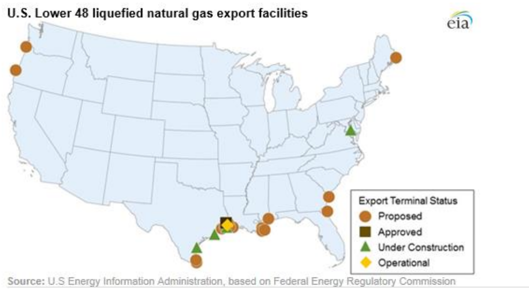




Sources: EIA derived from state administrative data collected by DrillingInfo Inc. Data are through March 2016 and represent EIA's official shale gas estimates, but are not survey data. State abbreviations indicate primary state(s).

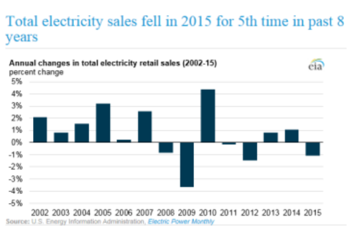


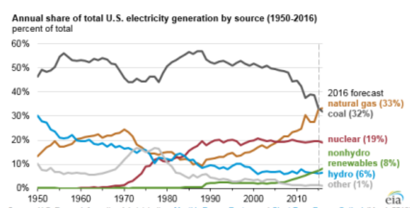
First LNG Export

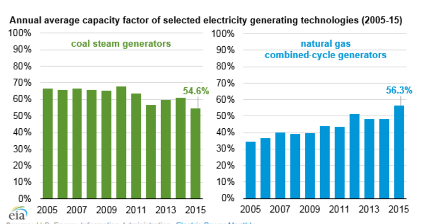


The four LNG terminals under construction would export the equivalent of 40% of Marcellus daily production. Online dates are 2017 – 2020.

Electricity Consumption and Production

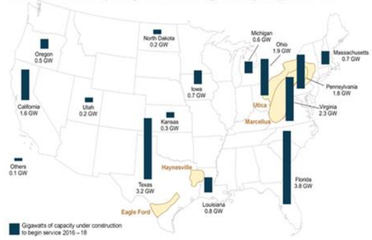


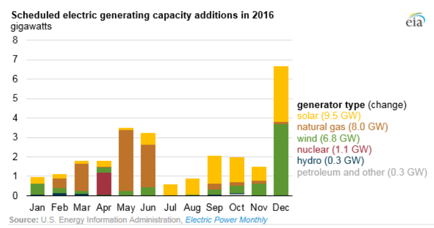


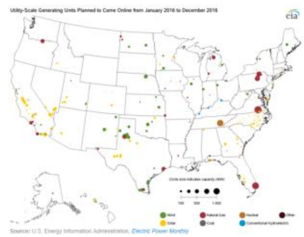


New Generation

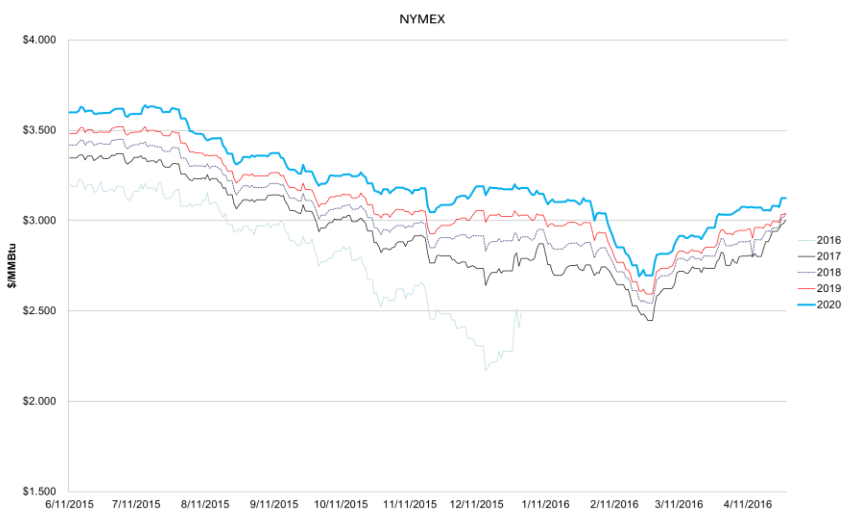
U.S. gas-fired capacity additions by state (GW), 2016-18





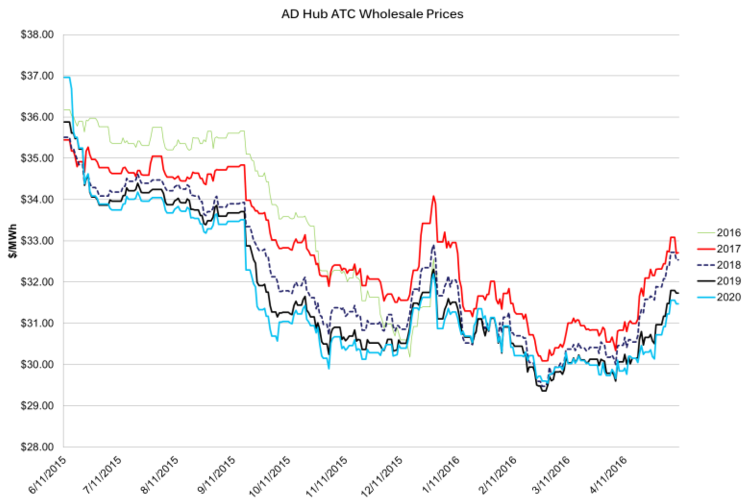


Electric Market Update
May 2016



PERFORMANCE

Electric Market Update
May 2016



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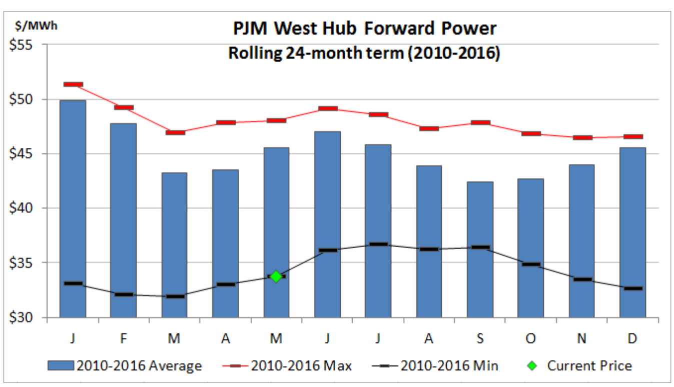
Electric Market Update
May 2016



Natural Gas Update
OMA Energy Committee

Richard Ricks
NiSource
May 26, 2016

Columbia Gas of Ohio
A NiSource Company

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Agenda

- Weather & Degree Days
- Gas Storage & Pricing
- Domestic Gas Production & Rig Counts
- Energy Related Developments

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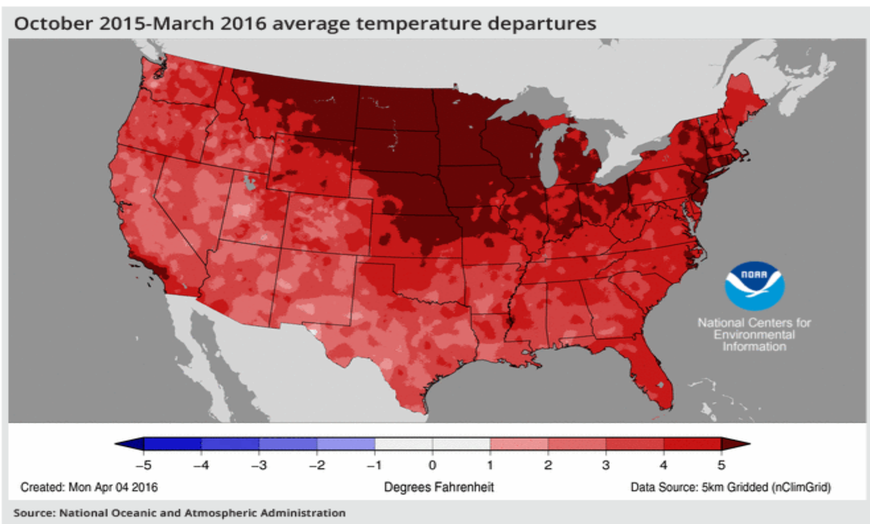
Weather & Degree Days

The 2015/2016 winter was basically the warmest on record



Ohio Winter Season Degree Days 2015/2016

Degree Days Vs. Normal

Month	Actual	Normal	% Variance
Nov 2015	521	668	-22 %
Dec 2015	679	1,037	-35 %
Jan 2016	1,139	1,198	-5 %
Feb 2016	921	975	-6 %
Mar 2016	569	792	-28 %
TOTAL	3,829	4,670	-18 %

Negative variance is warmer than normal

December 2015: Warmest December on record

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A NiSource Company

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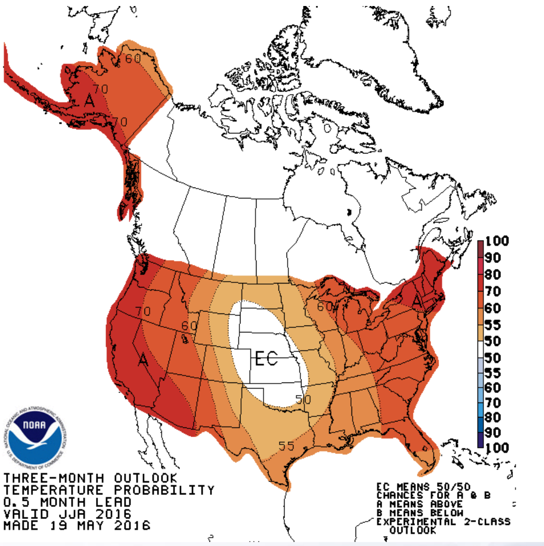
June, July, August 2016 Temperature Outlook



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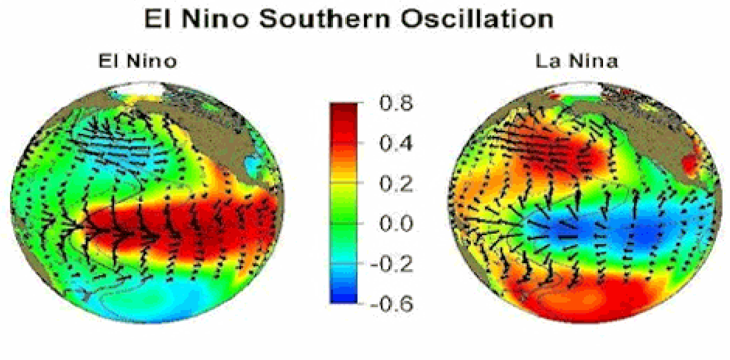
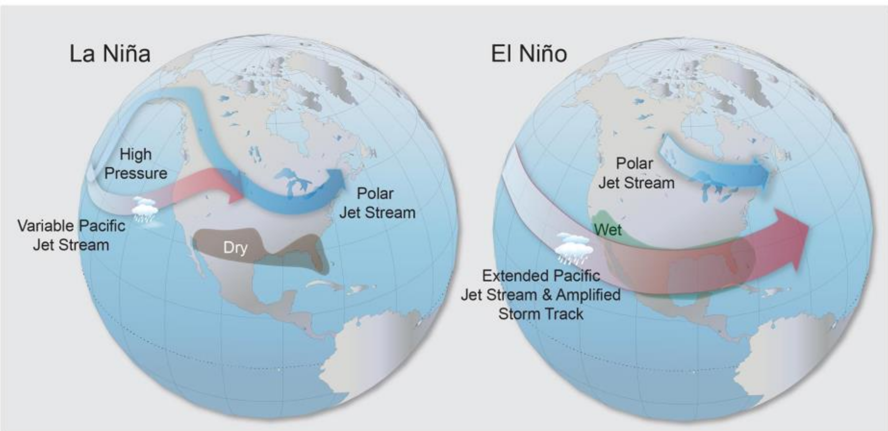
La Nina versus El Nino

La Nina now setting up in the Pacific Ocean
Typically associated with Colder Winters



La Nina versus El Nino

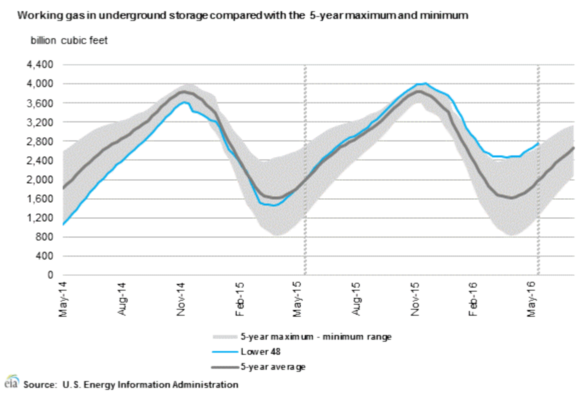
La Niña and El Niño Patterns



Storage & Gas Pricing

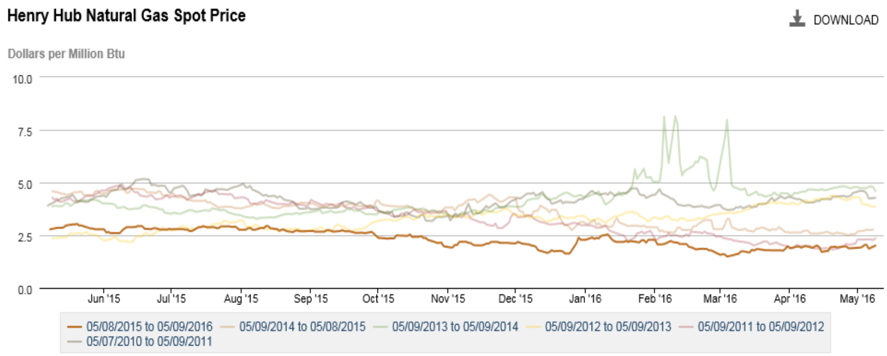
SUMMARY

Working gas in storage was 2,754 Bcf as of Friday, May 13, 2016, according to EIA estimates. This represents a net increase of 73 Bcf from the previous week. Stocks were 791 Bcf higher than last year at this time and 795 Bcf above the five-year average of 1,959 Bcf. At 2,754 Bcf, total working gas is above the five-year historical range.



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2011 through 2015. The dashed vertical lines indicate current and year-ago weekly periods.

NYMEX Prompt Month Settlement – 5 Years



THOMSON REUTERS

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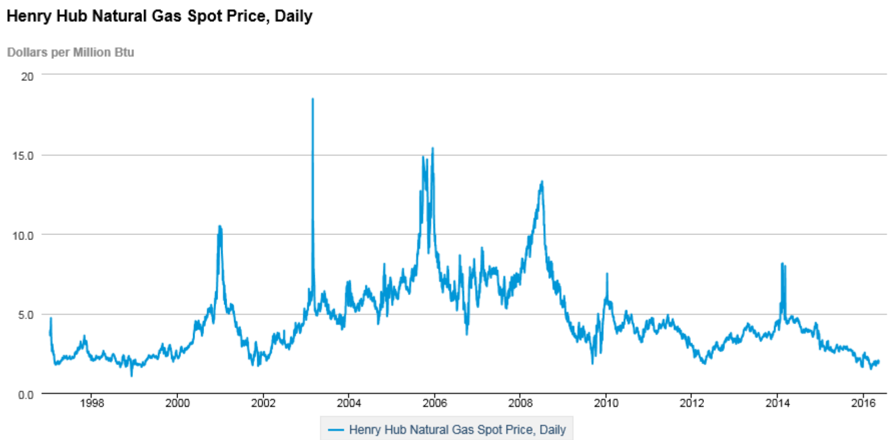
NYMEX Prompt Month Settlement History



THOMSON REUTERS Source: U.S. Energy Information Administration

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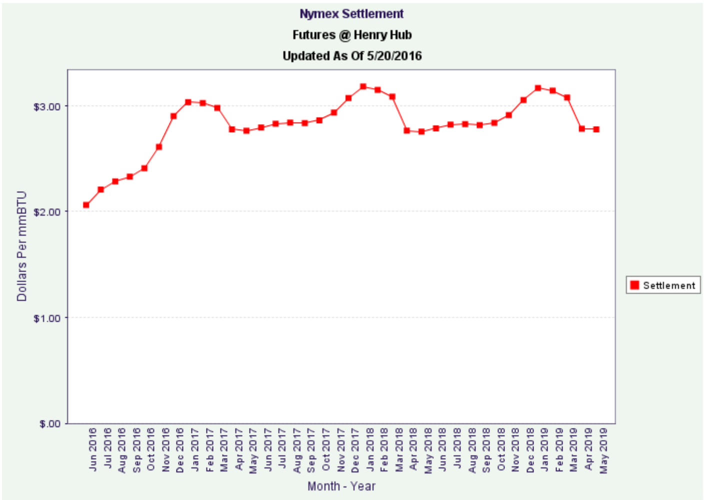
NYMEX Futures Settlement



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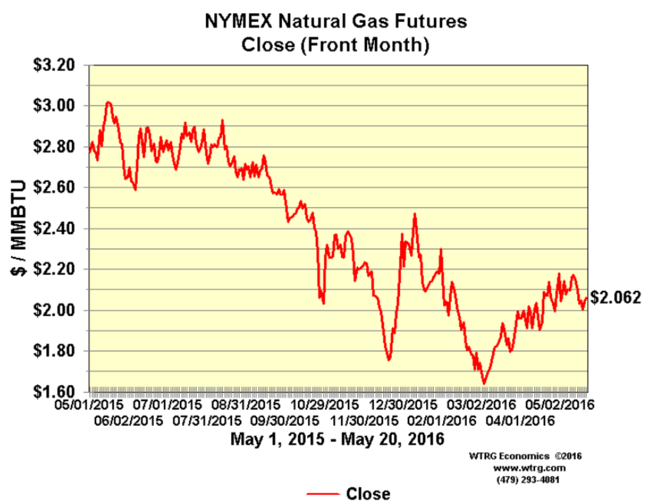
Natural Gas Futures Pricing



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NYMEX Term Pricing – May 20, 2016

TERM	PRICE 5-20-16	PRICE 2-19-16
3 month	$2.18	$1.93 (+$0.25)
6 month	$2.32	$2.03 (+$0.29)
12 month	$2.61	$2.23 (+$0.38)
18 month	$2.69	$2.33 (+$0.36)

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Select Hub Pricing
February 19, 2016

HUB LOCATION	PRICE	PRICE 2-19-16	
Henry Hub	$1.82	$1.88	(-$0.06)
TCO Pool	$1.74	$1.76	(-$0.02)
Houston Ship Channel	$1.74	$1.78	(-$0.04)
Dominion South Point	$1.33	$1.35	(-$0.02)
TETCO M-3	$1.30	$1.41	(-$0.11)
TGP Zone 4	$1.27	$1.19	(+$0.08)

Dominion, TCO, TETCO, & TGP pricing is Marcellus Area

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Production & Rig Count

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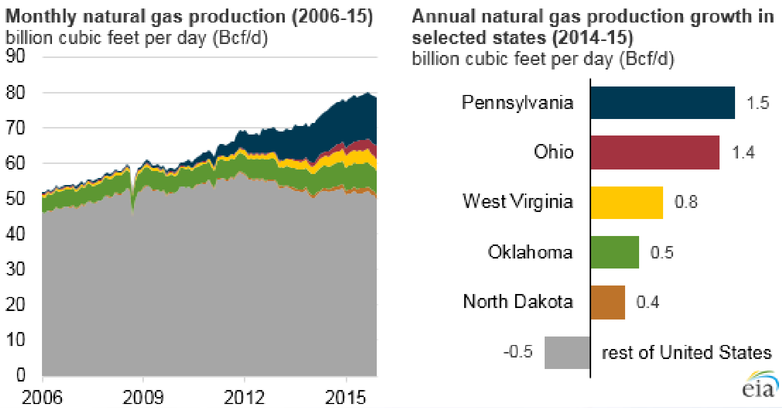
U.S. Natural Gas Production Reaches Record High in 2015
Five States Responsible for Most of the Growth



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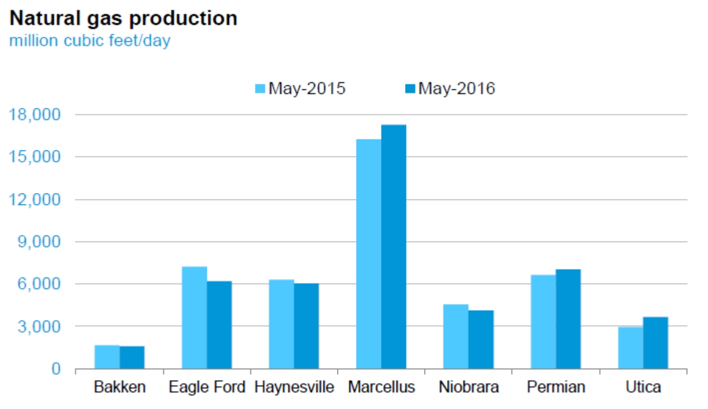
Shale Field Production Data
May 2015 versus May 2016 (projected)



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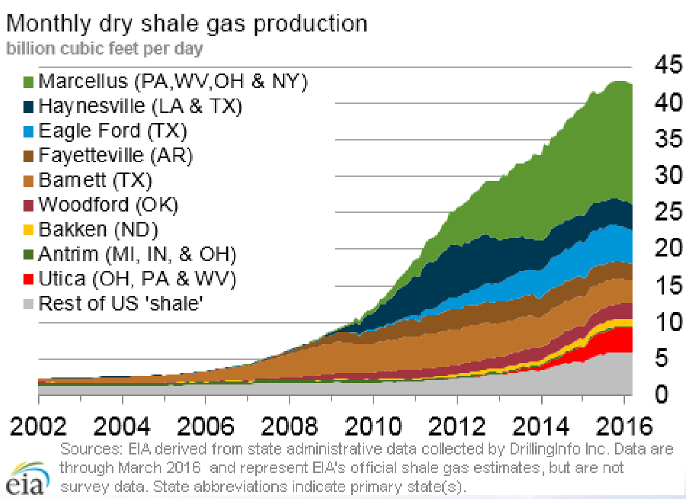
Marcellus – Current Dominant Unconventional Play in Northeast Region



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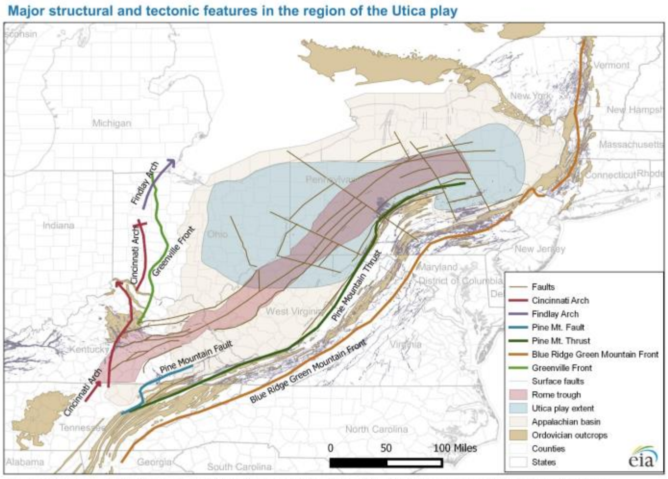
Utica Play Spans 60,000 Square Miles Across Ohio, West Virginia, Pennsylvania and New York



Source: U.S. Energy Information Administration, based on DrillingInfo Inc., IHS Inc., The Appalachian Oil and Natural Gas Research Consortium, and U.S. Geological Survey.

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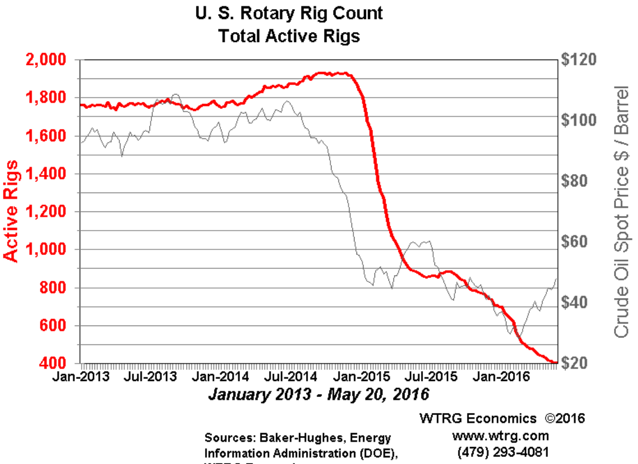
Short Term Active Rig Count



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2016 World Wide Rig Count

BAKER HUGHES INCORPORATED

WORLDWIDE RIG COUNT

2016	Latin America	Europe	Africa	Middle East	Asia Pacific	Total Intl.	Canada	U.S.	Total World
Jan	243	108	94	407	193	1045	192	654	1891
Feb	237	107	88	404	182	1018	211	532	1761
Mar	218	96	91	397	183	985	88	478	1551
Apr	203	90	90	384	179	946	41	437	1424

Related Developments

Developments to be Aware of

- **"Rejected" Pipeline Projects**
  - Keystone (TransCanada; Canada to OK & TX)
  - Constitution Pipeline (Williams & Cabot; PA to NE)
  - Palmetto Pipeline (Kinder Morgan, GA)
  - NE Direct Pipeline (Kinder Morgan, Mass)
- **Activists protesting at FERC meetings & at the FERC members residences**
- **Ongoing consolidation in Energy E&P entities**
  - Low energy pricing environment
  - Bankruptcy and reorganization

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Thank You

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