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Ari Peskoe's Remarks at the Workshop for PJM States and Stakeholders

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Good afternoon. Thank you for providing me with the opportunity to be with you today and to share some thoughts on the intersection of state generation policies and the PJM capacity auction. I'm going to spend most of my time talking about two legal issues:

1) What we've learned from federal courts about state authority to subsidize power generation and
2) FERC's pending decision on PJM's capacity market and what the issues might be in a federal court challenge

After discussing these legal issues, I'll try to identify a market design goal that might gain traction among PJM and stakeholders for the future of the regional market and connect that goal to a PJM-administered carbon price -

FERC and state public utility regulators share a core function – they set rates. When Congress gave FERC authority over transmissions and wholesale sales, the federal role was rather narrow. FERC regulated utility-to-utility sales, leaving states to regulate all other aspects of the power industry.

FERC's ratesetting mechanisms have changed considerably over the years as the volume of transactions under its jurisdiction has increased. Today, rates in RTO markets like PJM are set by supercomputers that optimize dispatch of generation and demand resources by creating Locational Marginal Prices, or LMPs. States, by comparison, are still using pad and paper.

This wholesale price-setting mechanism determines which resources provide service at each instant and are intended to signal to generation and transmission developers where investment may be profitable.

Those long-term price signals are constrained by state and local authority. For instance, just because wholesale LMPs indicate that new generation will be profitable at a particular location, that doesn't mean that development is possible. States site all electric infrastructure not on federal lands, except nuclear and hydro plants, and can reject siting permission for even the most economically rational of investments. These sort of indirect effects on the federally regulated wholesale market are legally uncontroversial. No one

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seriously contends that FERC's duty to set just and reasonable wholesale rates could preempt state siting authority.

But what happens when state action more directly affects the investment signals that wholesale markets are supposedly sending? Recent cases about New York and Illinois Zero Emission Credits tackle this issue and give us a clearer picture of what states are allowed to do.

The headline takeaway from these cases is that states have broad authority to subsidize power generation, even where generators receiving the subsidy sell energy to RTO markets. Now for the backstory on how we got there.

The Electric Power Supply Association, or EPSA, the trade group for merchant generation companies, filed suits in federal court in late 2016 and early 2017 challenging these state policies. Its theory of the case about ZECs was that they displaced FERC's just and reasonable rate. EPSA argued that the ZECs – which essentially require utilities to pay generators for each megawatt-hour of nuclear generation – are state-mandated bonus payment for each megawatt hour of energy sold at wholesale in federally regulated markets. Because federal law says that only FERC can regulate wholesale rates, EPSA argued that the ZEC programs are preempted.

More precisely, its Supreme Court petition argued that states may not guarantee a generator a rate different from the RTO auction price regulated by FERC. EPSA made the same argument in 2016, in the Hughes case, which was about a Maryland PSC order that required utilities to pay a natural gas fired generator the difference between the state's price and the PJM price. The Hughes Court did not directly address EPSA's theory and decided the case on a very narrow basis. The Court's April decision not to review the ZEC cases similarly does not address EPSA's test. So perhaps one day the Supreme Court will accept this line between FERC and state authority and prohibit any state-mandated payment provided on a per-megawatt hour basis. But thusfar only lower courts reviewing ZEC policies have actually addressed EPSA's argument, and they have rejected it.

This rejection is significant because it not only means ZEC policies are legal, it also suggests renewable portfolio standards present little preemption risk, a thing no one was actually worried about until EPSA indirectly raised the issue in these ZEC cases.

Under the ZEC decisions, a state may order its utilities to purchase energy credits from a generator that represent attributes of power, such as its lack of emissions, so long as the state does not order the generators selling those credits to bid into the FERC-regulated auction. That's essentially how RPS programs operate. The state requires the utility to buy RECs and doesn't make REC production contingent on a generator's sales into an RTO.

The ZEC decisions reject the argument that a state's mandate to purchase energy credits changes the FERC-regulated wholesale rate. Put differently, in awarding energy credits to certain generators and mandating utilities buy them, the states are not regulating wholesale rates.

Courts reviewing ZECs found it relevant that ZEC sales are independent of wholesale energy sales. This formal separation between the state's mandate on utilities and the generator's sale to a FERC-regulated market operator like PJM allowed the states to claim that they are regulating electricity production and not wholesale sales.

Drawing a legal line that prohibits states from explicitly tying subsidies to wholesale sales is legally sensible, even if it makes little economic sense. FERC must determine whether wholesale rates are just and reasonable. In RTOs, FERC does so by overseeing auctions. It is uncontroversial that states like California and New York that have their own ISOs may not regulate their auctions. Only FERC can. A state's requirement that a generator benefiting from a state subsidy participate in an RTO auction inserts the state into the wholesale price formation process. Separating the subsidy from the wholesale sale makes RTO participation the resource's choice, not the state's mandate.

By classifying energy credits as production subsidies, the ZEC Courts' maintained the status quo between states and FERC. States have been requiring utilities to buy energy credits for two decades, and, as I said, the ZEC decisions suggest that such mandates are permissible. This is definitely good news for states that enforce these programs.

Two final points on preemption: First, the ZEC courts did not decide whether connecting subsidies to actual wholesale rates is permissible. Under New York's rules, ZEC prices can change every two years based on forecasts of wholesale prices. As forecasted prices go up, the ZEC price goes down. The appeals court contrasted this approach with the Maryland payments, whose amounts were directly tied to actual rates produced by PJM auctions. A future state policy that connects state mandated payments to actual FERC-regulated rates presents some legal risk. There's a bill pending in New Hampshire that connects baseload RECs, which are awarded to in-state biomass plants, to actual wholesale revenue. A lawsuit about that bill (assuming it becomes law) might be the next frontier in Federal Power Act preemption lawsuits.

Second, the ZEC cases, along with other recent federal appeals court decisions, hold that effects of state programs on RTO markets are not a basis for preemption. State mandates may change supply and demand fundamentals and indirectly alter prices. Those economic effects are not relevant to the court's legal inquiry. They may be relevant to FERC, as it sets just and reasonable wholesale rates.

Turning now to how FERC might order PJM to set capacity rates, its June 2018 order finding the capacity market rules unjust and unreasonable suggests that the next iteration of PJM's capacity market will include two elements:

1 – A MOPR that will effectively exclude some state-sponsored resources from receiving a PJM capacity commitment.

2 – A resource-specific FRR that allows resources and a commensurate amount of load to exit the market.

Combined, these two rules would shrink demand in the capacity auction – fewer resources would be paid through the auction, as some load leaves and procures capacity outside of the auction. The resources that do clear would be predominantly, if not exclusively, owned by merchant generation companies and utility holding companies.

FERC's order will undoubtedly be challenged in a federal appeals court. Before I speculate on the legal issues in that challenge, a quick procedural point – This case is years away. Courts will not entertain a legal challenge to a FERC order until FERC issues its rehearing order. In the parallel ISO-NE proceeding on state policies and market rules, FERC issued its order in March of 2018 that set just and reasonable wholesale rates and has not decided rehearing requests. ISO-NE held its first auction under the new rules, although FERC could still decide that those rules are unjust and unreasonable or a court could overturn FERC's order approving those rules. These markets exist with this sort of uncertainty – a point I'll come back to later.

It's unlikely that a federal appeals court will rule on FERC's upcoming PJM order until 2021, which sounds farther away than it really is, and I think there's a good chance the case isn't decided until 2022. I wonder if there is a change of administration in 2021, whether a new set of FERC Commissioners might urge the court not to issue a decision because it's going to revisit wholesale market regulation, just as this EPA has urged the DC Circuit not to decide pending Clean Air Act cases.

One legal challenge for FERC will be drawing a MOPR eligibility line that is not arbitrary. The MOPR, or minimum offer price rule, has been part of capacity markets since FERC authorized their creation in 2006. The rule subjects bids from certain generators to heightened scrutiny by the market operator or market monitor and resets their bids to an administratively determined level that is intended to insure the generators are not intentionally under-bidding in order to reduce the auction prices. The original purpose of the MOPR was to prevent buyer-side market power. The MOPR has been applied to an exceedingly small set of new resources – in other words, resources that are under development that had not yet cleared any capacity auction.

In this proceeding, FERC has suggested to PJM that it vastly expand the MOPR and apply it to existing resources that receive out-of-market subsidies. Which resources and which out-of-market payments are at issue.

FERC has heard a wide range of views on which types of revenue ought to subject a generator to the MOPR.

Merchant generators, for example, argue that generation owned by vertically integrated utilities should be subject to the MOPR. Dominion plants in Virginia, for example, benefit from state-set retail rates that provide construction work in progress financing and an ROE. Those are, without a doubt, out-of-market state subsidies. Obviously, vertically integrated utilities disagree. Dominion supports a “Self-Supply MOPR Exemption” on the theory that integrated utilities “do not engage in the anticompetitive bidding behavior” and citing FERC orders that endorse that proposition.

There are other lines FERC might draw. Some parties argue that any resource selling a REC should be subject to the MOPR. Others disagree, arguing that there are competitive markets for RECs and the MOPR should only target uncompetitive unit-specific subsides, like ZECs, a position that FERC has previously rejected. In addition, parties point out that some coal plants earn revenue from selling coal ash – why should those plants be treated differently from wind and solar facilities selling RECs? RECs and coal ash are non-power or capacity products that generators that use particular technologies can create.

And what about new natural gas fired power plants receiving economic development incentives handed out by Pennsylvania, Ohio and other states? Or should FERC ignore state tax codes, as it ignores numerous differences in state regulations of power plant development and construction?

FERC will, I assume, conjure up rationales for excluding some state or federal out-of-market incentives but not others. I suspect that the more technical the reason, the more likely a court will defer to FERC’s judgment. So it’s probably hard to beat FERC on this point in federal court, unless FERC really screws this up and doesn’t provide any justification for leaving certain resources in or out.

If FERC accepts a broad MOPR without a resource-specific FRR, it must explain why it’s abandoning the connection between capacity rates and reliability or resource adequacy. When FERC approved the settlement agreement that created the Reliability Pricing Mechanism, as PJM calls the capacity construct, it repeatedly tied the new auction to PJM’s responsibility “for ensuring that its system has sufficient generating capacity to meets its reliability obligations.”

If you go through FERC's orders over the years about RPM rules, ensuring resource adequacy and reliability is a consistent theme. Three years ago, FERC summarized that "PJM capacity market's fundamental purpose to help ensure reliability through resource adequacy, because resources are compensated based on their contributions to system reliability." (Capacity Rehearing at P 28).

The effect of excluding existing resources without reducing the size of the capacity market through a resource-specific carve-out is that PJM will buy more capacity than the region needs, by a longshot. Under a broad MOPR, PJM will exclude gigawatts of existing capacity from receiving a capacity commitment, while likely awarding commitments to new natural gas plants. In other words, FERC will pay for new entry while entirely discounting the reliability and resource adequacy attributes of at least four nuclear plants and numerous wind and solar plants throughout the region.

The capacity auction will no longer be "compensating resources based on their contributions to system reliability," as FERC has summarized. Federal agencies are allowed to change their policies, but they must provide a reasoned basis for doing so. The capacity construct will be completely untethered from reliability or resource adequacy, and FERC can't pretend otherwise.

Under this scenario, capacity auction rules would be fine-tuned to finance a particular type of investor that will predictably build a certain type of resource. It would transform capacity development from an area of exclusive state authority into an RTO-driven process.

Electric industry restructuring in the 1990s – characterized by opening or discarding the vertically integrated utility model – aimed to diversify the risks of generation development. In the 1970s and 1980s, ratepayers across the country paid for bad utility investments, particularly in wildly expensive nuclear plants. Under state ratemaking regimes, ratepayers bore some of the risk of utility mismanagement.

By separating power generation from delivery, industry restructuring aimed to shift the risk of generation development away from ratepayers and on to generation developers. But only a handful of states actually moved generation out of utility ratebase. States developed other models. States with vertically integrated and wires only utilities increasingly looked to competitive RFPs and energy credit mandates.

PJM initially included only restructured states. But PJM quickly expanded to include states with vertically integrated utilities. Less than 10 years after its energy market opened, PJM abandoned an energy-only construct and held its first capacity auction. In approving this new capacity procurement mechanism, FERC never suggested that the PJM capacity auction would effectively displace all other generation financing models.

A broad MOPR without a resource-specific carve out would be a concession that today's hybrid market is unworkable and would favor one particular generation financing model.

Only half of generation capacity in the PJM region is owned by pure merchant generation companies. The other half is roughly split between vertically integrated utilities and utility holding companies, such as Exelon. Even restructured states that implicitly endorsed the merchant model in the 1990s, such as New Jersey and Pennsylvania, continued to develop generation through utility mandates. Every single state in PJM has and continues to subsidize electric generation in some form – whether through traditional vertical integration, energy credit mandates, or other programs.

PJM candidly disclosed in one of its recent capacity auction filings at FERC that its primary goal in proposing new rules is to create a market conducive to private equity investment. It explained in that filing that virtually every major publicly traded merchant generation company (as distinct from utility affiliated merchants), over the last 10-15 years has declared bankruptcy. Today, there are only two publicly traded merchant companies left – NRG and Vistra. Private equity investors have purchased existing assets and dominate new builds.

Two years ago, NRG's CEO said that the merchant generation model is "obsolete and unable to create value over the long term." The former CEO of Dynegy – a company that merged with Vistra last year – explained shortly after that transaction that "The underlying market is deteriorating, and with the private equity firms, I don't know how they're going to make out through all of this because they're on a melting ice cube, and they know it."

Are these new investors in it for the long-term, or is putting in new PJM rules part of an exit strategy? What's the future of the merchant industry? Is its future contingent, as these companies argue, on FERC creating an exclusive walled garden for merchant investors? And does FERC have legal authority to do that?

Federal law explicitly provides FERC with authority over wholesale energy sales. FERC has authority over capacity auctions because they directly affect energy rates. The 2016 Supreme Court case about demand response holds that when FERC exercises authority over practices that directly affect wholesale rates to improve the wholesale market, its actions may substantially affect state-regulated matters, such as retail rates.

Here, FERC's creation of an exclusionary federal capacity financing mechanism clearly has implications for state programs. Under the demand response decision, those effects have no legal consequences.

FERC will argue that creating an capacity auction designed to benefit private equity investments in natural gas power plants improves the wholesale market by ensuring those dollars continue to flow into the market. Hence, FERC has authority regardless of the effects on state authority.

A counterargument should articulate a legal line that FERC may not cross when attempting to exercise authority over practices or rules that directly affect wholesale energy rates. The argument might depend on precisely which resources FERC excludes. I suspect that opponents of FERC's order will develop a clear legal line once FERC actually issues its order.

One quick point on the second aspect of the capacity auction that FERC suggested – the resource-specific carve-out. EPSA has previewed one legal argument in its filing last October in this proceeding at FERC. It argues that when FERC finds a tariff unjust and unreasonable, as it has done here, FERC's remedy must be limited to the aspect of the tariff found to be unlawful. Last June, FERC found PJM's tariff unjust and unreasonable because the MOPR does not address out-of-market payments to existing resources. EPSA argues that FERC's remedy may only address the price-suppressive effects of state policies. The resource-specific FRR, according to EPSA, exacerbates price suppression and is therefore beyond the scope of this proceeding.

Whatever FERC does decide, PJM has told FERC that it will conduct the next auction under rules that FERC has found unjust and unreasonable. PJM asked FERC to clarify that it will not annul the auction results and require PJM to re-run the auction under new rules. Numerous utilities asked FERC to require PJM to delay the auction until April 2020, when, presumably, new rules will be in place.

Parties are, I assume, alluding to FERC's Federal Power Act section 206 authority to order market participants to pay refunds upon a finding that a rate is unjust and unreasonable. The statute says that FERC "may" order refunds, and FERC has said that it prefers not to order refunds in RTO markets. And for obvious reasons – re-running the market and calculating who owes how much would be a mess.

And it's not clear that FERC's refund authority is even relevant here. Refunds are relevant when someone is paying too much. Here, the new PJM rules are intended to result in higher capacity rates. FERC's refund authority can't be used to order market participants to retroactively pay higher rates.

FERC also has authority under section 309 to perform any and all acts consistent with the Act. The section is not uncommon in regulatory statutes – it is intended to ensure that the agency's actions are not strictly confined to the express terms of the statute. FERC has broad authority under 309 to remedy its errors or the misdeeds of others. For example, FERC has used 309 to order payments by entities that violated a utility tariff.

It's debatable whether that section provides it authority to order PJM to re-run the auction. It might. My bottom line: I think there's a low probability that FERC orders a market re-run, although I don't see how today's sitting FERC Commissioners can guarantee that future FERC Commissioners will not attempt to order a market re-run. So I'm not sure whether an order from FERC before the next auction will accomplish anything.

For the remainder of my remarks, I'd like to move past the current proceeding and imagine a world where FERC issues an order that includes the resource-specific FRR and a broad MOPR, and a federal court has upheld the order.

Several merchant generation companies have already told FERC how they'll react – they're going to ask FERC for stranded cost recovery. Like the refund issue, it's not clear to me that FERC has legal authority to order this sort of relief, and even if FERC has such authority, it certainly has discretion to decline to do so.

FERC has provided stranded cost recovery in the past. In in its open access transmission order, FERC limited stranded cost recovery to specific long-term requirements contracts. Utilities seeking recovery had to demonstrate they had reasonable expectations of continuing service under those contracts and a "causal nexus" between the open-access tariff and lost revenues due to a departing customer. Eligible costs had to be associated with serving a specific customer and had to be recovered directly from that departing customer. None of that applies here.

So I think it's unlikely that FERC orders any sort of transition payments to merchant generators, but I can't definitively rule it out. And this will be a blockbuster FERC proceeding. Many billable hours will be billed and economic consultants will produce persuasive reports demonstrating how many billions of dollars merchant companies are owed for their investments that failed to produce expected profits. But I think this will be a hail mary pass that FERC will bat down.

Putting that transition issue aside, would these two changes to the RPM end the tensions between state policies and merchant plant owners? Probably not. But, these two reforms – a broad MOPR combined with a resource-specific carve-out might help to achieve a goal that many stakeholders share. Lower capacity rates might lead to the retirements of inefficient generators.

As of 2017 – so I realize these numbers have changed, perhaps significantly - there were approximately 80 GW of coal or natural gas steam or oil-fired generators that are older than 40 years. Roughly half of the coal capacity and most of the natural gas steam turbines are merchant owned. By my count, the steam turbine capacity is actually older than the coal plants. Of course, this 80 GW or so of capacity is generally the most polluting, and the vast majority need to go offline if the U.S is going to decarbonize. Every megawatt-hour of energy these plants produce must be generated by a less-polluting source.

PJM openly embraces this goal of retiring inefficient capacity, although it defines inefficient a bit differently. In a recent capacity market filing, PJM observes that investors have been pouring money into new natural gas fired generators, even though the region has sufficient capacity. This new entry into the market is explained, according to PJM, is explained by risk-bearing market participants' expectations about future natural gas prices, innovating financing, and the ability of efficient new resources to provide cheaper energy than existing inefficient plants. PJM says that "This kind of investment illustrates precisely how markets unleash competitive forces for the benefit of the consumer."

The problem is not PJM's goal – replacing old power plants with more efficient resources is a widely shared goal. The controversy centers around PJM's focus on the capacity auction.

Instituting a carbon price in the energy market is another avenue achieving this goal of retiring inefficient capacity. A FERC order approving a PJM-administered carbon price would reviewed by a Federal court. I think that FERC has legal authority to approve a region-wide carbon price. The test – again, as with demand response and capacity auctions – is whether the carbon fee aims to improve the wholesale market.

A FERC order approving a PJM carbon price should focus on how the price improves the market, and not the environmental effects of the carbon fee. A carbon price would likely raise energy rates, which would reduce capacity rates and the effects of RECs, ZECs, and other out-of-energy-market payments. Higher energy prices also help nuclear plants, by far the largest source of zero-emission power in PJM and beneficiaries of state programs that PJM and merchant generators loathe. A carbon price checks a lot of boxes.

Consider FERC's legal authority to approve a carbon fee as compared to its authority to approve a broad MOPR without a resource-specific carve-out. That MOPR would divorce capacity prices from reliability. It would transform the capacity auction from a mechanism for achieving resource adequacy into a federal capacity financing mechanism. If FERC's authority to improve the market is so broad that it allows FERC to create a capacity financing mechanism to benefit a specific type of investor that builds certain types of resources, why can't FERC price carbon emissions?

Carbon emissions are a significant industry driver. Emission-free power has value. Private parties – from Google to Anheuser-Busch - are buying it. Numerous utilities have voluntarily committed to reducing their emissions. Tens of billions of dollars are invested each year in emission free power. Myriad state and federal policies support it. What legal limit prevents FERC from recognizing the economic value of emission-free power? Is FERC only authorized to fight against the trend, by excluding those resources that are paid for their emission free energy?

That said, an RTO-administered carbon price would be novel and challengers might argue that a carbon fee departs from the cost causation principle. FERC wholesale rates typically bear some connection to the costs of serving each customer. While carbon emissions surely have environmental and societal costs, as I said, I think FERC is on firmer legal ground if it tethers the carbon fee to improving the market, not mitigating climate change. So the relevant costs here, for purposes of cost causation might be the costs of out-of-market instruments, such as RECs and ZECs, that will be less expensive.

The amount of the carbon adder should be calculated to achieve whatever market improvement goal PJM is aiming for. I don't see any logic to using the social cost of carbon in this context.

As the next panel will discuss, PJM is studying carbon pricing. Its noteworthy that a few merchant generation companies actually teed up this issue before FERC in the capacity market proceeding and asked PJM to initiate this study. But, of course, not everyone wants carbon pricing. PJM should study the feasibility of applying a carbon fee only to generators within certain states. A market bifurcated by carbon fees might not be a good political option – although perhaps it provides a competitive advantage to generators in states with the most polluting mixes.

I'm interested in the feasibility of a fee that applies throughout the PJM footprint but is only paid by load serving certain states. Under this model, the carbon fee is applied uniformly, it affects dispatch across the region, and all generators actually get paid the energy price that includes the carbon fee. But through out-of-market payments, load serving entities in states that opt in to the fee pay load serving entities in other states. So, for example, utilities in New Jersey might pay utilities in West Virginia, which would be a perverse result. But perhaps it gets everyone on board and the effects are actually better than excluding West Virginia generators entirely from the carbon fee.

This arrangement respects the principle that buyers should be able to buy the products they want, as long as they pay for them. The carbon fee would affect all generators – presumably lowering emissions across the region, which is what some states want – and those entities that want this result would pay for it.