Exhibit A
Protest of Clean Energy Advocates, May 7, 2018
Docket No. ER18-1314
PROTEST OF CLEAN ENERGY ADVOCATES

Pursuant to Rule 211 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure,1 the Sustainable FERC Project, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund (“Clean Energy Advocates”) respectfully submit this protest and comment on the Federal Power Act (“FPA” or “the Act”) section 205 filing dated April 9, 2018 of PJM Interconnection, L.L.C. (PJM) proposing two options to increase capacity market rates in response to certain state policies targeted by PJM.2

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1 18 C.F.R. §§ 385.211 and 214.

2 16 U.S.C. § 824d.

ARGUMENT

I. To protect the market from an illusory threat, PJM would give FERC the impossible and improper task of policing state policy.

A. PJM is wrong that competitive markets are under threat.
   1. PJM faces no conceivable threat to reliability.
   2. Policy preferences have always affected market prices.
   3. The positive spillover effects of state policies on other states do not justify tariff revisions to insulate the PJM capacity market from those effects.
   4. Even assuming there were a threat, PJM's proposals do not aim at the actions allegedly causing it.

B. PJM wrongly puts the Commission in the position of policing the efficiency of state policies.
   1. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix.
   2. PJM, by deeming legitimate state policies that aim to address market failures as pernicious "subsidies," places wholesale market rules on a collision course with states' core duty to protect the public.

C. PJM's short-sighted contention that state policies threaten its capacity market paradoxically sets the market on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed.

II. Threshold legal and procedural flaws bar the Commission from approving any of the proposed PJM proposals.

A. PJM filed a set of poorly developed proposals flouting the principle of stakeholder engagement.

B. PJM's filing is deficient under section 205 of the Federal Power Act.

C. PJM fails to meet its threshold burden to offer a clear rationale for its proposals and substantial evidence to back that rationale.

D. PJM relies on the wrong legal standard and thereby fails to provide the record necessary to approve the proposals.
III. PJM's proposals both fail to meet the standard for the Commission to approve the filing under section 205 of the Federal Power Act.

A. Even under PJM's own flawed standard, PJM's proposals fail on each count.

B. At its core, PJM's proposals are based on arbitrary line-drawing, which results in undue discrimination against certain buyers and sellers.

1. PJM's definition of "actionable subsidy" is arbitrary.

2. PJM carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations.

C. Both capacity repricing and MOPR-Ex are unjust and unreasonable because they require customers to pay more for capacity than necessary to ensure resource adequacy.

1. Capacity repricing inflates capacity rates without benefitting customers.

2. MOPR-Ex forces customers to buy more capacity than needed to provide resource adequacy in PJM.

3. PJM's proposals are not warranted by any market failure.

D. PJM's proposals are not just and reasonable because they increase market uncertainty.

1. The proposals' subjective standard leads to uncertainty.

2. The scope of the RPS exemption is unclear and further clouds market expectations.

3. Market distortions that result from PJM's proposals will force further rule changes.

CONCLUSION
SUMMARY OF ARGUMENT

Clean Energy Advocates urge the Commission to reject both of PJM's proposed mechanisms for addressing what it views as the adverse impacts of state policy on wholesale capacity markets. By design and in application, PJM's proposals target state climate policies, including state Renewable Portfolio Standards (RPS). The proposals fail to meet threshold legal standards for approval under the Federal Power Act. Both proposals are unduly discriminatory and preferential, arbitrarily imposing excessive costs on some customers and not others, and harming some resources and not others without a principled basis. Neither proposal is just and reasonable because both are based on arbitrary line-drawing, would saddle consumers with billions in extra costs without providing any resource adequacy or other benefits, and would increase market uncertainty.

PJM presents the Commission with two ill-conceived, poorly formulated proposals that pose massive implications for the function of the capacity markets, billions of dollars in cost for consumers, and threaten to fundamentally reorder the boundaries between shared federal and state authorities over the interconnected power system. It vaguely suggests a third option may be on the table (it is not), and that if the half-formed proposals it presents to the Commission are not satisfactory, invites the Commission to resolve the core workings of a complex new market design through settlement. PJM drapes its inadequate proposals in false claims of exigency, urging the Commission to adopt at least one, lest the thundering waterfall of investment in the region slow to a trickle, and starve the fat reserve margins down to a reliability risk.

PJM is wrong that its markets are under threat due to state policies. Even PJM acknowledges that the region currently has a tremendous surplus of generating capacity, obviating any concerns that market prices are too low to incent new generation and retain needed existing capacity resources. PJM's latest planning reserve margin for the summer of 2018 is 28.7.
percent—significantly higher than the recommended installed reserve margin target of around 16 percent. When looking forward at expected power builds and retirements, there appears to be no risk of a capacity shortfall in the coming years.

The vast majority of the state policies about which PJM expresses concern have been in place for years. PJM frets about state subsidy programs that in its view, “could have a material price suppression effect in the wholesale capacity market,” but it offers no evidence that the policy actions it targets are, by any measure, more impactful or concerning than the energy subsidies enacted by governments at all levels that have affected PJM market prices throughout its history. As described in the attached report of subsidy expert Doug Koplow, energy subsidies have long been pervasive at both the federal and state level, without attendant impacts on PJM's wholesale markets that have prevented that market from attracting record levels of investment.

Many of the state policies that PJM seeks to thwart have positive spillover effects enjoyed by other states, both by lowering market prices and reducing environmental externalities. Even if one state's policies were to somehow harm customers in other states, that would not justify Commission intervention to countermand those laws where they are lawfully within the state's authority.

By asking the Commission to approve policies that would either discourage or directly frustrate the achievement of state policies fully within the state's authority, PJM's proposal would place the grid operators and the Commission in the position of policing state policies, forcing the Commission to mediate essentially political proposals put forth by entities accountable to utility stakeholders rather than voters. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix; indeed, the historical evidence shows that many
PJM states enacted RPS programs at the same time or shortly after they restructured. This history belies PJM's suggestion that reliance on wholesale market competition to determine resource mix is an all-or-nothing proposition. The MOPR-Ex proposal, in particular, aims to undo state policies that are not designed to adjust energy or capacity prices, but rather to address externalities caused by power production. This runs contrary to the terms on which capacity markets were approved, by which states retained full control to influence the generation mix through RPS programs and other policies.

PJM's proposed actions would set the market on a path toward greater conflict and uncertainty while ignoring options to facilitate the implementation of state policies in more efficient ways. The targeted state policies reflect a change in market fundamentals; more and more, end-users demand zero-emission energy. By adopting a market design that is directly at odds with the direction the market is moving, the Commission would deepen tensions between retail and wholesale objectives, ultimately undermining the competition it seeks to promote and undercutting the relevance of the wholesale capacity market to meeting market demand.

PJM's proposals suffer from numerous threshold legal and procedural flaws that warrant immediate denial by the Commission. First, in bringing this matter to the Commission, PJM ignored the clear preference of its stakeholders to maintain the status quo. Although PJM has authority to make such filings without stakeholder endorsement, doing so means that the Commission is presented with proposals that have not been fully developed and likely do not represent a fair balance among conflicting interests. Second, PJM's ambiguous and multi-faceted proposals, which invite the Commission to choose a path forward, falls short of the specificity required by section 205 of the Federal Power Act. To be properly filed under section 205, a tariff revision must "plainly" state the change sought, be sufficiently definite to take effect by
operation of law, and provide adequate notice to consumers. PJM's filing fails to meet these requirements and should therefore be rejected outright, or at minimum be characterized as a filing under section 206 of the FPA, which would also compel rejection of the filing given PJM's failure to explain or even state that its current tariff is not just and reasonable.

Even if the section 205 standard were to apply, PJM has not put forward substantial evidence to demonstrate that its market design is just and reasonable and not unduly discriminatory or preferential. PJM fails to articulate why it has targeted a particular subset of state policies, whether and by how much they suppress prices in a way that is different from other state policies, or whether the degree to which wholesale prices are affected harms resource adequacy or some other objective enough to justify the extraordinary costs of each proposal. As a final threshold legal flaw, PJM cannot demonstrate its proposals are just and reasonable because PJM relies on a standard that lacks a basis in longstanding Commission precedent and that would leave consumers without statutory protection. By relying on an erroneous, investor-focused standard, PJM fails to address how its proposals will impact wholesale customers and thereby denies the Commission the record it requires to evaluate whether the approach is just and reasonable. PJM's apparent view that what is in investors' interests is in consumers' interests is blatantly inconsistent with the Federal Power Act's clear delineation of the Commission's role in protecting consumers (even if PJM were correct that its proposal is categorically better for investors, which is not the case).

The substance of PJM's proposals is equally flawed. PJM's proposal neither demonstrates, nor is there sufficient basis to conclude, that either repricing or MOPR-Ex will in fact facilitate robust competition; provide the right price signals; result in selection of least-cost set of resources; ensure price transparency; shift risk from customers; or mitigate market power.
PJM's proposals add unnecessary complexity to the capacity market construct through a layer of unworkable administrative judgments about "what is a subsidy" that will cloud market certainty, lead to arbitrariness in price signals, and obscure price mechanics. Absent any principled economic rationale underpinning either market construct, PJM's proposals work to the benefit of certain competitors instead of competition.

PJM's definition of actionable subsidy, which underlies both the repricing and MOPR-Ex proposals, is based on a revenue threshold that even PJM admits may not affect capacity offer prices in all circumstances, much less have an impact on the market itself. PJM then carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations, without offering any rational basis for the different treatment. First, PJM provides an unfettered exemption to its definition of a subsidy for self-supply resources, contrary to its previously expressed concerns about the owners of such resources having incentives to manipulate the market if certain criteria are not met. As PJM has previously acknowledged and as recent examples show, self-supply resources can elbow other, more competitive resources out of the market. Yet PJM gives such resources a free pass, without explaining why resources supported by state programs should be treated differently. Next, PJM proposes to exempt incentives that utilize criteria designed to incent or promote general industrial development in an area, or to incent a generator to site in a particular location. PJM offers no explanation at all for its proposed exemption of general economic development and local siting incentives, despite evidence that such incentives can provide significant support to specific energy assets and affect decisions to enter the market in a particular location. Finally, PJM appears not to apply its definition evenly to all resources, as it omits thousands of megawatts of coal-fired generation resources in Pennsylvania that receive state policy benefit.
that, by PJM's own definition, is "material" and would therefore pose risk of price suppressive effect.
PJM's wholly arbitrary targeting of some state policies but not others with the same potential market effects, has severe and harmful consequences for both market participants and wholesale customers. This discrimination is not based on any meaningful economic rationale or other reasonable distinction, and therefore is by definition "undue."
The arbitrary nature of PJM's proposal results in direct harm to wholesale customers and, under MOPR-Ex, capacity sellers. Under PJM's proposals, wholesale customers in one capacity zone (where resources benefiting from "actionable" policies are located) face price increases while customers in another zone do not (where resources benefit from policies that are not deemed "actionable") – even though both customers are served by capacity resources that receive state benefits that, under PJM's reasoning, would pose the same threat to market competition.
Under MOPR-Ex, market participants who have based their investments on the expectation of the regular application of certain state laws lose out; while at the same time other investors who have relied on state policies that are not deemed actionable but have the same potential market effects do not. To the extent investor expectations are a rightful subject of the Commission's just and reasonable standard at all, PJM's proposal results in exactly the unduly discriminatory application of the standard that is prohibited under the Federal Power Act.
Both repricing and MOPR-Ex would be costly to consumers, and create the possibility for drastically different prices for consumers in different capacity zones. Capacity repricing forces customers to pay more for the same level of resource adequacy by setting prices to what they would have been if state policies did not exist. By design, repricing would set prices higher than the amount necessary to induce the entry and retention of resources that cleared in the
auction's first stage, contrary to the fundamental purpose a capacity market to attract sufficient capacity to provide resource adequacy at least cost to consumers. Capacity repricing is also unjust and unreasonable because it is structured in a manner that will skew market bidding incentives in a manner that would further harm customers, as described in the affidavit of James F. Wilson attached to these comments. Under reasonable assumptions about the quantity of resources that would be repriced, Wilson calculates that clearing prices could increase 50 percent as compared to operation of the PJM capacity market under status quo rules, amounting to a total market cost of $9.1 billion annually. These staggering price increases would not provide customers with any appreciable benefits, and would therefore be unjust and unreasonable.

MOPR-Ex, by PJM's own admission, would require customers to procure more capacity than necessary to meet the region's reliability needs. By ignoring perfectly good capacity developed pursuant to state policies, MOPR-Ex would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers would be receiving value for their money. The costs of this approach are similarly staggering: a rough estimate suggests they could be in the range of $14 to $24.6 billion. The Federal Power Act's requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

MOPR-Ex is fundamentally flawed because not only will it induce entry of more resources than warranted, it sets prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM's glut of supply. Structural problems with PJM's market have already encouraged a massive overbuild of the system at great cost to customers, and MOPR-Ex would make that problem far worse, taking the market in exactly the opposite direction from what is necessary.
MOPR-Ex’s proposed exemptions for certain state policies do not cure these fundamental flaws. In particular, the exemption for state RPS programs is so restrictive that many state-supported renewable resources will fail to qualify despite the legitimacy of the underlying policies. As we detail in Appendix A, there is significant uncertainty as to whether 10 of the 11 RPS programs would meet PJM’s restrictive criteria.

No market failure justifies that dramatic administrative interventions that PJM proposes. PJM points to the participation of resources that benefit from revenues from (some, arbitrarily-defined) state programs as warranting intervention, but it is fundamentally wrong to treat value derived from valid state property rights and obligations as “distortions” of the market. PJM is also simply wrong that the participation of resources receiving such revenues will give rise to a threat to reliability that would warrant market intervention; by its very design, market prices will rise if supply becomes low due to retirements (even assuming those retirements are driven by entry of state-supported resources). Nor does the prospect of buyer-side market power warrant tampering with the market here. To the contrary, long-standing Commission precedent holds that the renewable resources that are a primary target of PJM’s proposals are an exceedingly poor tool to use in seeking to lower market prices. Moreover, because these state actions are driven by other motivations, there is little deterrence benefit of targeting them for mitigation. Finally, PJM is simply mistaken that the market interventions it proposes will have the benefit of shifting risk from consumers to supply. Its proposals will have precisely the opposite effect. For all these reasons, the Commission should reject PJM’s proposals as unwarranted, vastly outweighed by the harms to customer and state interests, and unnecessary to ensure the competition that benefits the public.
Finally, the Commission must also reject PJM’s proposals because they would unreasonably undermine market certainty. PJM’s proposals, of which the lynchpin of each is a subjective and internally inconsistent standard, will only produce greater dispute, litigation, further rule changes, and market confusion going forward. Moreover, the scope of the MOPR exemptions are vague and do not provide clear guidance as to which state policies will be covered, which undercuts investor certainty. Placing PJM and the Independent Market Monitor in the role of determining the scope of an actionable subsidy is likely to be unworkable, and to lead to long, irresolvable disputes. Both proposals lead to market distortions that will create increasing pressure to once again change market rules to correct course, thus providing little prospect of continuity for market participants.

BACKGROUND

I. State policies at issue

At the heart of this proceeding is a series of policies that states have adopted to support the transition to clean energy. Because Clean Energy Advocates interests in this proceeding are particularly linked to the policies that aim to incent the technological innovation, development, and widespread commercial deployment of emergent clean energy technologies (including solar, wind, demand, and storage), we focus our discussion here on those policies.

States employ a wide array of policies to foster the growth of renewable energy, energy storage, and demand response resources. State policies in support of clean energy use a variety of methods to pursue diverse goals, from spurring local economic development and improving ambient air quality to supporting emerging clean energy technologies and fighting global climate change. Many of these state programs incorporate competitive procurement mechanisms and rely on tradable credits that can be exchanged in markets.
A. Renewable Portfolio Standards

Renewable Portfolio Standard ("RPS") programs are well-established mechanisms by which states can encourage growth of renewable energy resources while minimizing cost. Although the details vary greatly from state to state, in broad strokes an RPS works as follows:

First, a state sets progressive annual targets for power from renewable resources to make up an increasing part of its energy consumption. To meet these targets, load serving entities ("LSEs") within the state are required to obtain a percentage of their energy from "renewable" resources. States have different definitions of what constitutes "renewable", in accordance with their policy priorities. LSEs satisfy this obligation by obtaining and using renewable energy certificates ("RECs"), each of which reflects the production of one megawatt-hour of electricity by a renewable resource. An RPS thus creates a market for RECs, in which LSEs obtain RECs from the owners of renewable resources to meet their share of the state's renewable energy target.

States regulate the REC procurement market in different ways. Depending on the program, RECs may be "bundled" and sold together with the underlying energy, or "unbundled" and traded separately. RPS programs may also prioritize certain kinds of renewable resources over others by creating different tiers of RECs or carve-outs for specific resources, as described in further detail below.

Beginning with New Jersey in 1999, ten states and the District of Columbia enacted RPS programs in PJM's footprint. As "inventions of state property law" RPS programs vary greatly, reflective of each state's underlying and particular policy objectives.


extend far beyond carbon reductions, reflecting the diverse goals and priorities of individual states. For example, New Jersey's RPS program is designed to, among other things, "encourage the development of renewable sources of electricity and new, cleaner generation technology; minimize the environmental impact of air pollutant emissions from electric generation; reduce possible transport of emissions and minimize any adverse environmental impact from deregulation of energy generation."

Virginia's RPS program is broadly based on the pursuit of "public interest." Illinois' RPS program is premised on the basis that "environmental benefits of renewable energy generation are mainly associated with the benefits of avoiding the use of conventional generation sources that typically burn fossil fuels and emit regulated pollutants." The Illinois law is intended to not only reduce carbon emissions, but sulfur dioxide, nitrogen oxides, PM2.5 emissions. The law also cites state policy goals including water conservation, adverse land-use impacts, and reductions in "lung diseases such as asthma and chronic obstructive pulmonary disorder."

Michigan's program aims to, among other things, reduce "energy waste" and coordinate "with federal regulations to provide improved air quality."

Because RPS programs are founded upon diverse policy objectives, RPS program design naturally varies greatly from state to state. States reflect their different policy priorities through their decisions in RPS program design, and have charted different courses on decisions such as what types of resources qualify as "renewable", whether all or a portion of RECs should be restricted on a geographic basis, whether any resources should receive different prices from each

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6 N.J.A.C. 14:8-2.1.
8 20 ILCS 688/15, Sec. 1-5.
9 Id.
other or be procured in different ways reflecting their different environmental benefits and other impacts, whether the “banking” of RECs should be permitted to allow for use in future years, what the target should be in each year, and what the consequences should be were an LSE to fail to meet its requirement to procure RECs.

Qualifying Resources. RPS programs do not uniformly allow for the same set of qualifying resources differ by state. For example, whereas North Carolina allows for demand response, New Jersey does not. Indiana allows for clean coal. Qualifying resources often include a number of megawatt and entity specifications. Illinois limits qualifying distributed generation, for instance, to 2 MW or less; North Carolina limits hydropower resources to 10 MW or less.

RPS programs can also include several resource tiers to allow the state greater ability to further the particular policy goals they seek. Maryland, for example, includes hydroelectric power as a Tier II resource, which Delaware classifies it as a Tier I resource. Other state resources focus to a greater extent on waste reduction measures, such as Michigan, which includes “energy efficiency, load management, and energy conservation” as Tier I qualifying resources. Moreover, some states have designed their program to ensure particular standards in manufacturing are met. In the District of Columbia, for example, solar thermal installations must use Solar Rating and Certification Corporation certified components to qualify.

Geography. Resource eligibility can also vary based on geography. Frequently, states allow RECs from resources from across the PJM footprint to satisfy their RPS targets. For

12 Ind. Code § 8-1-37.
16 D.C. Code § 34-1431 et seq.
example, Pennsylvania's RPS states, "for purposes of compliance with this act, alternative energy sources located in [PJM] or its successor service territory shall be eligible to fulfill compliance obligations of all Pennsylvania electric distribution companies and electric generation suppliers."

Notably, this language dates to 2007, contemporaneous with the beginning of PJM's capacity market. The District of Columbia likewise allows for resources from within and adjacent to PJM's service territory to provide RECs.

In contrast, Indiana requires that 50% of qualifying energy be obtained from within the state.

Delaware's RPS program takes a different approach, providing credit multipliers for resources that meet certain geographic criteria that encompass and contemplate manufacturing origin.

RPS Programs may also preference certain types of generation in ways other programs do not. Delaware, for example, has a 3.5% solar target. Michigan provides a credit multiplier for renewable energy generated during hours of peak demand.

Maryland and New Jersey have carve-outs calling for a certain percentage of their RPS to be met by RECs from qualifying offshore wind resources.

Competitive procurement mechanisms and banking. States have different mechanisms for how the RECs may be bought and sold and when they may count toward the target in a particular compliance year. A majority of states in PJM use a common "generation
attribute tracking system" (GATS) to track RECs across the PJM jurisdiction. GATS enables states who use it to track the attributes of all registered generators within PJM, as well as some located outside but interconnected to PJM. Under the majority of state programs, some or all RECs may be purchased by Load-Serving-Entities from generators with eligible attributes throughout the PJM footprint, or beyond, through the REC market. Thus, while demand is, in effect, set by the strictness of the RPS targets, eligibility requirements, and cost containment mechanisms (such as the availability of alternative compliance payments), within these parameters generators compete in the market to supply RECs. The REC market is one means states use to ensure competition drives down costs of procurement to consumers. Not all states use a tradable REC market as the means of procurement. Illinois, for example, relies on the Illinois Power Agency to purchase RECs. Even where state programs goals cannot be met through open trading of RECs on the market, states commonly use alternative competitive procurement mechanisms. For example, with the aim of enabling the development of a promising but still nascent (in this country) offshore wind technology, the Maryland Public Service Commission employed a competitive bidding process. Where RPS programs allow for tradable RECs, states make varying decisions as to whether they can be "banked" for use in future years. In Delaware, for example, RECs last for 23 GATS is operated by an unregulated PJM affiliate. Michigan and Ohio do not use GATS, but have their own systems to track RECs. PJM Independent Market Monitor, State of the Market Report at 318 (2017). ("SOM 2017") 24 Id. at 312, Table 8-12. 25 20 Ill. Comp. Stat. Ann. 3855/1-5 (A)-(H). 26 See In the Matter of the Applications of US Wind, Inc. and Skipjack Offshore Wind, LLC for a Proposed Offshore Wind Project(s) Pursuant to the Maryland Offshore Wind Energy Act of 2013, MD PSC Case No. 9431, Order No. 88192 at 1 (May 11, 2017). (also estimating that the combined 368 MW projects would result in $1.8 billion of in-
three years but can be suspended and held by the Delaware Sustainable Energy Utility.

States have opted for a range of long-term and short-term RPS program targets. Delaware and Illinois have RPS programs with a goal of 25% by 2025-2026, whereas the District of Columbia has both a 20% goal by 2020 and a 50% goal by 2032. Indiana's RPS program, in contrast, is voluntary and has a 10% target by 2025.

Penalties. States have chosen a variety of designs around penalties and alternative compliance payments for LSEs that fail to meet RPS requirements. The District of Columbia employs a diminishing penalty structure for certain resources and a general alternative compliance payment for others. Delaware has a greater penalty for solar non-compliance than non-solar non-compliance. Michigan does not enforce penalties but does require certain filings before the Public Utility Commission. North Carolina provides the Public Utility Commission flexibility to determine individual penalties.

30 Ind. Code §8-1-37.
31 D.C. Code §34-1431 et seq.
Beyond RECs, several states have enacted policies to encourage energy storage in recent years. For example, California has required its investor-owned utilities to deploy 1,325 megawatts of energy storage through a competitive procurement process by 2024.

In PJM's service territory, Maryland has implemented a tax credit encouraging residential and commercial taxpayers to install energy storage systems on their property, while New Jersey recently passed legislation requiring its Board of Public Utilities to "establish a process and mechanism" for achieving 600 megawatts of energy storage in the state by 2021 and 2,000 megawatts of energy storage by 2030.

These and other state efforts to encourage nascent energy storage technology complement the Commission's recent Order No. 841, which removed barriers to the participation of energy storage resources in wholesale markets operated by RTOs and ISOs.

Energy storage resources are not clearly targeted by PJM, as Mr. Keech's affidavit does not include them within the scope of its estimate of resources with "subsidies that would be subject to repricing." See PJM filing, Attachment E, Affidavit of Adam J. Keech on Behalf of PJM Interconnection, LLC ("Keech Affidavit") at P 18. Nevertheless, we have included them here because they are potentially swept up by the logic of PJM's proposals.


Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("Order No. 841").
Many states within PJM have also enacted policies to promote peak demand reductions and demand response. Demand response policies and programs provide a host of benefits for utilities, consumers, the local economy, and the environment.

Reducing the peak demand on the utility or broader energy system can significantly reduce total system costs and consumer bills. Over a longer time period, these investments in demand response can also reduce or delay needed investment in new or upgraded distribution and transmission infrastructure and new energy generating units.

Pennsylvania's energy efficiency and conservation standard, known as Act 129, includes an “Act 129 Demand Response Program.” Under this program, commercial, institutional, and industrial customers within many of the state’s investor-owned utility territories have the option to participate in utility-run summer demand response programs. For example, PPL offers its own DR programs through Act 129’s program. In PPL’s 9th year of the program (Summer 2017), the utility was able to reduce summer peak demand by an average of 126.7 MW over three DR events.

In a consultant’s evaluation of the program, PPL’s DR program was found to have...
"NPV Lifetime Capacity Benefits" of $6.188 billion. This was around 6-fold more than the NPV costs of PPL's DR program ($1.04 billion).

In Maryland, Baltimore Gas & Electric (BGE), Potomac Electric Power Company, Delmarva, and the Southern Maryland Electric Cooperative all offer demand response programs for both residential and non-residential customers. For example, BGE's program includes demand response programs for air conditioning, electric water heating, and multifamily housing, as well as a "PeakRewards Trade Ally" program that rewards HVAC contractors that successfully get customers to participate and maintain their enrollment in any of BGE's demand response programs. These programs are offered as part of the state's energy efficiency program, emPOWER Maryland. The demand response programs within emPOWER Maryland helped eliminate the need for more than 2 GW of new power capacity in the region. For every dollar spent on emPOWER programs, the state saw about two dollars in benefits – which include "power wholesale prices for energy, savings from reduced demand for electricity production, and reduced need to build new power plants and power lines".

D. Benefits of state policies

Experience shows that RPSs and other clean energy programs are good investment for states, creating significant benefits that easily justify their costs. For example, Delaware found that for the period between June 1, 2014 and May 31, 2015, the benefits of the state's RPS

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44 Id.
exceeded costs by over $22 million, taking into account impacts on the economy, air quality, and greenhouse gas emissions.

A 2016 study by the National Renewable Energy Laboratory ("NREL") shows an even higher cost-benefit ratio at the national level: assuming existing RPSs remain in effect until 2050 nationwide, the study found, these programs would lead to estimated costs of $31 billion, compared with environmental and health benefits of $97 billion and global climate benefits of $161 billion.

Further benefit of state policies fostering clean energy resources is that they create space for promising nascent technologies to mature. As the Commission recently noted in the electric storage context, "barriers to the participation of new technologies . . . in the RTO/ISO markets can emerge when the rules governing participation in those markets are designed for traditional resources and in effect limit the services that emerging technologies can provide."

By providing revenue for attributes and services not accounted for in the market, state policies can level the playing field between emerging clean technologies and incumbent resources advantaged by the status quo.

E. Demand for zero-emission energy is a market fundamental

State policies are also driven by a market fundamental: there is growing demand for clean energy by end-users, including large businesses who prioritize ready access to zero-emission electricity service. Nationwide studies document the phenomenon, with voluntary "grown
power" demand rising by nearly 130% from 2010 to 2016. Moreover, business continues to forge ahead with even more ambitious commitments to procure clean energy. Among Fortune 100 companies, 63% have adopted clean energy targets. Nearly two-dozen Fortune 500 companies have committed to power all of their corporate operations with 100 percent renewable energy, including Apple, Bank of America, Facebook, Google and Walmart. Businesses committed to their clean energy goals make access to zero-emissions energy a core part of their decisions on where to site expanded operations. According to the Renewable Energy Buyers Alliance, commercial and industrial buyers have contracted for about 5 GW of wind and solar power, and intend to procure an additional 60 GW by 2025. States rationally must respond to ensure the retail markets are delivering the kind of supply that is being demanded, and accordingly have developed policies that aim to overcome the significant barriers that remain to widespread commercial deployment of clean energy technologies.

II. Minimum offer price rule history in PJM

PJMs proposals would fundamentally alter the region's use of the minimum offer price rule ("MOPR"). As discussed further in Background section IV, capacity repricing would replace it, while MOPR-Ex would vastly extend it. MOPR has been in place in PJM for over a decade

This tracks only voluntary purchases, separate from those that meet compliance requirements. Such voluntary purchases comprise 27% of the U.S. renewable energy market in 2016. O'Shaughnessy et. al., "Status and Trends in the U.S. Green Power Market NREL (2016 data) at 5, available at https://www.nrel.gov/docs/fy18osti/70174.pdf


See e.g., Corporate Clean Energy Procurement Index: State Leadership & Rankings Retail Industry Leaders Association, Information Technology Industry Council & CleanEdge (2017) (providing members with rankings of states that have policies to support large business clean energy procurements).

Id. at 4.
and during that time has undergone substantial change. In 2006, FERC approved a settlement adopting tariff provisions to address market power concerns in PJM's capacity market, known as the Reliability Pricing Model ("RPM"). The 2006 tariff changes first established MOPR as a means to ensure that "net buyers do not exercise monopsony power by seeking to lower prices through self-supply."

The provisions sought to "distinguish . . . net buyers that may have incentives to depress market clearing prices below competitive levels" and those without such incentives.

The Commission approved, over protest, an exception from the MOPR for capacity built pursuant to state mandate, finding that the exemption is reasonable because it enabled states to meet their responsibility to assure local reliability.

For units that had their offers mitigated, the Commission also approved an option to adjust the default bid to account for recovery of "investment costs required to comply with government-mandated requirements (such as, for example, environmental regulations)."

On rehearing, the Commission concluded that, "[m]itigation does not, and should not, protect customers from actual capacity cost increases that may be attributable to environmental requirements or other necessary investments in order to allow that generator to participate in the capacity market."

The 2006 MOPR did not contain a categorical exemption for self-supply, but rather allowed Load Serving Entities to avoid participating in the auction altogether by allowing them to commit to procuring the full amount of their capacity needs in advance for a one-year period.

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57 Id. at P 34.
58 Id. at P 104.
59 Id. at P 106.
60 PJM Interconnection, L.L.C., 119 FERC ¶ 61,318 at P 150 (June 25, 2007) ("PJM 2007 RPM Settlement Rehearing Order").
On rehearing, the Commission explained its rationale for accepting mitigation rules that did not exempt partial self-supply which would bid as a price-taker. The Commission found that the MOPR focused on the "relevant conditions" under which sellers (as net-buyers) have the ability to depress prices and profit as a result (i.e., where mitigation is able to deter exercise of market buyer power). Under those conditions, even "small additions of capacity may reduce auction prices significantly, and yield a net profit for the buyer."

In several proceedings over the years, PJM proposed adopting a MOPR that would provide substantial discretion in determining when offers are mitigated. The Commission rejected those proposed tariff changes as not just and reasonable, concluding that, "to provide needed certainty to all participants, PJM must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule."

In the wake of complaints filed related to the market effects of state measures that were ultimately held to be preempted under the Federal Power Act, the Commission approved.

PJM 2006 RPM Settlement Order at P 36.

PJM 2007 RPM Settlement Rehearing Order at PP 167-170.

Id at P 167. The mitigation provisions in place at the time required sensitivity analysis to affirm that the self-supply bids would, in fact, have the specified effects on market clearing prices.

Id at P 170. Mitigation did not kick in unless an LSE bidding behavior would cause clearing prices to be "unreasonably low.

PJM Interconnection, L.L.C., 126 FERC ¶ 61,275 at P 190 (Mar. 26, 2009). ("PJM 2009 RPM Order"); see also PJM 2007 RPM Settlement Rehearing Order at P 180 ("objective criteria should be developed . . . so that predictable results will emerge"). In 2011, the Commission afforded PJM and the IMM jointly a greater role in reviewing whether a seller's offer is an exercise of market power, but emphasized that the new procedure did not provide discretion to "unilaterally decide whether a resource gets mitigated.


sweeping changes to the PJM MOPR rules. Among other changes, the exemption for capacity built pursuant to state mandate was eliminated, though the Fixed Resource Requirement remained in place and the Commission again rejected a separate self-supply exemption.

Notably, the Commission rejected a proposal raised in a complaint filed by generators to trigger MOPR based on whether a unit received a subsidy, explaining: "we are not persuaded that determining what constitutes a 'subsidy' or a 'discriminatory payment,' as opposed to evaluating net costs, will be a less subjective and more precise means of preventing uneconomic entry."

At the same time, the Commission approved expansion of the categories of resources that are allowed to submit zero-price offers, which already included nuclear, coal, hydroelectric, and integrated gasification combined cycle plants, to include wind and solar.

The Commission found persuasive PJM's explanation that, compared to combustion turbine or combined cycle gas plants, "wind and solar resources are a poor choice if a developer's primary purpose is to suppress capacity market prices." An entity seeking to exercise buyer market power would need to offer as much as eight times the nameplate capacity of such a gas plant to achieve the same price benefit.

In addition, the Commission agreed that the long-lead time for development of wind and solar resources provided good reason to exempt them from the MOPR. Developers of such projects would make decisions based on "several years of auctions and energy market prices" and would necessarily begin construction and incur costs years in advance of the first.

66 PJM 2011 MOPR Order.
67 Id. at PP 139, 192-196.
69 PJM 2011 MOPR Order at P 152.
70 Id. at P 153.
71 Id.
72 Id. at P 155.
By the time such a resource participates in the BRA, "the resource would most likely have tens or hundreds of millions of dollars of sunk costs" resulting in a small or even zero net avoidable incremental cost.

In upholding expansion of the MOPR on rehearing, the Commission also openly recognized that the RPM is not designed to explicitly recognize certain legitimate state objectives, such as environmental goals.

The Commission invited PJM market participants to consider how such broader objectives could be incorporated into the market design through a stakeholder process.

To date, PJM has never initiated a stakeholder process with that objective.

In 2013, the Commission again considered proposed changes to PJM's MOPR. Whereas the Commission had in 2011 rejected an exemption for self-supply resources, the Commission approved the modified version proposed by PJM because it considered the conditions PJM placed on eligibility for that exemption to be sufficient to ensure that self-supplying entities did not have an incentive to influence market-clearing prices by offering a price-taker bid.

Throughout the history of changes to the PJM MOPR, several principles have remained constant. As the Commission described to the D.C. Circuit in a case defending its rejection of several proposal changes to the MOPR, the rule was designed with a purpose "to prevent the exercise of monopsony power—that is, price suppression by utilities that offer capacity into the market but buy more capacity than they sell."

The goal is to "prevent market manipulation,"
and thus "[MOPR] is designed to identify new resources with the incentive and ability to depress auction clearing prices."

Further in aiming toward this objective, the Commission has always balanced the need for mitigation of buyer-side market power against the "risk of over-mitigation."

In addition, in considering the appropriate scope of MOPR's sweep, the Commission has frequently reiterated the importance of objective criteria that provide the certainty needed to market participants.

To date, because PJM's MOPR has been narrowly focused on resources that would have both the "incentive and ability" to benefit from exercising buyer market power, the Commission has not had to address the appropriateness of targeting such a large share of capacity in PJM that are being built for reasons other than the potential to financially gain by making an artificially low offer – an issue now presented in this proceeding. In other expansions of PJM's MOPR, the targeted manipulative behavior would be deterred by the application of MOPR, because the financial benefits sought are eliminated through mitigation of the offer. As discussed further herein, that is not the case with respect to PJM's proposals.

III. Stakeholder process

PJM makes much of its "extensive process" leading up to its filing of the two alternative proposals before the Commission in this proceeding, claiming to have "initiate[d] a discussion" on the issue nearly two years ago.

The stark truth is that the majority of stakeholders have at *40 (exemptions upheld were designed to sort out resources that lack incentives to bid their actual costs).
never been convinced that there is a problem threatening the PJM market at all, and voted convincingly in the stakeholder process to reject acting on any of the proposed capacity market reforms. Nevertheless, at every turn, PJM forged ahead with a process that appeared aimed at advancing PJM's preconceived "solution"; while stakeholders repeatedly sought to better understand some basic questions: what is the threat to the market PJM aimed to address; what data documented that problem; and what are the consequences of PJM's preferred approach?

After nearly a year in a stakeholder process that never delivered answers to those core questions, PJM told stakeholders that, regardless of the outcome of the vote, it would recommend that its capacity market repricing proposal be filed at FERC. Stakeholders overwhelmingly rejected PJM's proposed capacity market reform. In the face of a flood of stakeholder letters voicing frustration by the process and grave concerns about the proposal PJM sought to advance in circumvention of the stakeholder process, the PJM board took the highly unorthodox step of filing with FERC its own preferred proposal (repricing), alongside an alternative proposal (MOPR-Ex), as well as suggesting the adoption of a third, previously undisclosed option (a second version of MOPR – essentially punting to the Commission a choice of the best policy). PJM also indicated that further development of the proposal selected by the Commission might be needed by offering the potential for settlement proceedings to address unresolved issues, essentially leaving important elements of what it had filed ambiguous.

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Stakeholders engaged with PJM at twenty-two meetings over eight months on the subject of this proceeding through the Capacity Construct/Public Policy Senior Task Force available at http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx.

83

PJM filing at 7.
The task force was charged with evaluating the capacity construct in light of state public policy initiatives, identifying areas where the capacity construct and state actions may not be aligned, and considering modifications to the RPM that could accommodate/address both capacity market objectives and state actions.

Prior to the initiation of the stakeholder process, PJM had released its proposed approach to the topics at issue, a proposal to reform the RPM to adopt a two-tiered auction structure (what ultimately became the preferred proposal in this proceeding, the repricing proposal).

Stakeholders duly engaged on the issue presented by PJM, developing more than a half-dozen alternative proposals to better reconcile state policy action and RPM objectives. However, stakeholders became increasingly concerned by PJM's lack of engagement with some stakeholders' core concerns. Stakeholders repeatedly asked PJM to better explain and provide data to document its concerns of a threat to the market due to state actions. As the Organization of PJM States, Inc. ("OPSI") explained to the PJM Board in October, "unlike PJM's initiative to implement the Capacity Performance proposal, there has been no demonstration of facts, data, or information other than hypothetical fears supporting the concerns of the CCPPSTF."

To the contrary, PJM staff's analysis of the "Key Components" of the RPM Construct as a part of the stakeholder process showed no impact.
from the state actions reviewed.

OPSI also voiced a concern that was widely shared among stakeholders in the process – PJM had set an "accelerated timeline for filing at the FERC" that it seemed unwilling to depart from.

Indeed, the targeted November end to the stakeholder process was motivated by PJM's urgency to file proposed tariff language early enough to allow for the tariff to come into operation before the May 2018 auction, meanwhile many stakeholders felt frustrated that PJM was rushing to respond to an unsubstantiated concern.

In November, the task force took a straw poll to identify the proposal that would be moved forward for a vote at a higher-level committee, the Markets and Reliability Committee. The proposal that received the most support from stakeholders participating in the CCPPSTF (64 percent in favor) was to retain the status quo and not file any tariff revisions with the Commission.

Because PJM did not allow the status quo to be considered as a binding option, an alternate option receiving the next highest level of support was advanced (a version that would become the current MOPR-Ex proposal).

For many stakeholders that are not closely engaged in the work of the task force, the Markets and Reliability Committee presented their first opportunity to engage with a proposal that had a serious possibility of being submitted to FERC, evaluate how it would impact their interests, and decide how to vote. In the face of its incredibly low support from the stakeholders, further development of PJM's repricing proposal (such as draft tariff language to flesh out the operation of the proposal) with stakeholders ceased.

Id. at 2.

Id. at 3.

Before the Markets and Reliability Committee could vote on the proposal, PJM issued a letter stating that, regardless of the result of the next vote, PJM would be recommending to its board to move forward with filing its repricing proposal.

In votes at the Markets and Reliability Committee on January 25, 2018, stakeholders rejected both the repricing and MOPR-Ex proposals.

An outpouring of stakeholder opposition followed PJM's announcement of its intention to unilaterally proceed with its preferred proposal, though that approach had received only 21.4% of stakeholder support. A diverse set of stakeholder groups, ranging from state commissions, consumer groups, environmental organizations, industrial consumers, transmission and generation owners, submitted letters, raising concerns that the “rushed timeline in place for the CCPPSTF proceedings prevented stakeholders from adequately reviewing and refining proposals to resolve uncertainty and build consensus”; despite the many meetings, “PJM staff failed to convince the members that Capacity Repricing is a just and reasonable proposal”; maintaining the status quo “would have been a better outcome”; and that PJM had never responded to multiple requests for data or other support for its claim that action was needed.


93 See PJM, “Board Communications”, available at https://perma.cc/3SWF-KEGU.

94 Letter from Joint Consumer Coalition to Chairman Schneider, Mr. Ott, and PJM Board of Managers, “Recommendations regarding PJM’s Capacity Construct/Public Policy Senior Task Force (CCPPSTF)” at 5 (Feb. 9, 2018), available at https://perma.cc/RP2P-DD9G.


96 Letter from Public Service Commission of West Virginia to Executive Director Carmean Regarding OPSI Capacity Repricing Letter at 1 (Feb. 7, 2018), available at 20180507-5222 FERC PDF (Unofficial) 5/7/2018 4:33:02 PM 20200121-5400 FERC PDF (Unofficial) 1/21/2020 4:50:11 PM.
On February 16, PJM announced that, in light of the considerable stakeholder concern, that the question of the right path forward "should fall to the Commission as the federal policymaker not to the PJM Board."

Acknowledging that "certain elements of each proposal would benefit from further stakeholder input," PJM indicated that it would request that the Commission initiate a time-bound settlement judge proceeding. On April 9, 2018, PJM filed the proposed tariff revisions at issue in this proceeding.

IV. PJM proposal

In its filing, PJM asks that the Commission accept one of two proposed revisions to the rules governing PJM's Reliability Pricing Mechanism ("RPM") in its Open Access Transmission Tariff, commonly known as its capacity market. PJM asserts that these changes are necessary to "address supply-side state subsidies and their impact on the determination of just and reasonable prices in the PJM capacity market."

The premise of PJM's filing is that state public policies to incentivize the development or retention of certain classes of generating resources are suppressing capacity market clearing prices in a way that, in PJM's view, "adversely affects"...
incentives for new investment in the region. State renewable energy procurement mandates and zero-emission credits for nuclear facilities are PJM's primary concerns.

PJM's "preferred" proposal, known as capacity repricing, would fundamentally change how prices are set in the capacity market by determining which resources obtain capacity supply obligations in a separate run of the market optimization algorithm from the run that determines the clearing price. PJM states that this option would "accommodate" state subsidies while adjusting capacity prices in response to those policies.

Resources receiving support through state policy would still be given the opportunity to clear the auction based on their actual offer price (reflecting their rights and obligations under state law), but the clearing price paid to all resources would be determined in a second run of the algorithm in which all resources that PJM deems to have received "actionable subsidies" have their bids administratively adjusted to remove the value of the subsidy received.

PJM's alternative proposal would extend the current minimum offer price rule ("MOPR") to existing and new capacity resources of all types, while offering several unit-specific or categorical exemptions. PJM's stated objective of MOPR-Ex is to "mitigate the impact of state subsidies on wholesale prices," by adjusting offer prices for those resources before the optimization model is run to an administratively determined price floor that ignores the rights and obligations under the relevant state policies deemed to be "actionable". Under MOPR-Ex,

\[\text{\textsuperscript{101}}\text{Id. at 25-26.}\]
\[\text{\textsuperscript{102}}\text{Capacity repricing is described as "Option A" in PJM's filing.}\]
\[\text{\textsuperscript{103}}\text{PJM filing at 6.}\]
\[\text{\textsuperscript{104}}\text{Id. at 59–60.}\]
\[\text{\textsuperscript{105}}\text{MOPR-Ex is denoted as "Option B" in PJM's filing.}\]
\[\text{\textsuperscript{106}}\text{Id. at 6.}\]
such resources would only clear and earn revenues in a capacity auction in the unlikely event that
the administratively determined offer price is below the market clearing price.

PJM asks the Commission to accept one of the two proposed revisions by June 29, 2018,
or if the Commission determines that it must conduct further proceedings, by January 4, 2019.

ARGUMENT

I. To protect the market from an illusory threat, PJM would give FERC the
impossible and improper task of policing state policy

PJM exhorts the Commission that "now is the time" for urgent action.

PJM alludes to a

looming threat to reliability because of state subsidies,

but in making this claim PJM is akin to

a man neck-deep in water, shouting that drought is imminent. Nowhere in the market is there any

sign of a systematic

lack

of adequate capacity to threaten reliability, to the contrary by all

measures it is at an excess; and investor appetite to enter the market remains voracious.

Claiming

an urgent threat to entry is belied by all objective standards and is not credible.

If, on the other hand, the alleged looming threat is not to entry, but instead some longer-
term threat in the making due to a sudden upsurge in state policy action – this claim, too, is not

backed by the facts. More than half of the capacity and the vast majority of resources targeted by
PJM's proposal are supported by state laws and policies that have been on the books for

years

(in

some cases, since the capacity market's inception); only a single Illinois plant is supported by a
state policy of any recent vintage.

Indeed, national, state, and local government incentives and

107

Id. at 7–8.

108

PJM filing at 36.

109

Id. at 19.

110

PJM identified 698 MW of RPS program resources, 981 MW of demand response or
price responsive demand resources, and one 1400 MW nuclear generator.

See

PJM filing,

Keech Affidavit at P 18. We note that one additional potential state law is pending in
New Jersey at the time of this filing, which would not be accounted for in those figures.
other forms of support are pervasive in the energy sector and have shaped market participant behavior since the formation of the RPM.

If investment and decision to enter the market were materially stymied by the presence of these preferences, the capacity market today would not display the strong fundamentals that PJM hails in its filing.

Perhaps, PJM's true concern is ensuring the appropriate exit of resources in light of booming investment and capacity above reserve margins. If so, its preferred policy proposal is wholly off the mark, as capacity repricing does virtually nothing to change incentives to exit the market while MOPR-Ex affirmatively sends a signal to unnecessary resources to remain. And both proposals target policies incenting new entry, rather than focus solely on policies deterring exit of existing resources. In short, PJM proposes the rushed adoption of complex new market rules because of a "growing threat" that is wholly imagined.

In response to an illusory crisis, PJM would make FERC the policeman of the countless policies that potentially affect the competitive markets. PJM's alternate new market constructs are each based on a highly subjective determination of the scope of a "subsidy," which would thrust the Commission into the impossible role of arbitrating which among the ubiquitous forms of federal, state, and local preferences that shape market behavior must be unwound from the wholesale market in order to protect "competition." The standards offered by PJM to achieve this...

We also cannot account for whether any state laws supporting the state demand side resources are recent, because PJM has provided no explanation of what these resources are or why they are targeted.

objective lack internal consistency and economic rigor, and do not provide any objective, limiting principle to constrain an otherwise monumental task. Once the camel's nose is under the tent, the Commission will find itself far afield from its core competencies, policing all manner of government interventions (e.g., targeted federal grants for carbon capture and storage or regional natural gas infrastructure; state tax incentives for coal production; and local incentives that do not flow through economic development authorities) that affect market participant behavior and could impact market outcomes. Moreover, because the governmental entities providing these incentives are as a rule aiming to advance their constituents interests and not reap financial advantage in the wholesale markets, PJM's new market constructs would do little to deter these activities and could instead force policymakers to shift to less transparent (and correspondingly less economically efficient) means to achieve their policy objectives. At the same time, the Commission's unprecedented role in deciding how much and which kinds of government intervention go too far will amplify conflict between the states and retail authorities that have voluntarily joined the deregulated markets, heightening the tensions that already exist given the shared federal and state responsibility for the inextricably intertwined electricity system. In the end, the complex and unnecessary new market rules PJM proposes do nothing to benefit competition in the markets (indeed, as we show in section III, these new rules would harm market outcomes) and would put the Commission in a role Congress never intended.

The following section dissects each of PJM's purported claims that urgent action is needed, and finds each unsupported. The subsequent section goes on to examine how PJM's...
proposals inappropriately place the Commission in a role beyond that envisaged by the Federal Power Act, forcing unproductive and unnecessary conflict with the states.

A. PJM is wrong that competitive markets are under threat

PJM alludes to a series of potential threats to the market that warrant the Commission's urgent intervention: (1) the RPM will fail "to produce the needed investment to serve load and reliability" if some supply bids "noncompetitively"; (2) "programs which target large-scale, unit specific resources represent a serious escalation in the status quo"; and (3) the targeted subsidies adversely affect other market participants. But there is simply no evidence that investment in PJM is lacking, reliability is threatened, that the impacts of government preferences on the wholesale market now are larger than ever before; or that the programs targeted have any different or more harmful impacts than policies that have long affected the markets. As scholars at the Institute for Policy Integrity summed up their own assessment, "[t]here is no credible evidence that externality payments [the policies targeted by PJM] threaten the viability of markets."

1. PJM faces no conceivable threat to reliability

PJM states that "a market that does not fairly value the costs of meeting reliability needs will not continue to commit the resources needed for adequacy that compete only on their true net costs." However, PJM could not conceivably substantiate a claim that PJM's market faces any foreseeable threat to resource adequacy, and does not try to do so. Objective standards of the
market's performance simply would not support such an assertion. PJM's vague suggestion that the state programs targeted by PJM may, one day, impact the market's reliability is laden with unanalyzed assumptions and, even if it were not fundamentally flawed from an analytical perspective, as described in section III.94I.CC, would amount to little more than rife speculation.

The idea that market prices are too low to support new entry is defied by the tremendous amount of new build entering PJM in spite of already high reserve margins. PJM's latest planning reserve margin for the summer of 2018 is 28.7 percent. This is significantly higher than PJM Staff's recommended installed reserve margin target of between 15.8 and 16.1 for delivery years 2018/2019 through 2021/2022.

Further, when looking forward at expected power builds and retirements, there appears to be no risk of a capacity shortfall in the next few years. As shown in Figure 1, there are over 20 GW of new natural gas capacity under construction or in advanced development expected to enter operation by the end of 2021. An additional 18 GW of natural gas capacity has been announced or is in early development. At the same time, only 7.4 GW of fossil and nuclear capacity have announced and approved retirement dates between now and 2021, according to

PJM offers only conditional and evasive assertions of an actual threat to reliability. See e.g., id. at 38 (“PJM's continuing ability to deploy market forces to efficiently and reliably handle a changing resource mix may be threatened if the promotion of other policy interests are pursued in a way that materially distorts price outcomes in PJM's capacity and energy markets.”) (emphasis added).


By 2021, PJM could see a net addition of up to 40 GW, even as load is expected to see relatively little growth over the same timeframe.

Figure 1: New Capacity in PJM (MW)

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
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<tr>
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<td>1,707.6</td>
<td>118.0</td>
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Cumulative Net Capacity Change (High)

|                      | 10,420.5 | 16,126.8 | 30,045.0 | 40,125.5 | 41,142.3 | 41,228.3  |

Cumulative Net Capacity Change (Low)

|                      | 7,081.7  | 7,236.4  | 12,515.5 | 15,177.5 | 15,188.4 | 15,222.4  |

Source: S&P Global Market Intelligence. *When a unit development is publicly announced, S&P MI initiates coverage. Future units listed only in an interconnect queue are not considered; some additional public announcement or permitting action must be taken to initiate coverage. A project is updated to early development when the permitting process begins. A project is moved to advanced development when two of following five criteria has been achieved: financing in place, power purchase agreement signed, turbines secured, required permits approved, or contractors signed on to the project. A project is updated to construction began when construction of the units begins; site preparations are not under construction.
likely to earn a targeted rate of return on new generation. This was more than double the next highest polling region (20 percent). As PJM itself stated in the Resource Investment Whitepaper cited in its filing, “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.”

PJM succeeded at attracting substantial investment at the same time its member states have pursued their own policies to incentivize certain types of generation. Indeed, while PJM states in its filing that “[a] part-subsidized/part-competitive market is thus a very poor design choice for the critical function of ensuring reliability,” PJM has successfully run a “hybrid” market for decades without any reliability crisis. PJM became the first fully-functioning U.S. independent system operator and then regional transmission organization in 1997 and 2002, respectively.

By that time, member utilities in New Jersey were already complying with state policies including renewable or alternative energy standards and energy efficiency resource standards. As additional utility territories were added into PJM’s footprint over the next three years, Delaware, Pennsylvania, Maryland, and the District of Columbia also implemented new state policies supporting the development of renewable and other resources.

By the end of the decade, 10 states within the PJM territory had adopted state policies promoting and/or mandating renewable energy. Watson, supra n. 121. Id. PJM Resource Investment Paper at 24. PJM filing at 34. PJM, PJM History, available at https://perma.cc/N3G8-GSKB. See Galen Barbose, Lawrence Berkeley National Laboratory, U.S. Renewables Portfolio Standards, 2017 Annual Status Report at 8, available at rps.lbl.gov. PJM History, supra n. 129. See Appendix A.
Three states were also members of a regional carbon market.

As shown in Figure 2 below, despite this concurrent growth of PJM's footprint and state energy policies since the early 2000s, the region was routinely able to attract new capacity under both the current RPM design and earlier market structures.

Figure 2: Capacity Additions and Retirements in PJM Region

There is also little evidence that state policies supporting renewable energy development have had or are having a measurable impact on market prices or investor confidence. The largest source of new builds, both historically and the near-term future, are natural gas facilities. As shown in Figure 3, around 95 percent of all projects identified by S&P Global Market Intelligence, Power Plant Units Database and Screener Tool, Subscription required, available at https://www.spglobal.com/marketintelligence/en/.
Intelligence as under construction or in advanced development within the PJM footprint are natural gas projects. Just five percent are wind and solar energy. Even when accounting for all stages of development, wind and solar projects represent just a quarter of all projects in S&P's tracking database.

Policy preferences have always affected market prices. PJM claims that while one must "accept a tradeoff between perfect competition and interventions that affect price outcomes for the benefit of some at the expense of others," recent policy actions represent a "serious escalation" in the status quo.

PJM points to the "emergence of multiple specific, substantial state subsidy programs that," in its view, "could have a material price suppression effect in the wholesale capacity market.

Yet it offers no evidence that the policy actions it targets are, by any measure, more impactful or concerning than the pervasive policy choices by governments at all levels that have affected PJM market prices throughout its

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<table>
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<tr>
<th>Fuel Type</th>
<th>Operating</th>
<th>Under Construction</th>
<th>Advanced Development</th>
<th>Early Development</th>
<th>Announced</th>
<th>Mothballed</th>
<th>Out of Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass &amp; Waste Energy</td>
<td>2,148.7</td>
<td>-</td>
<td>-</td>
<td>11.2</td>
<td>104.4</td>
<td>-</td>
<td>10.2</td>
</tr>
<tr>
<td>Coal</td>
<td>64,351.9</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>12.5</td>
</tr>
<tr>
<td>Gas</td>
<td>87,994.4</td>
<td>15,424.1</td>
<td>5,231.2</td>
<td>18,628.4</td>
<td>1,458.5</td>
<td>110.6</td>
<td>58.4</td>
</tr>
<tr>
<td>Oil &amp; Other Non-Renewables</td>
<td>8,767.4</td>
<td>20.0</td>
<td>175.0</td>
<td>44.0</td>
<td>18.5</td>
<td>-</td>
<td>31.8</td>
</tr>
<tr>
<td>Nuclear</td>
<td>35,785.1</td>
<td>-</td>
<td>1,600.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>153.8</td>
</tr>
<tr>
<td>Water</td>
<td>8,369.0</td>
<td>-</td>
<td>96.3</td>
<td>389.3</td>
<td>5,505.3</td>
<td>-</td>
<td>15.9</td>
</tr>
<tr>
<td>Wind</td>
<td>8,036.9</td>
<td>565.6</td>
<td>647.7</td>
<td>9,211.5</td>
<td>3,136.0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Solar</td>
<td>2,315.2</td>
<td>301.6</td>
<td>437.1</td>
<td>3,105.2</td>
<td>200.9</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>217,768.6</td>
<td>16,311.3</td>
<td>6,587.3</td>
<td>32,989.6</td>
<td>10,423.6</td>
<td>110.6</td>
<td>128.8</td>
</tr>
</tbody>
</table>

Source: S&P Global Market Intelligence. When a unit development is publicly announced, S&P MI initiates coverage. A project is updated to early development when the permitting process begins. A project is moved to advanced development when two or following five criteria has been achieved: financing in place, power purchase agreement signed, turbines secured, required permits approved, or contractor signed on to the project. A project is updated to construction begun when construction of the units begins; site preparations are not under construction.
Indeed, it is not at all clear what manner or scale of "subsidy" PJM believes has the greatest impact on market prices. PJM suggests that it is "programs which target large-scale, unit specific resources" that present a new threat, but PJM does not explain why that is so.

Nor does PJM focus its proposals on such programs. Instead, more than half of the capacity targeted by PJM's proposals are renewable, demand response, and price responsive demand resources, which are by their nature typically not "large-scale" resources, and comprise a small percentage of the resource base in PJM.

Historical data demonstrates that government policies have provided substantial support targeted toward specific types of capacity resources, including large-scale ones that comprise a significant share of capacity in the PJM market. There is no reason to believe that historic policy actions would have any less impact on market prices than PJM contends they do today. In 1989 alone, for example, coal-fired generators benefited from nearly seven and a half billion dollars in federal government support, and natural gas fired generators a little less than one billion.

On average, federal subsidies to conventional generation amount to roughly eleven percent of

138 Subsidy is a subjective term that imputes a value judgment. The term implies a government transfer of value (directly or indirectly) that would otherwise have had to be purchased in marketplace. The term should not be applied to state policies that address well-documented market failures. The state policies targeted by PJM largely address the externalities imposed by climate change, for which there are objective estimates of the public value. The Interagency Working Group on Social Cost of Greenhouse Gases estimated the social cost of carbon to be roughly $50 per ton in 2010 (in 2007 dollars and using a 2.5% discount rate).

139 PJM filing at 15.


141 Including nuclear, hydro, coal, gas, and oil.
It defies reason to suggest that support of this magnitude did not affect the composition of capacity resources, providing advantages to some resources and not others, and affecting wholesale prices. Indeed, subsidy expert Koplow concludes that historic subsidies that have underwritten long-lived capital investments would have "the same type of market effect as current subsidies."

The same basic principle would apply, "regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted."

And while renewables are "late entrants" to the scene, incumbent generators have received many large state tax breaks that are documented as far back as the 1950s, 60s, and 70s.

3. The positive spillover effects of state policies on other states do not justify tariff revisions to insulate the PJM capacity market from those effects.

PJM argues that urgent intervention into the markets is warranted because "the effects of state subsidies to sellers that offer into PJM markets are not confined to the State."

This logic is flawed because it could be used to justify action to adjust for any type of state regulation, transforming the Commission's role from its narrow oversight of wholesale sales of electric energy as a shared regulator of the electric sector into an agency responsible for addressing labor practices, environmental regulation, and much more. Furthermore, PJM's rationale makes no sense because state policies providing additional compensation to generators benefit rather than harm customers in other states.

Id. at 20.

Koplow report at 1.

Id. at 4.

Id. at 17. Federal tax breaks for conventional energy go back even earlier in the history of the energy sector.

PJM filing at 29 (altered to lowercase from the original heading title).
Under PJM's theory that subsidized entry lowers market clearing prices, one state's policy providing compensation to a generator essentially provides customers in other states with lower-cost, subsidized capacity.

It is hard to see how lowering the cost of supply for customers in other states is a hardship for them.

Further, while the dynamic price effects are less certain, the very clear consequence of state climate policies is to positively impact all customers by reducing harmful emissions.

Indeed, by PJM's logic, it would have a more powerful case for adjusting prices in response to state policies setting pollution standards, or adopting emissions-based taxes or fees.

According to PJM's reasoning, such taxes and regulations would have the natural effect of raising capacity prices for all customers in the region in the near-term, because generators emitting the harmful pollution would need to factor the cost of purchasing allowances into their offer prices, pushing the clearing price higher.

The case for spillover to other state customers would be far clearer, because other states would pay higher prices. Yet no one has ever...
understood this to empower grid operators to impose and the Commission to approve measures that insulate the market from the effects of those policies by adjusting downward the offer prices of affected generators. Were the Commission permitted to reverse state environmental taxes or fees in this manner, its role would transform into that of an environmental regulator because it could pick and choose when to effectively reverse those state environmental policies by making adjustments to its power markets in direct response to them.

Nor would either of PJM's proposals lessen any conflict between states that could be caused by the inevitable spillover effects that any policy will have. PJM's proposals both harm all customers in the entire applicable capacity zone as a direct consequence of one state's policy adoption and in proportion to the amount of MW supported by that state. PJM rules thus creates a far worse spillover concern, thereby increasing rather than decreasing the potential friction between them. As discussed in section I.B below, PJM's proposals, and particularly the MOPR-Ex proposal, would likewise thrust PJM and the Commission into an environmental policymaking role.

While PJM argues that state policies supporting generation could raise total costs in the long run, even if that were true, customers in the states enacting the policies at issue would be the ones to shoulder the burden while customers in other states would come out ahead (not having to cover the costs of the state program). Further, if true, PJM's prediction of eventual cost increases destroys its case that the market structure creates misaligned incentives by which states can enact subsidies because the costs are "underwritten by other participants in the wholesale..."
Rather, under PJM's theory, states would only enact programs when their benefits outweigh these long run costs, and there would be no need for the Commission to step in. PJM has presented no analysis or economic theory indicating that customers in other states would be harmed under the status quo operation of its markets. If PJM is arguing for the Commission to "protect" a state's customers from that state's policies, that makes little sense. State policymakers, not the Commission, are in the best position to decide whether the benefits of clean energy warrant any costs those policies may impose on state customers.

4. Even assuming there were a threat, PJM's proposals do not aim at the actions allegedly causing it. PJM's articulated fear is that "owners of these legacy assets" may "seek out-of-market support from states to forestall retirement and defeat the design objective of PJM's market, at the expense of their competitors and wholesale consumers." Likewise, the Independent Market Monitor seeks to prevent the spread of "subsidies . . . requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units" rather than "to accomplish broader social goals."

Even assuming, arguendo, the potential spread of unit-specific subsidies warranted the high costs of intervening in the market and overturning states' legitimate role, it is clear that PJM's goal could be accomplished through a far narrower measure adjusting only for the effect of subsidies targeting specific existing units that have become uneconomical under the bargain by which they were built. Yet the options presented by PJM leave states free to develop unit-specific subsidies.

As explained in section III.C.3.a.i, PJM's claim, even if it were true, would provide no legal basis for its proposals under the Federal Power Act.
specific subsidies, through "county-specific" measures or through programs couched as industrial development initiatives. Instead, PJM primarily targets state climate policies, whether or not they focus on particular existing units. Both of PJM's proposals target the vast majority of state policies designed to spur the construction of new renewable resources. Programs such as the offshore wind mandates in several states are clearly intended "to accomplish broader social goals" and are not an example of rent-seeking by owners of units that have become uncompetitive. Moreover, the majority of state programs designed to spur renewables are competitive, awarding credits to the developers of new resources rather than to particular units seeking a handout for reasons unrelated to environmental objectives.

In sum, PJM fails utterly to back its claims of crisis. But even if it had done so, PJM's proposals are entirely misaligned to resolve the threats to the market it alleges are looming on the horizon.

B. PJM wrongly puts the Commission in the position of policing the efficiency of state policies. PJM presents states with a stark choice: rely on competitive markets, or retain full policymaking authority, but not both. In doing so, it misunderstands the structure of the Federal Power Act and the history of state restructuring. PJM would thrust itself, the Independent Market Monitor, and ultimately the Commission into an environmental policymaking role that each is ill suited to play. MOPR-Ex's intrusion into the state policy-making sphere is blatant and extreme. While PJM's capacity repricing proposal is more accommodative of state choices, it would nonetheless impose a penalty on states for enacting certain policies to regulate generation mix.

157 See supra section I (describing state policies).

158 Setting aside the different question of whether these programs would meet the overly-restrictive eligibility requirements of the MOPR-Ex RPS exemption.
but not others, prodding them to design potentially less efficient policies that do not meet the definition of "actionable subsidies" and raising the specter of further intervention in the future.

In forcing states between a rock and a hard place in this manner, PJM invites the Commission to undermine the very principle of encouraging competition that PJM purports to cherish. Such tactics surely are not the way to encourage more utilities and states to join organized wholesale markets, or to entice currently vertically integrated states to join the competitive market paradigm. While states have greatly benefited from the Commission's competitive markets, their policymaking authority is even more fundamental. With the impacts of climate change already harming states citizens and prognostications of the future without urgent policy response growing increasingly more dire, states' push toward clean energy is inexorable. Ignoring that demand fundamentals are moving the future of the energy sector toward zero emissions energy only risks making a capacity market that resists those forces irrelevant, or worse, detrimental to proper market functioning.

PJM's proposals would greatly reduce the appeal of its markets while harming customers in the process. Rather than accepting PJM's invitation to stoke tension between wholesale and retail objectives in this manner, the Commission should instead reject both proposals and focus on market reforms that enhance efficiency while facilitating state choices.

1. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix. PJM argues that "the fully restructured states in the PJM region elected to rely on competitive markets as the means to select resources needed to serve loads." That argument is wrong as a matter of fact, and misunderstands the respective roles of the Commission and states.
under the Federal Power Act. In restructuring, states contemplated that competition rather than integrated resource planning would ultimately determine the mix of resources. But, consistent with the structure of the Federal Power Act, states understood that such competition would be influenced by state policy, including environmental and clean energy policies such as renewable portfolio standards. States did not give up their ability to influence market outcomes through environmental policy decisions, nor did the Commission or the courts interpret them as having done so. Short of amending the text of the Federal Power Act, it would be impossible for states to give up their authority and responsibility to shape the resource mix, even if they wanted to. Nor is it lawful for the Commission to attempt to reverse state environmental policies where a state has not exceeded its authority under the Federal Power Act.

In declaring that state restructuring legislation dictated that PJM’s markets would be the sole determiner of resource mix, PJM cites the decisions of four states as evidence: Illinois, Maryland, New Jersey, and Ohio. Yet every single one of these states has had a renewable portfolio standard for roughly a decade or more. Two of the states, New Jersey and Ohio, adopted renewable portfolio standards in tandem with or as part of restructuring legislation, making abundantly clear that they were not ceding any authority over resource mix as part of their decision to restructure. The following table demonstrates that RPS are the norm among states that have pursued restructuring, both within and outside of PJM.
### Figure 4: RPS and Restructuring Summary

<table>
<thead>
<tr>
<th>State</th>
<th>RPS + Restructuring Context</th>
<th>Established</th>
<th>2020 Goal</th>
<th>2025 Goal</th>
<th>2030 Goal</th>
<th>2035 Goal</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>Established in tandem with restructuring (1998), applies to utilities and retail suppliers; 28% by 2020; requires utilities enter long-term contracts (15 years)</td>
<td>1998</td>
<td>2020</td>
<td>2025</td>
<td>2030</td>
<td>2035</td>
</tr>
<tr>
<td>DE</td>
<td>Established in 2005, applies to utilities and retail suppliers; 25% by 2025.</td>
<td>2005</td>
<td>2020</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>IL</td>
<td>Established in 2007 as part of restructuring reform legislation that created the Illinois Power Agency (IPA) which procures power for default service; 25% by 2025 for both utilities and retail suppliers.</td>
<td>2007</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>ME</td>
<td>Established as part of initial restructuring legislation; 40% by 2017, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2017</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>MD</td>
<td>Established in 2005; 25% by 2020, applied to all utilities and retail suppliers.</td>
<td>2005</td>
<td>2020</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>MA</td>
<td>Established as part of initial restructuring legislation; 15% by 2020, with 1% each year thereafter, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2020</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>NH</td>
<td>Established in 2007; 25.2% by 2025, applies to both utilities and retail suppliers.</td>
<td>2007</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>NJ</td>
<td>Established in tandem with restructuring (1999); 50% by 2030, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2030</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>NV</td>
<td>Established as part of its 1997 restructuring legislation (restructuring indefinitely halted in early 2000s); 25% by 2020.</td>
<td>1997</td>
<td>2020</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>NY</td>
<td>Established 2004; 50% by 2030, applies to all utilities and retail suppliers</td>
<td>2004</td>
<td>2030</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>OH</td>
<td>Established in 2008 as part of broad restructuring reform legislation; 12.5% by 2026, applies to both utilities and retail suppliers.</td>
<td>2008</td>
<td>2026</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>PA</td>
<td>Established in 2004; 18% alternative energy, applies to both utilities and retail suppliers.</td>
<td>2004</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>RI</td>
<td>Established in 2004; 38.5% by 2035, applies to both utilities and retail suppliers.</td>
<td>2004</td>
<td>2035</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>TX</td>
<td>Established during restructuring transition (1999); 10 GW of RE capacity by 2025.</td>
<td>1999</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
<tr>
<td>DC</td>
<td>Established in 2005; 50% by 2032, applies to both utilities and retail suppliers.</td>
<td>2005</td>
<td>2032</td>
<td>2025</td>
<td>2025</td>
<td>2025</td>
</tr>
</tbody>
</table>

The history of these state laws, which is consistent with that of many other states in other regions across the country, makes clear that the competition states had in mind was a framework where resource mix was determined not only by competition to sell electric energy, but also through competition to sell credits representing environmental benefits associated with power production from certain types of resources. Indeed, the restructuring boom of the 1990s coincided directly with the adoption of many state renewable portfolio standards across the country, as shown in the chart below:

**Figure 5: Historical Progression of RPS and Restructuring**

- **Recently Adopted RPS**: CO, HI, MD, NY, RI (2004); DC, DE, MT (2005)
- **Recently Revised RPS**: CA, NJ, NM, PA (2004); CT, NV, TX (2005); WI, NJ (2006)
In this process, states clearly retained the power to determine the types of resources eligible to serve load: Renewable portfolio standard legislation specifically dictates that a specific percentage of the resource mix in each year shall be composed of renewable resources. States, not the Commission, would dictate the terms of the competition to sell environmental benefits, including defining what constitutes "renewable", specifying whether specific types of resources would get any additional bonuses or carve-outs, and determining whether competition would be open to all resources of that type or only to new construction.

This history belies PJM's suggestion that reliance on wholesale market competition to determine resource mix is an all-or-nothing proposition. Judicial precedent affirming the Commission's authority over capacity markets confirms that states retained full authority to dictate the resource mix, including through decisions as granular as regulations designed to determine the viability of particular power plants:

State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission."

The structure of the capacity markets thereby explicitly contemplated that the Commission would merely set a reserve margin to be met through competition as influenced by state environmental and other policies, including actions as drastic as forbidding the construction of a specific unit.

See supra Background Section I.A. Connecticut Dep't of Pub. Util. Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009). These rights retained by states and municipal authorities are meaningless if FERC can ignore or block market access for resources preferred by states even where states are not exceeding their authority under the Federal Power Act.
Finally, it is axiomatic that what can be accomplished through state regulation can be undone through state regulation. Even if true that actions by Illinois and other states were a retrenchment toward a regulatory paradigm closer to traditional cost-of-service ratemaking, the states have full authority to reverse course. Indeed, the legislation establishing the Illinois Power Authority which procures power for default electricity service for Illinois customers has been cited as a step towards "re-regulation" in state commission reports.

2. PJM, by deeming legitimate state policies that aim to address market failures as pernicious "subsidies," places wholesale market rules on a collision course with states' core duty to protect the public. PJM frames its proposed options as means to deter states from adopting policies to affect the electricity generation mix, suggesting a goal of the market construct should be to ensure competing resources are not "crowded out" by state-sponsored resources.

But if the Commission acts to prevent state environmental policies from allowing cleaner resources to "crowd out" other highly polluting generators, that would frustrate states in carrying out their core duties to protect the public from pollution. The very purpose of state policies, of course, is to induce fewer emissions and environmental impacts by replacing dirtier energy supply with cleaner sources. While PJM essentially admits that its proposals "countermand" state policies, the Commission cannot properly approve a proposal whose purpose is to do so. State policies address serious problems facing state citizens, including severe health impacts, increased...
mortality, and other harmful effects caused by some types of power plants and avoided by others.

The MOPR-Ex proposal, in particular, is a direct attack on state policies because it does not have merely incidental effects upon the achievement of those policies, but rather aims to undo them.

Unlike other state subsidy programs that PJM has sought to neutralize through application of MOPR in the past, the policies targeted by PJM's proposals are fully within state authority and not preempted by the Federal Power Act.

The state policies at issue do not aim to adjust energy or capacity prices, but rather aim to address externalities caused by power production. By mitigating resources supported by state policies, PJM's MOPR-Ex proposal would have the Commission second-guess and reverse state policy determinations about the value of externalities. This is fundamentally beyond its competence and statutory role, and would transform the Commission into an environmental regulator, setting the stage for a future Commission to judge and mitigate for states' failure to regulate externalities.

Because, as even PJM acknowledges "[s]ubsidies 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."

Indeed, "[d]efining a subsidy to include all government interventions leaves out an important category: It does not include the externalities associated..."
Thus, once the Commission has taken on the role of second-guessing the values states place on addressing an externality, it is a short step to recognizing that failure to act on such externalities, too, produces an uneven playing field. MOPR-Ex frustrates state policies by ignoring the capacity provided by cleaner resources whose viability depends on sales of their environmental benefits. Ignoring the contributions of state-supported resources forces state customers to rely on capacity from resources that do not earn revenue from state policies, essentially requiring state customers to procure a fixed amount of capacity from natural gas and coal-fired power plants. Reversing the state's choice of generation mix in this manner “necessarily affects” the “construction” or retention of particular types of resources (those not receiving revenues pursuant to state policies targeted by PJM), and is exactly the sort of “direct regulation of generation facilities” that the U.S. Court of Appeals for the D.C. Circuit stated the Commission would not engage in when approving the Commission's authority to create capacity markets. The manner in which MOPR-Ex would inappropriately strong-arm states to modify their environmental regulations is illustrated by the proposal's clumsy “RPS Exemption,” which imposes a raft of restrictive requirements on state programs in order for revenues under those policies to be permitted to influence outcomes in the PJM capacity market. In practice, the RPS Exemption would coerce states into adopting programs that comply with the conditions necessary to qualify for the exemption. The criteria of PJM's proposed RPS exemption are expansive, and many of them lie at the heart of state environmental policy decisions. The exemption appears not to include state...
policies that target particular resource types such as offshore wind, as well as state policies that differentiate between new and existing resources. At the same time, it dictates specific terms by which competition for renewable energy certificates must occur for RPS programs to be eligible. In doing so, PJM would effectively regulate the sales of RECs, despite the Commission's clear statement that the sales of unbundled credits lies beyond the Commission's jurisdiction. Defining what resource types are "renewable", for example, is a core environmental policy decision states face in designing renewable portfolio standards. Different resources have different types of benefits that states may want to encourage. Consistent with their environmental policymaking authority, states need not classify resources as either "renewable" or not "renewable" in a binary fashion. Indeed, many states have adopted resource-specific carve outs as part of broader renewable portfolio standard policies, a policy decision that appears to be frustrated under PJM's MOPR-Ex proposal.

Footnotes:

177 Id.
178 Id. at 5.14(h)(10)(b)(iii)-(iv).
179 The Commission holds that "an unbundled REC transaction that is independent of a wholesale electric energy transaction does not fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA." WSPP Inc., 139 FERC ¶ 61061 at P 24 (Apr. 20, 2012). An "unbundled REC transaction does not affect wholesale electricity rates, and the charge for the unbundled RECs is not a charge in connection with a wholesale sale of electricity." Id.
180 See supra Background section I.A.
181 See id. (describing the state policies at issue); infra Appendix A (explaining how this policy option appears to be frustrated by MOPR-Ex).
Indeed, even with regard to the narrower environmental objective of regulating carbon emissions, PJM recognizes that its "theoretical ideal market approach" of an "objective embedded in the wholesale market clearing mechanism" may be practically impossible to achieve given the "daunting number of practical, legal, and political obstacles" such an approach would face.

Regulating emissions is a complicated business. States must control for leakage, potential resource shuffling, and other issues. Deciding whether to credit only new or both new and existing resources is part and parcel of this decision, as states face a tradeoff between ensuring that sales of the credit cause additional emission reductions beyond the status quo, and the ability to foster a liquid market for credits.

While the Commission can certainly approve of RTO rules that facilitate state policy approaches to addressing this complex array of issues in an

182 PJM filing at 54-55.
183 See James Bushnell et al., Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction, 23 R EV. E NVTL. E CON'. & POL'Y 175 (2008) (reviewing various policy considerations that go into crafting state and local environmental regulations to address climate change); see also Docket No. EL13-62-002, Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc., Answer of Exelon Corporation to Request for Expedited Action, Declaration of Robert Willing at P 24 (Jan. 24, 2017) (noting that difficulties of implementing a carbon tax for a small jurisdiction include "leakage, wherein high-emitting in-state resources impacted by the tax shift their facilities out-of-state, and reshuffling, wherein high emitting out-of-state resources not impacted by the tax in adjacent geographic regions substitute for taxed in-state generation resources").
184 States may opt to credit existing and new resources or only new resources based on their determination of what will drive additional emissions reductions at least cost. See, e.g., N.Y. Pub. Serv. Comm'n, Case 15-E-0302, Order Adopting a Clean Energy Standard, at 14-17, 78, 115-16 (Aug. 1, 2016) (providing separate crediting mechanisms for existing and new resources based on cost considerations, additionality, and other factors), available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b44C5D5B8-14C3-4F32-8399-F5487D6D8FE8%7d
A regulation targeting new resources has the advantage that it is tied to measurable progress to reduce emissions. As Bushnell explains with regard to the analogous low-carbon fuel standard, which like a more indirect credit for all renewables, would "have no impact" if the amount of demand set by the state "is less than the existing supply" of the underlying product. Bushnell et al., at 184.
efficient manner, it may not frustrate state policy approaches by essentially making decisions about these tradeoffs itself. Applying a MOPR that blocks capacity market sales from resources supported by a state RPS program where that policy draws a distinction between existing and new resources is exactly the sort of second-guessing of state regulators' environmental policy decisions that is beyond the Commission's proper role.

MOPR-Ex's many arbitrary carve-outs and exemptions likewise illustrate the unworkable and inappropriate nature of allowing RTOs to pick and choose which resources may fulfill the region's capacity obligations. Unlike the unelected officials at PJM and the Independent Market Monitor, who are accountable only to the PJM market participants, state policymakers can be voted out of office if their residents conclude that RPS programs or other environmental policies are poorly designed.

C. PJM's short-sighted contention that state policies threaten its capacity market paradoxically sets the market on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed. PJM's mistaken focus on the supposedly "adverse" effects of state policies ignores the real challenge facing the capacity market: its structure is ill suited to facilitating the types of resources that states want and need. PJM's approach will lead to increased conflict and uncertainty over time. Focusing on market revisions that facilitate rather than frustrate state policy choices will yield more efficient outcomes. Rather than seeking to neutralize state policy choices, PJM should examine capacity market revisions, such as a seasonal market construct, that make the market more compatible with state policies.

Adopting either of PJM's proposed options will create more uncertainty and conflict over time because PJM's focus on potential "price-suppressive effect" provides no principled limit to the scope of Commission intervention. As states continue to adopt policies affecting the...
generation mix, the unworkability of PJM's proposed response will only grow. For capacity repricing, the counterfactual scenario of what prices would be without state policies will become increasingly extreme, imposing larger and larger unnecessary costs upon consumers over time. For MOPR-Ex, the amount of redundant capacity supported by customers year after year will continue to increase. Eventually, the unnecessary costs imposed upon customers will become untenable and a massive course correction will be necessary. The inevitable unworkability of this framework will thus cause greater uncertainty than the purported problem PJM aims to cure. MOPR-Ex could yield particularly inefficient policy outcomes because in addition to increasing redundant capacity, mitigation of state policies would likely push states to achieve their goals through less efficient policy solutions. RPS programs and zero emissions credit policies are transparent in their aim to price environmental benefits. RPS programs, in particular, rely on competitive procurement, ensuring that climate goals are met through relatively transparent and efficient means. Were MOPR-Ex to be adopted, states could avoid mitigation by adopting less transparent and less efficient policies, relying more on siting, tax code, and other policy levers. Neither the market nor the public interests would be served should states be forced to rely on a narrower band of market interventions to achieve the same results. By contrast, capacity market revisions or other actions taken by the Commission could reduce the need for state intervention in the market, increasing market efficiency. For example, as a Brattle Group report explained, “the current PJM capacity market design maintains several shortcomings that limit the full participation of seasonal capacity resources to more cost-effectively meet seasonal reliability needs.” As much as 6000 MW of summer-only supply may and to the extent that capacity repricing or MOPR-Ex deter states from enacting policies that are within their authority, that would be an inappropriate role for PJM to play. See supra Argument section I.B.
be excluded from the market, due to barriers caused by the market construct. Indeed, even as planned solar installations have grown in the region, solar offers decreased 63 percent between the last two auctions (2019/20 BRA and 2020/21 BRA), starkly demonstrating how market design can deter participation.

More generally, while PJM's markets have facilitated the construction of a large number of new natural gas turbines, they provide a bad fit for other types of resources. Because gas resources are frequently marginal in the energy market, over the long-term energy prices are correlated with gas prices. This provides a natural price hedge for gas resources, while other fuel-based resources are subjected to much higher risk.

Resources that have relatively higher upfront capital costs and no fuel costs receive no hedge at all and are forced to procure hedges to insulate against fluctuations in the price of gas.

Further, PJM's capacity market demand curves are set based on a generic natural gas unit, meaning that net CONE is pegged to the amount of revenues necessary to induce natural gas plant construction, not construction of resources of other technology types. Importantly, the advantages gas resources enjoy—a price hedge and capacity market revenue specifically designed to cover the amount of upfront capital needed to

186 See Guo et al., The natural hedge of a gas-fired power plant (Feb. 20, 2014), available at https://link.springer.com/content/pdf/10.1007/s10287-014-0222-x.pdf. Gas resources' natural price hedge is demonstrated through an examination of the 'spark', 'dark' and 'quark' spreads in PJM, which show the differences between market prices and the cost of gas, coal, and nuclear fuel, respectively. The market monitor's 2017 State of the Market report shows much higher volatility year-to-year for quark and dark spreads than the amount of volatility year-to-year in the spark spread.


PJM itself acknowledges the challenge of longer term hedging in the RPM, explaining, "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." Resource Investment Whitepaper at 28.
construct—are due to PJM’s market structure, not an inherent benefit of the resource. All else equal, customers would prefer price certainty provided by resources that do not rely on fuel. Short-term marginal cost-based markets shift the risk of changing fuel prices onto suppliers who do not face fuel costs, and more importantly, onto customers. Given PJM’s market structure, it should be no surprise that (except for resources facilitated by RPS programs and other state policies) virtually all new construction financed on a merchant basis in the region has been gas-fired. Gas-fired resources have relatively low upfront capital costs, and have an advantage in capacity markets, where they can offer a lower price with the knowledge that they will be able to recover a large share of fixed costs with high certainty through their low-volatility spread between energy prices and fuel costs.

But the massive boom in gas-fired resources in the PJM region imposes a large fuel price risk on consumers, while simultaneously setting the power sector on course to create massive amounts of emissions, pollution, and other environmental impacts caused by the natural gas supply chain in a manner that is at odds with state climate and environmental goals. Many states justifiably are not pleased with this market outcome and are seeking to modify the generation mix through environmental policies and other state regulations. Yet the very best policy options to reduce the fuel-price risk that consumers face are precisely what...
PJM's proposals (and particularly the MOPR-Ex option) frustrate. State-facilitated long-term power purchase agreements between load serving entities and renewables resources with no fuel costs leave less energy that is vulnerable to the swings of PJM's high fuel-price risk energy market.

Long-term contracts also have the added advantage of making financing for capital-intensive assets cheaper, further reducing the costs and risks for customers. But MOPR-Ex would block capacity market access for resources supported by these contracts, and capacity repricing would adjust market prices upward in response to them.

Rather than modifying its market to be more at odds with state policies, PJM should instead consider how it can help states achieve the resource mixes that they desire at lower cost. Such a focus could yield policy prescriptions that benefit both customers and suppliers. For example, while states may want to encourage utilities to financially hedge against fuel risks using futures and swaps, that is currently challenging to accomplish given the illiquid market for long-term hedging products. PJM should consider ways to facilitate a more liquid market. PJM could also consider how to facilitate long-term power purchase agreements at lower cost, better incorporating such agreements into its market design or even providing a market platform by which such transactions may occur.

In summary, while state policies affecting PJM market prices is not a problem, there are things PJM can do to provide a market that better facilitates state policy choices. Focusing on those areas would increase market efficiency and benefit customers rather than saddling them with unnecessary costs.

PJM is wrong in suggesting that such state contracts "shift risk from private capital to customers." PJM filing at 46. Where states procure new renewable resources through a competitive process awarding long-term contracts, that lowers the overall cost while simultaneously reducing risk for both suppliers and customers by providing both with long-term price certainty.
II. Threshold legal and procedural flaws bar the Commission from approving any of the proposed PJM proposals

Multiple, central deficiencies in PJM's filing render it inconsistent with the requirements of the Federal Power Act, and the Commission should summarily reject it.

A. PJM filed a set of poorly developed proposals flouting the principle of stakeholder engagement

In this filing, PJM ignores the definitive preference of its stakeholders to maintain the status quo and avoid changes to the capacity market structure to account for the impacts of state policies. Despite that clear preference, ample evidence that PJM is oversupplied with capacity, and the fact that its capacity market is structured to provide more than adequate resource supply under the status quo model, PJM now asserts that "[d]oing nothing . . . is not an option." 191

Although PJM retains the ability to propose changes to its capacity market rules absent stakeholder endorsement, the Commission has previously recognized that "stakeholder consensus is an important factor to consider in reviewing the justness and reasonableness of a rate design." 192

Broad stakeholder support is particularly relevant on issues, like the one presented here, where the Commission must balance the conflicting interests of different constituencies. 193

A lack of broad stakeholder support for the two proposals offered here also means that critical elements of those proposals were not subjected to the kind of stakeholder scrutiny that a proposal with stakeholder buy-in would undergo. 191

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191 PJM filing at 17.
Just as "stakeholder support alone cannot ultimately prove that a rate design is just and reasonable," stakeholder disapproval of a pending proposal does not demonstrate that it is unjust and unreasonable. However, the lack of stakeholder support weighs against approval of either capacity repricing or MOPR-Ex because it demonstrates that neither proposal achieves an acceptable balance of the interests of states, generators, consumers, transmission owners, and other interests. In this case, as described below, the majority of the stakeholders are correctly skeptical of both proposals because neither is just and reasonable, and both would arbitrarily distort market prices and inflict serious harms upon consumers.

PJM's rejection of its stakeholders' preference for the status quo in these circumstances undermines the role the stakeholder process has long played in vetting potential changes to market rules. Engaging stakeholders in an exhaustive process, which provided PJM with every opportunity to convince those parties that inaction was "not an option," and then ignoring the outcome of that process undermines confidence in the process itself. Knowing there is a high likelihood that their preferences will be disregarded, stakeholders will logically dedicate fewer resources to these discussions, resulting in less-informed decisions. Even PJM has acknowledged that its stakeholder process has become less effective, announcing in a recent letter that another emerging issue provides an opportunity "for the stakeholder community to come together and demonstrate that the PJM stakeholder process can deliver thoughtful and timely consensus."
While issues of RTO governance are properly addressed in a stand-alone proceeding designed to explore those issues, the Commission should be mindful that approval of RTO proposals made without stakeholder endorsement could exacerbate the lack of trust in those processes that are so critical in ensuring that high-quality proposals are offered for the Commission's consideration.

B. PJM's filing is deficient under section 205 of the Federal Power Act

PJM attempts to evade the requirements of the section 205 of the FPA and NRG Power Marketing, LLC v. FERC, by filing an ambiguous and multi-faceted proposal with the Commission and inviting it to choose a path forward. This endeavor to disguise a section 206 proposal under section 205 cloth is as transparent as it is unavailing. While PJM claims that it is making its filing under section 205, this self-serving characterization is inaccurate. PJM's filing fails to meet the requirements of section 205 and should therefore be rejected outright, or at minimum be characterized as a filing under section 206 of the FPA (which would also compel rejection of the filing given PJM's failure to explain or even state that its current tariff is not just and reasonable).

Section 205 sets a lower bar for Commission approval than section 206, so along with that easier-to-meet standard come certain requirements and limitations on the Commission's...
Under section 205, "FERC must accept proposed rate changes . . . so long as the changes are just and reasonable.

In contrast, under section 206, FERC must find the current rate unjust and unreasonable and the proposed rate just and reasonable: "It is the Commission's job—not the petitioner's—to find a just and reasonable rate.

Section 205 restricts FERC to a "passive and reactive role" in reviewing the proposed rate, as opposed to its more active role under section 206.

Further, to be properly filed under section 205, a tariff revision must "plainly" state the change sought, be sufficiently definite to take effect by operation of law, and provide adequate notice to consumers.

Here, PJM has asked FERC to go far beyond a "passive and reactive role" and to choose among a variety of competing multi-faceted proposals, which it invites the Commission to combine or deconstruct and reassemble in a manner that raises countless possible outcomes.

PJM's vague proposal fails to provide customers with adequate notice, and could not possibly become effective without further guidance from the Commission. While PJM indicates that it would consent to various responses from the Commission, this attempt to circumvent section 205 does not cure its proposal's failure under that section.

Id. at 113 (emphasizing the function section 205 requirements serve to protect utility customers).

Id. at

Maryland Public Service Comm'n v. FERC, 632 F.3d 1283, 1285 n.1 (D.C. Cir. 2011).

NRG Power Marketing, LLC, 862 F.3d at 114 (quoting Advanced Energy Management Alliance v. FERC, 860 F.3d 656, 662 (D.C. Cir. 2017) (internal quotation mark omitted)).

See also City of Winnfield, La. v. FERC, 744 F.2d 871, 875-76 (D.C. Cir. 1984).

City of Winnfield, 744 F.2d at 876.


Id.

PJM filing at 5-7 (proposing further resolution of the proposals' details through additional process).
PJM's "jump ball" is more accurately described as "jump balls." "Jump ball" implies that there are two competing proposals. While even that would be problematic, PJM's proposal actually offers a multitude of options. Capacity repricing is one option, and under the broader heading of MOPR-Ex, PJM raises two more different alternatives. One has an exemption for renewable portfolio standards. The other does not.

Then, there are untold permutations among those three options on which utility customers have received no conceivable notice. PJM has invited the Commission to send the matter to a settlement judge for resolution if there is an undefined "subset of issues" that require acceptance "subject to suspension and further proceedings."

Indeed, a February 16, 2018 letter from Andrew L. Ott, the President and CEO of PJM, demonstrates PJM's desire to file an intentionally ambiguous proposal that places the Commission in its section 206 role of proactively designing the rate that will take effect rather than its "passive and reactive" section 205 stance. Mr. Ott stated that because the choice among policy options involves "a balancing of federal and state interests," the PJM Board "concluded that this question should fall to the Commission as the federal policymaker not to the PJM Board."

Mr. Ott's letter even contemplates continuing stakeholder engagement at the Commission after FERC makes a policy call through the use of "a time-bound settlement judge proceeding, with expectation that such a process will bring refinement, compromise and more..."
consensus support for what ultimately will be presented to the Commission later this year as a package of proposed rule changes.

210 In presenting this confusing mix of adjustable options and inviting the Commission to send the matter to a settlement judge to modify them in an unspecified manner, PJM's proposal fails to provide adequate notice to utility customers. It fails to "plainly" state the changes to be made to any rate, charge, or service, such that customers "do not have adequate notice of the proposed rate changes or an adequate opportunity to comment on the proposed changes." Section 205's requirement to "plainly" state the changes to be filed is legally crucial not only for its notice-serving function, but also because specificity is required to indicate what the proposed rate will be that takes effect in 60 days by operation of law should the Commission not act.

213 Here, there is no sufficiently plain or definite rate such that this could happen, because while PJM has expressed a preference for capacity repricing, it has also proposed other options that it asserts are just and reasonable. If FERC fails to act within 60 days, which capacity construct would take effect by operation of law? This ambiguity in and of itself betrays PJM's assertion that it is making a section 205 filing.

Nor does PJM's attempt to confer before-the-fact consent on FERC cure its violation of section 205's requirements. Just as PJM's after-the-fact consent to a non-minor modification by FERC of a proposed rate failed to provide adequate notice to consumers in NRG Power Marketing, LLC, so too does before-the-fact consent to FERC choosing among a multitude of non-minor and dramatically disparate options. Taken to its logical extreme, PJM could file a
The law, however, requires more than that. Under section 205, a utility cannot provide a blank check to FERC or even one that is partially filled in. If a utility wishes to do that, it must file a complaint under section 206, after which time "[i]t is the Commission's job—not the petitioner's—to find a just and reasonable rate." 

PJM's attempt to rely on past Commission orders in which a utility presented the Commission with two or three options under section 205 of the FPA or section 4 of the Natural Gas Act is unavailing. Each of the orders cited by PJM preceded NRG Power Marketing, LLC, when the law was less clear on the Commission's role in reviewing a proposed rate and whether the Commission could approve a rate subject to conditions that the utility could accept or reject. Moreover, in each of the orders cited by PJM, no party appears to have objected to the fact that options were presented to the Commission. Nor, apparently, was there an open-ended invitation to the Commission to submit the matter to a settlement judge for resolution of an undefined and potentially boundless "subset of issues" relating to the proposed rate. Finally, none of the orders choose or modify a market design on a matter that involves billions of dollars. Instead, the orders address far more limited resource-specific issues (such as cost recovery), not the structure of the market itself. Far from supporting PJM's request, a comparison of the orders and PJM's filing underscores the unprecedented nature of PJM's request under section 205.

Maryland Public Service Comm'n, 632 F.3d at 1285 n.1. 
PJM filing at 48-49. 

There is a subtle but pernicious aspect to PJM's filing a number of disparate proposals under section 205. By doing so, in effect, PJM has deployed a "divide and conquer" strategy in which stakeholders may opt for one design over others as the lesser evil among them. This may give the Commission the misleading impression that there is more support for a design than actually exists. If each proposal were considered separately – as happened in the PJM stakeholder process itself and as should properly
Because PJM's filing has failed to meet the requirements of section 205, it should be rejected.

Even if it is not rejected, it can only be properly considered under section 206. Under section 206, PJM's jump ball fails because PJM has not shown that its current rules are unjust and unreasonable. While PJM has asserted that there is a "gap" in its rules with respect to revenues earned pursuant to state policies, this assertion, without more, is insufficient to meet its burden under section 206 of the FPA. Nowhere in its 600-page filing has PJM alleged that its current capacity construct is unjust and unreasonable. It must therefore be rejected.

C. PJM fails to meet its threshold burden to offer a clear rationale for its proposals and substantial evidence to back that rationale.

Even if the Commission improperly proceeds to consider PJM's proposals under section 205 of the Federal Power Act, PJM has also failed to meet its burden under that standard. "Section 205 places the burden of proof on the public utility to show that its proposed tariff change is just and reasonable and not unduly discriminatory or preferential."

The Commission requires substantial evidence demonstrating that the statutory standard is met. PJM does not meet this threshold task. At the bare minimum, PJM must clearly articulate a rational theory by which its market design is just and reasonable and not unduly discriminatory or preferential. No such clear rationale is presented in PJM's filing. As best we can understand it, PJM's theory is that any of its proposals are just and reasonable because they address the price-suppressive effects from state actions that pose a concern to market outcomes. But it never happen under section 205 – there would be a clearer indication of the extent of the opposition.

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18 C.F.R. § 35.5 (requiring the Secretary of the Commission to reject deficient filings).

PJM filing at 18.


Id.
clearly explains what that category of state actions are, and why those actions pose a threat that is different in kind or scope from others that are not the target of the proposals. Even PJM admits that some price-suppressive effect is "workable.

So what are those lines, and are those distinctions backed by evidence? The answer to the first question is impossible to divine from PJM's filing, and the answer to the second is clearly no. PJM offers a range of different theories, none backed by any clear logic or evidence.

For example, PJM suggests that the harm to market outcomes comes from "programs which target large-scale, unit specific resources." Yet PJM never explains why these programs would be different in terms of their market effects from, for example, price supports that are provided to an entire category of resources at large magnitudes.

Nor does PJM articulate, even loosely, what its benchmark is for a "workable" level of impact on the market. Even if it had, PJM's proposals do not even target programs that focus on large-scale, unit-specific resources; both PJM's proposals largely capture many small-scale resources that are not recipients of "unit specific" support, while excluding others state actions that do target large-scale, unit-specific resources.

PJM's explanation is not internally consistent, much less backed by substantial evidence.

PJM filing at 15 (stating "that organized markets can and must continue to accept a tradeoff between perfect competition and interventions that affect price outcomes for the benefit of some at the expense of others").
PJM offers analysis that purports to show that the programs targeted would impact revenues for sellers of tens of thousands of megawatts of capacity in PJM.

We show below that this analysis is based on fundamentally flawed assumptions. Its conclusions are therefore unsound, and it cannot provide a reasoned basis for the proposal.

But even assuming the analysis is valid, the lessons it offers contradict PJM's own logic for focusing on some state programs and not others. All PJM's analyst claims to show is that when a certain large quantity of capacity with zero offers is added to the market and the auction is run again (without allowing the market to adjust), price goes down.

And it goes down more if there are more megawatts of zero offers. But if that effect is sufficient under PJM's theory to intervene, then the cumulative total capacity affected by government actions should matter as much or more than whether any one program is targeted to a specific unit or not—because all that matters is the total megawatts of capacity that is offering at zero. Following PJM's logic, there is no reason at all to ignore zero offers from one quarter of the capacity in the market (i.e., the traditionally regulated share of capacity) while focusing on zero offers from five percent of the capacity in the market (i.e., renewables). Yet that is exactly what PJM proposes to do.

The failure to offer up a rationale for its proposals is particularly glaring with respect to its targeting of demand response and price-responsive demand policies. Though they comprise nearly a third of the capacity that PJM expects to immediately target under its proposals, PJM never even describes what these programs are or why they should be targeted. The record is

PJM filing at 16 (discussing the Keech Affidavit conclusions).

See infra Argument section III.C.3.

PJM filing, Keech Affidavit at PP 6-8.

Id. at P 18.
barren of even a token explanation of PJM's belief that these programs pose meaningful concerns of price suppression.

D. PJM relies on the wrong legal standard and thereby fails to provide the record necessary to approve the proposals.

As a final threshold legal flaw, PJM cannot demonstrate its proposals are just and reasonable because PJM relies on a standard that lacks a basis in longstanding Commission precedent and that would leave consumers without statutory protection. By focusing on the wrong, investor-focused standard, PJM fails to address how its proposals will impact wholesale customers and thereby denies the Commission the record it requires to evaluate whether the approach is just and reasonable. PJM's reliance on a standard that is skewed toward generator interests obscures the fact that all of PJM's proposal are a bad deal for consumers, hiking prices for no value. Yet failing to provide the relevant information the Commission needs to assess the proposal alone is sufficient grounds to reject the filing.

Similarly, PJM fails to include any discussion at all of the relation between its proposal and energy storage policies. This contributes to the proposal's failure to meet section 205's requirements, as discussed in Argument section II.B, and to the extent PJM's proposal does affect energy storage policies, it constitutes a failure to provide substantial evidence.

Maryland People's Counsel v. FERC, 761 F.2d 780, 786 (D.C. Cir. 1985) (remanding for failure to consider "highly relevant factors" related to an order's impacts on consumers).

PJM filing at 1-2 (citing ISO New England, Inc., 162 FERC ¶ 61,205 at P 21 (Mar. 9, 2018) ("CASPR Order")).

PJM filing at 16, 45.

PJM points to the Commission's recent novel articulation of the "first principles" of the capacity markets in its recent order approving ISO New England's new capacity market construct.

It argues that the RPM cannot continue to advance these so-called "first principles" in the face of state policy actions.

PJM makes achievement of these new principles a core benchmark for approval of its proposals, structuring its argument and evidence against that...
Fatally, however, much like the Commission's reliance on these principles in the CASPR Order, PJM boils these principles down to a test of investor expectations. For example, PJM points to the market's ability to enable private equity investment as a key marker that market rules are just and reasonable. Indeed, "investor confidence" sufficient to ensure resource adequacy at just and reasonable rates is the "ultimate goal." As such, while PJM acknowledges that consumer interests are one parameter to consider in evaluating a capacity market design, PJM frames those interests very narrowly and in terms of whether the market is stimulating enough of a certain kind of investment.

The slim explanation PJM offers the Commission on the impacts of its proposals to customer interests is the unsubstantiated claim that subsidies insulate suppliers from financial risk at the expense of customers. The claim is factually incorrect with respect to the state renewable portfolio standards and demand response programs PJM targets, and also demonstrates the inadequacy of PJM's framing of consumer interests. PJM is silent on how wholesale customers are directly affected by the two proposals. Instead, PJM's articulation of the benefits to consumers is nothing more than that the PJM proposals will insulate certain investor expectations from being thwarted by the regulatory risks of some public policies.

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236 See, e.g., id. at 18 (framing discussion of its proposals in terms of threat to capacity market principles).
237 Id. at 12 ("This is precisely the kind of investment and private capital risk-taking that just and reasonable wholesale market rules should enable.").
238 Id. at 12, 21.
239 Id. at 32 n.86, 46.
240 Id. at 11, 46.
241 Id. at 46.
242 See infra Argument section III.C.3.d. Energy storage policies, not clearly targeted by PJM but potentially swept within the ambit of its proposals, may also be structured competitively.
formulation, it is enough for the Commission to know that the market will give investors the confidence they need to profit through the merchant generation business, because thriving merchant generation means "[r]isks that were traditionally borne by customers have been shifted to investors."

In other words, because the shift from traditionally regulated, vertically integrated utilities to competitive markets has indeed brought wholesale customers benefits, PJM's standard dictates that it is enough to incant that 'more competition is better' to address the consumers impacts of a proposal.

PJM is wrong that investor confidence can serve as a proxy for consumer interests in FERC's determination of whether a rate is just and reasonable. The Commission cannot so neglect its "primary aim" to protect consumers "from excessive rates and charges."

Such "protection of the public interest" must be clearly "distinguished from the private interests of the utilities."

Evidence of a voracious appetite to invest in the market is not an adequate safeguard of consumer interests—one need only consider the latest Wall Street financial meltdown to

Indeed, as discussed infra Argument section III.B.2.d, PJM focuses on a particular class of investor.

PJM filing at 12.

Fed. Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348, 355 (1956) ("That the purpose of the power given the Commission by [section] 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities, is evidenced by the recital in [section] 201 of the Act that the scheme of regulation imposed 'is necessary for the public interest.'"); Pennsylvania Water & Power Co. v. Fed. Power Comm'n, 343 U.S. 414, 418 (1952) ("A major purpose of the whole Act is to protect power consumers against excessive prices."); Xcel Energy Servs. Inc. v. FERC, 815 F.3d 947, 952 (D.C. Cir. 2016) ("It is long-established that 'the primary aim [of the FPA] is the protection of consumers from excessive rates.'") (quoting Mun. Light Bds. of Reading & Wakefield v. Fed. Power Comm'n, 450 F.2d 1341, 1348 (D.C. Cir.1971)); Jersey Cent. Power & Light Co. v. FERC, 810 F.2d 1168, 1177 (D.C. Cir. 1987) ("[F]rom the earliest cases, the end of public utility regulation has been recognized to be protection of consumers from exorbitant rates.") (quoting Washington Gas Light Co. v. Baker, 188 F.2d 11, 15 (D.C. Cir. 1950)).

recognize this truth—and the Commission has never held as such. Nor can examining a single factor, whether investment in merchant generation will thrive under a capacity construct, sufficiently account for the consumer impacts of a proposed market construct. The Commission's long-standing interpretation of the FPA entails consideration of the inherent trade-offs across consumer and supply interests in determining whether a rate is just and reasonable, and does not permit such shortcuts.

In fact, each of PJM's proposals presents a classic case where confidence for investors in supply resources will not translate into customer benefits. As explained in Argument section III.C.1, capacity repricing increases supplier profits while structuring competition in a manner that does not benefit customers, while MOPR-Ex benefits suppliers by channeling customer dollars toward unnecessary redundant capacity. In simply assuming that what is good for suppliers is good for customers, PJM has failed to put forward the record necessary to conduct its vital task of balancing consumer and supplier interests.

Of course, whether prices provide adequate signals to invest in new capacity when such capacity is needed is an important factor in the Commission's balancing test. It has never, however, been an exclusive factor that overrides the need to consider other factors and their impacts on consumer and supply interests.


Promoting Transmission Investment through Pricing Reform, 116 FERC ¶ 61,057 at P 21 (July 20, 2006), reh'g granted in part by 117 FERC ¶ 61,345 (Dec. 22, 2006), decision clarified on denial of reh'g by 119 FERC ¶ 61,062 (Apr. 19, 2007) ("The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests. It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our polices must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives."); New York Indep. Sys. Operator, Inc., 122 FERC ¶ 61,064 at P 54 (Jan. 29, 2008), order on reh'g, 125 FERC ¶ 61,299 (Dec. 18, 2008) (rejecting use of updated demand curve factors that "do not recognize the need to balance the impact on consumers with the need to provide correct price signals for new generation entry").
III. PJM's proposals both fail to meet the standard for the Commission to approve the filing under section 205 of the Federal Power Act

A. Even under PJM's own flawed standard, PJM's proposals fail on each count. Even assuming that PJM's flawed investor-focused standard adequately protected customers, PJM's proposals do not perform well against the CASPR Order's capacity market principles. As discussed at length over the next sections, there is insufficient basis to conclude that either repricing or MOPR-Ex will in fact facilitate robust competition; provide the right price signals; result in selection of least-cost set of resources; ensure price transparency; shift risk from customers; or mitigate market power. PJM's proposals add unnecessary complexity to the capacity market construct, adding in a layer of unworkable administrative judgment about "what is a subsidy" that will cloud market certainty, lead to arbitrariness in price signals, and obscure price mechanics. The arbitrariness of determining which regulatory risks incumbent investors must be protected from, and which ignored, does nothing to shift risk away from consumers or enhance competition in the markets. Rather, it is simply another form of shifting who the winners and losers are, but based on PJM's line-drawing. Absent any principled economic rationale underpinning either market construct, PJM's proposals work to the benefit of certain competitors instead of competition.

B. At its core, PJM's proposals are based on arbitrary line-drawing, which results in undue discrimination against certain buyers and sellers. The core to each of PJM's proposals is the definition of an "actionable subsidy," which is the basis for application of both capacity repricing and MOPR-Ex. PJM claims that it targets...
state policies based on their "market impact." This is false. PJM incorporates no criteria to link the targeting of state policies to any actual effect on the market. PJM instead uses a proxy, revenue-based measure for market impact that even it admits will affect capacity offers that have no market effect. At the same time that it claims to be focused on policies that pose "legitimate price suppression concerns," PJM ignores or exempts other state policies that cumulatively provide billions of dollars in incentives for resources that participate in the RPM. The defining feature of PJM's proposals—drawing a line to define a "subsidy" that supposedly threatens the capacity market—is so arbitrary and riddled with inconsistencies as to be meaningless. The arbitrary nature of PJM's proposal results in direct harm to wholesale customers and, under MOPR-Ex, capacity sellers. PJM's Repricing Proposal arbitrarily subjects some customers, those located within Load Deliverability areas ("LDAs" or "capacity zones") where resources are deemed to be subject to "actionable subsidies," to higher prices even though these customers are no different than customers located outside of that LDA. In each case, resources located within the customer's service area are benefiting from state policies and pose the same hypothetical threat to capacity market prices. Yet under PJM's proposal, customers in one area face significantly higher wholesale capacity prices than the other set of customers. Similarly, MOPR-Ex arbitrarily forces some customers to pay for unneeded capacity (ostensibly, to mitigate the price-suppressive effects of a targeted policy) while others, who are equally affected by a state policy that has the same theoretical market effect but is not deemed "actionable," are not. PJM's proposal is a textbook case of undue discrimination against certain consumers.
imposing excessive, discriminatory costs that will easily range in the billions of dollars per year.

While PJM makes ensuring investor confidence the key touchstone of its proposals, its arbitrary definition of a subsidy results in uneven treatment among investors. Under MOPR-Ex, market participants who have based their investments on the expectation of the regular application of certain state laws (such as the longstanding RPS programs) lose out; while at the same time other investors who have relied on state policies that are not deemed actionable but have the same potential market effects (Kentucky coal incentives or Pennsylvania development zones) do not. To the extent investor expectations are a rightful subject of the Commission's just and reasonable standard at all, PJM's proposal results in exactly the unduly discriminatory application of the standard that is prohibited under the Federal Power Act.

1. PJM's definition of "actionable subsidy" is arbitrary

While historic versions of the MOPR were in fact triggered by projected impacts on the clearing price, PJM elected not to base its definition of an "actionable subsidy" on the market effects of a state policy. Instead, PJM's definition of an "actionable subsidy" under both proposals deems any form of support to a resource that exceeds one percent of its projected...
PJM argues that this definition reflects that "not every subsidy impacts the seller's offer to a degree that materially affects its offer price," suggesting that the one percent revenue trigger is a threshold for revenue that will impact a market participant's offer behavior.

PJM also claims that this threshold is meant to target subsidies that affect market clearing prices, stating that its definition "ensure[s] that only those generation resources that receive a subsidy that warrant action based on design or market impact" qualify.

But PJM offers no evidence or reasoning on either point. It is not at all clear, for example, that support that is a little less than one percent of the revenue of each resource would not affect offer behavior, but support that is a little more than one percent of revenue will. Or, accordingly, that the former (just under one percent) will not affect market outcomes, but the latter (just over one percent) will. This is particularly true if one imagines that the first program benefits tens of thousands of megawatts at a cumulative value of billions of dollars, but the second affects only a few thousand megawatts and at a much lower total dollar value.

A subsidy of just under one percent of a 1000 MW resource's offer price, for instance, is nearly 50 times greater in magnitude than a subsidy of just over one percent a 20 MW resource. If either resource would have cleared in the capacity market with the subsidy but fails to clear without, the smaller subsidy on the larger resource would far outweigh the smaller one in terms of market impact. PJM's decision to focus on relative value of support to the resource (rather than definition of an Actionable Subsidy) "generally mirrors that PJM is proposing under Capacity Repricing." PJM filing at 100.

PJM filing at 74 (citing proposed PJM Tariff, Attachment DD § 5.14(j)(2)(d) (Option A)). PJM incorporates two other size thresholds into its Repricing Proposal. Five thousand MWs of actionable subsidy must enter the entire PJM market, or greater than or equal to 3.5% of a given LDA reliability requirement, before Repricing is triggered. PJM describes this as a "transition mechanism" to provide the market time to adjust to new rules.

Id. at 92.
80

than to the market) systematically favors larger resources, who are able to receive subsidies far larger in magnitude than those received by smaller resources without being mitigated.

PJM's own testimony contradicts the notion that the size of a subsidy is determinative of whether an offer from a resource materially affects the market. As Mr. Giacomoni, PJM's declarant, describes, "the size of the subsidy does not, by itself dictate whether a resource would be economic in PJM's market . . . .[d]epending on the resource's costs, and the revenue the resource receives in the PJM energy and ancillary service markets, the subsidy payments could effectively be surplus."

In other words, PJM's revenue threshold will capture and reprice resources that are economic and whose offers, even by PJM's judgment, are therefore not price-suppressive.

Moreover, as scholars from the Institute for Policy Integrity make clear, simply affecting an offer does not necessarily equate to an effect on clearing prices:

Any decrease in the bid of an infra-marginal unit that would have cleared the auction anyway, all else equal, would not affect the market clearing price. Thus, externality payments can affect the auction price only in limited situations: (1) when they induce entry (or prevent exit), increasing available supply of capacity, and hence lowering the market clearing price; or (2) when they directly lower the marginal bid, and hence the market clearing price.

Thus, the proposals do not actually target "market impacts" or "price-suppression" as PJM claims, though PJM stakes the reasonableness of its policies on the ability to evade those effects.

2. PJM carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations

PJM contends that its definition of an "actionable subsidy" is calibrated to target policies with price-suppressive effect. Yet it adopts a grab bag of justifications in determining which

259 PJM filing, Giacomoni Affidavit at P 36.
260 IPI report at 15.
types of resources to exempt from that definition. While PJM claims that it aims to exclude "the types of resources that are not likely to raise price suppression concerns," even a superficial consideration of the exemptions show that not to be the case.

PJM proposes to allow self-supply to participate unmitigated into the capacity market, without the previously applicable net short and net long thresholds, because "new entry offers from this class of sellers is only a very small slice of RPM offers."

PJM also claims that vertically-integrated utilities are unlikely to rely on price suppression as a strategy to benefit the non-self-supply portion of their portfolio (i.e., that these entities lack incentive to exercise market buyer power).

PJM offers no explanation for its "general industrial development" exception, other than that it had previously been a part of the MOPR.

Each of these reasons would provide equal basis to exempt resources supported by an RPS program. Solar resources, for example, comprise a smaller share of capacity clearing in recent BRAs than capacity relying on the self-supply exemption.

Renewable resources have long been recognized to be "a poor choice if a developer's primary
And renewable's exemption from the MOPR was approved by the Commission well before these other exemptions. PJM's rationale for exempting some categories of resources and not others is manifestly arbitrary. And closer examination only reveals more problematic inconsistencies between PJM's stated goals of the proposals and the scope of the policies it targets.

Clean Energy Advocates demonstrate in this section that PJM ignores policies that meet its own definition of a subsidy likely to have a material impact on the market. We do so, not so as to eliminate the exemptions PJM has set forth, but rather to point out the deep and incurable flaws in PJM's approach and the inherent unworkability of mitigation rules that aim to eliminate the effects of "material" government preference from the markets. Moreover, as explained later in the section, PJM's arbitrary line-drawing would have serious impact, imposing undue discriminatory harms to some customers and suppliers.

a. PJM arbitrarily exempts self-supply

In its filing, PJM describes the self-supply exemption as applying to resources "owned or controlled by entities with long-standing business models for capacity procurement, which do not raise concerns of possible price suppressive intent (e.g., certain vertically integrated, cooperative, and municipal utilities.)."

268 In its Resource Investment Whitepaper cited for other purposes in its filing, PJM called out the excesses of these same long-standing business models. "Regulated models," explains PJM, "do show a tendency . . . to embark occasionally on very expensive experiments, and evidence also suggests regulators are paying investors in rate-based..."
These tendencies sound strikingly like the “out-of-market support” that “forestall[s] retirement and defeat[s] the design objective of PJM’s market, at the expense of their competitors and wholesale consumers” that is precisely PJM’s purported target.

In direct contradiction to its claim here that the owners of such resources have little incentive to pursue market behavior that results in price suppression, PJM states:

“...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.”

In light of PJM’s strong assertion in this proceeding that “regardless of the state’s specific policy motivation, retaining or compelling the entry of resources that the market does not regard as economic, suppresses prices for resources the market does regard as economic,” PJM’s defense of the self-supply exemption is baffling. PJM describes regulated utilities as making precisely the kinds of uneconomic decisions to retain or retire resources that it believes distort market prices.

Nor is PJM’s characterization of the self-supply exemption as one that has long been in place – suggesting long-standing Commission endorsement of PJM’s (current) position – wholly accurate. The Commission rejected a self-supply exemption on numerous occasions through the...
history of its MOPR Orders, before accepting a narrow self-supply exemption premised on the very safeguards PJM proposes to eliminate.

As the Commission explained in approving the exemption, "we agree that with properly-calibrated thresholds measuring an entity's net-short and net-long positions, PJM's self-supply exemption will operate to identify those self-supply entities lacking the incentive to exercise buyer-side market power."

To ensure those thresholds remained "properly-calibrated," the Commission ordered PJM to submit tariff language "memorializing its obligation to review and, if necessary, revise these thresholds on a periodic basis."

In fact, PJM itself advocated against the self-supply exemption in prior proceedings pointing to essentially the same arguments it raises in this proceeding.

Finally, to the extent that PJM believes urgent action is needed because owners of legacy assets seek out-of-market support to forestall those units' retirement,

there is no basis to believe that assets that could benefit from the self-supply exemption are immune. FirstEnergy successfully pursued exactly this strategy with the transfer of the 1,984 MW coal-fired Harrison
Power Station, previously a merchant generator, from a FirstEnergy subsidiary to another West Virginia-regulated subsidiary. Analysts estimate the transfer of the plant to rate-payers shielded FirstEnergy from $160 million in losses over a three-year period. As demonstrated by the proposed retirement of a similarly-situated plant, Pleasants Power Station, when it was denied the terms of a similar transfer, the transfer likely forestalled Harrison’s retirement.

b. PJM arbitrarily exempts general economic development and local siting incentives

PJM proposes to exempt incentives (1) that utilize criteria designed to incent or promote general industrial development in an area and (2) from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality from its definition of actionable subsidies. PJM offers no explanation at all for its proposed exemption of general economic development and local siting incentives from both of its proposals. There is no basis to conclude that such programs do not provide large scale support that is narrowly targeted to specific energy assets, simply because they support development within a particular area or siting within a particular locality.

Indeed, as Koplow describes, “these large subsidies to individual facilities would affect power market structure no differently than an energy-related grant of similar size or a targeted...
Koplow's research provides only a sample of the kinds of programs likely to fall within this exemption, yet even that time-constrained review reveals numerous targeted subsidies to energy-related activities that exceed $20 million.

Some economic development programs work to the direct benefit of single resources, as is the case for the Pennsylvania Keystone Opportunity Zone and the Panda Power Hummel Power Station. The approximately 1,100 MW gas plant received state and local tax abatement to support its development, after receiving local official's approval under the development program.

Moreover, the very large billion-dollar economic development projects that directly support up- or down-stream energy sector activities can often hide cross-subsidization that benefits generation located nearby.

From more than a billion dollars in subsidies to local plants to support in-state demand for coal (and hence, cheaper coal generation) in Kentucky, to more than a billion and a half dollars in subsidy for natural gas development infrastructure in the Marcellus Shale in Pennsylvania (with corresponding benefits to cheap gas for regional gas generators) and a massive proposed natural gas hub laden with multi-billion dollars in foreign national and U.S. federal subsidy in the works for West Virginia, it is hard to pretend that ignoring these economic development programs ensures a...
level playing field for all resources – including fuel-free resources like renewables -- in the competitive markets. Nor can one discount the direct link between these kind of economic development incentives and the decisions of market participants to enter or exit the market. First, states are explicitly aiming to change market participant's behavior through these programs. For example, in 2015 West Virginia commissioned a 55-page study to identify tax incentives that would "ultimately boost coal production in West Virginia by incentivizing the state's utilities and manufacturers to use West Virginia coal."

289 There can be little doubt other states are taking similarly explicit steps to protect their preferred resources. Second, research finds a strong correlation between plant closures and the availability of these benefits intended to promote local economic development. For example, a generator that is in a state with an in-state coal mine (which are also the states that support coal as a local economic development benefit) is seven percent less likely to have closed by 2014 than a coal power plant without such in-state fuel inputs.

290 In concluding that state RPS programs must be subject to mitigation in order to protect the competitive markets, PJM reasoned that the programs "are expressly designed to promote the development or retention of specific types of resources" and the "available evidence indicates..."
that they do indeed contribute to that objective."

Under a consistent approach, PJM could not categorically exempt economic development and local siting programs, which share both of those same features.

c. PJM arbitrarily ignores "material" support to conventional generators

Finally, PJM appears to categorically ignore some types of government support that meet its own definition of "material" support. As noted above, PJM has concluded that the only existing resources that would be deemed "actionable" under its proposed tariff changes are 1,400 MWs of nuclear generation, 698 MWs of RPS program resources, and 981 MWs of price responsive demand and demand response resources (as of the time of filing).

Although the definition of an "actionable subsidy" would apply by its terms to upstream incentives that, for example, reduce the cost of fuel used by a capacity resource, it seems that PJM has discounted these programs. The omission of these other forms of incentives from PJM's consideration largely benefits conventional fossil fuel generators.

As subsidy expert Doug Koplow explains in his attached report, PJM focuses almost exclusively on purchase mandates. "But many subsidies that affect energy production prices do not fall into this category; rather, the most important subsidy mechanisms can vary widely by energy type."

"Policies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions."
Further, there is "some predictability" to the effect of focusing on just some types of government incentives:

[C]apital-intensive generation will be more affected by build times, financing conditions, and changes in demand during the build period. Electricity reliant on high volume flows of input fuels are affected by subsidies to key transport links, favorable policies for pipeline building, and subsidies to extraction. Accordingly, PJM's focus on one category of subsidies will have the effect of discriminating based on technology type.

Despite the limited time afforded by the comment period, Koplow identified billions of dollars in state support to conventional generators that would appear to have the same effects on behavior offer and, per PJM's theory, market outcomes as those targeted by PJM. For example, a $1.1 billion package of support to five coal-to-liquids plants in Kentucky would keep prices for coal artificially low for coal-generators in the region (including the many in-state coal resources), while a $500 million dollar tax incentive for sales and use of coal further lowers the fuel costs to generators in that state. Coal generators relying on Kentucky coal reap additional benefits from Kentucky's lax bonding and reclamation laws for coal mines, which artificially reduce operating costs for the affected mines. The dollar value of these unfunded clean-up and reclamation costs, which would otherwise fall upon coal mine operators and the cost of coal, reaches close to half a billion dollars in Kentucky. Moreover, unlike solar and wind which...
contribute less than one percent of installed capacity in PJM's capacity market, coal generation remains more than a third of installed capacity. Thus, even if only a small percentage of the affected generators changed their retirement decisions or adjusted their offers as a result of the Kentucky coal policies, the potential for market impact appears much larger than that of the RPS policies PJM instead targets.

To provide a test case to determine whether PJM might be excluding these policies because they do not provide "material" support, Koplow estimated the value of the benefits of one of the policies PJM ignores to resources participating in the PJM capacity market.

Pennsylvania has a special sales tax exemption for coal that results in revenue losses of about $125 million per year, and about $1.5 billion over the 2007-2018 period.

After breaking out the value of the subsidy that falls to coal exiting the state, or for uses other than electricity-production, Koplow compared this conservative value of the program to coal resources to the average revenue of a coal plant selling energy at the Western hub.

By PJM's own standards, the Pennsylvania tax incentive surpasses the one percent of revenue threshold of a "material" subsidy. Moreover, with more than 10,000 MWs of coal generation impacted by the Pennsylvania policy, this single program alone would trigger PJM repricing across the whole capacity market. Yet PJM appears to ignore its own standard in concluding that its proposal would not apply to any coal generation.

Id. at 25-27. Koplow concludes that this test case is "likely part of a fairly big group of material subsidies" outside the category that PJM focuses on.
The result of PJM's arbitrary line-drawing is discriminatory impacts against buyers and sellers. PJM's wholly arbitrary targeting of some state policies but not others with the same potential market effects, has severe and harmful consequences for both market participants and wholesale customers. The discrimination, because it is not based on any meaningful economic rationale or other reasonable distinction, is by definition "undue." The Commission must reject PJM's proposals to safeguard consumers from arbitrary and unduly discriminatory rates, and, with respect to MOPR-Ex, protect suppliers from partial and unduly discriminatory access to the market.

The Federal Power Act "fairly bristles with concern for undue discrimination." Section 205 (b) of the Act is unequivocal:

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No public utility shall . . . (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

In filing a revision to its tariff, PJM "bears the ultimate burden of demonstrating that the rate is not unduly discriminatory."

To start, it is clear that PJM's proposals would result in differential treatment for customers. Under the capacity repricing proposal, some resources will be designated as "actionable subsidies" which will then (after the 5000 MW or 3.5 percent LDA thresholds are passed) trigger repricing in a second run of the capacity market auction. Targeted resources will have their offers repriced to higher levels, and may be replaced by a higher offer (relative to its initial offer) in the supply stack. It is a design feature of repricing that the second run of the


308 16 U.S.C. § 824d.

309 Transmission Agency of N. California v. FERC, 628 F.3d 538, 549 (D.C. Cir. 2010).
92

As such, customers located within those LDAs will predictably face higher wholesale capacity prices than customers located in LDAs where no resources are deemed actionable.

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By PJM's own estimation, the price effects of repricing will be large: as much as ten percent higher clearing prices in constrained-LDAs, and an estimated two percent higher on average.

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As discussed at length in the next section, economist James Wilson concludes the price could be significantly higher, reaching into the billions of dollars.

The increase in costs for customers are likely even larger under MOPR-Ex. Instead of being subject to repricing, resources with actionable subsidies are quite likely to be excluded from the capacity market entirely. This leaves customers paying both the retail-side costs of the state program, but also with the cost of procuring replacement capacity from the market that is not really needed. Like the capacity repricing proposal, under MOPR-Ex customers located in jurisdictions with polices that are deemed "actionable" will face substantially higher capacity market prices than customers in jurisdictions where policies are not.

Under MOPR-Ex, because the targeted resources are most likely excluded from the market, supply interests are also discriminatorily impacted. The targeted resources lose a significant revenue source that non-targeted resources do not. PJM makes much about how the high rates of new gas build reflect a "market expectation" that new entry can displace incumbent resources.

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Yet investment strategies are as diverse as the variety of investors in the market, and PJM ignores that many investors (not just renewable developers) could reasonably expect to...
rely on duly adopted and longstanding state laws and policies affecting the market. Where a class of investors relies on a policy that is deemed "actionable," their expectations are thwarted. But other types of investors that rely on state policies that are not deemed actionable do not face these same impacts.

Discriminatory treatment, of course, is only prohibited if it is "undue." Here, PJM's proffered basis for the differential treatment of some resources—and accordingly, for the differential prices that affect consumers—is that certain "types of resources that are not likely to raise price suppression concerns." But as described at length above, PJM is without factual support for this claim, and substantial record evidence demonstrates it is false. Indeed, even under PJM's own (flawed) test of materiality, PJM is excluding resources that receive large enough incentives to be considered "likely to raise price suppression concerns." To take even one example, the more than 50 million dollars in external support provided to the Harrison Power station in one year easily exceeds the one percent of expected market revenue threshold to be "actionable." Moreover, again tracking PJM's own logic, the extra-market support to the Harrison Power station raises precisely the same set of concerns as a ZEC by preventing the retirement of an aging, less efficient incumbent resource. Customers in Illinois will face dramatic increases in wholesale capacity market prices under either the capacity repricing or MOPR-Ex proposals, while customers in West Virginia will not. But by the logic of PJM's own criteria, there is no meaningful difference between the customers in Illinois and in West Virginia—both are served by resources that receive "material subsidies" that pose a price suppressive threat to the market. This is undue discrimination, pure and simple.

\[314\] Id. at 73.
By the same token, there is no basis for the owner of the Harrison Plant to benefit from "subsidized" access to the capacity market, while the owner of the Quad Cities nuclear plant does not under MOPR-Ex.

The Commission previously declared that "we are not persuaded that determining what constitutes a 'subsidy' or a 'discriminatory payment,' . . . will be a less subjective and more precise means of preventing uneconomic entry."

315 PJM's deeply flawed and highly inconsistent attempt to do exactly that proves the point. Because PJM's arbitrary proposals unduly discriminate against both consumers and supply, the Commission must reject the tariff filing.

C. Both capacity repricing and MOPR-Ex are unjust and unreasonable because they require customers to pay more for capacity than necessary to ensure resource adequacy.

Each of PJM's capacity proposals is unjust and unreasonable because each distorts capacity prices in a manner that harms customers. Capacity repricing forces customers to pay more for the same level of resource adequacy. It sets prices, year after year, to what they would have been if state policies did not exist. This transfers wealth from customers to suppliers that clear in the market, but will not in fact induce any greater competition or increase resource adequacy.

316 MOPR-Ex, by contrast, forces customers to buy far more capacity than necessary. It does so by effectively blocking capacity market access for state-sponsored resources and forcing customers to procure redundant capacity from other sources.

Both proposals suffer from the same fundamental flaw: they treat revenue from state policies as different from any other revenue or cost affecting a resource's bottom line. It is not. Revenue earned pursuant to state policies does not "artificially suppress" PJM capacity market prices, and should not be separately adjusted for by PJM. In fact, the bulk of so-called "state..."
subsidies” targeted by PJM are “[e]xternality payments” that account for “the external costs that electricity generation imposes on society” that are not priced into PJM’s markets.

Because such costs “should be taken into account when deciding whether or how much a resource should be used,” they make PJM’s markets more efficient, not less.

1. Capacity repricing inflates capacity rates without benefitting customers. Under capacity repricing, PJM would procure the correct amount of capacity for the region’s customers, but at inflated prices. Capacity repricing would administer PJM capacity auctions in two stages. The first stage of the auction would determine which resources clear. PJM would arrive at the correct amount of supply in this stage by applying status quo rules wherein a resource earning revenue from sales of products such as renewable energy certificates created pursuant to state law could reflect those revenues in its offer price.

However, PJM would then proceed to overcharge customers by inflating prices through a second stage auction used to set the price paid to resources that cleared in the auction’s first stage. In the second stage of the auction, which would apply once the quantity of capacity receiving state-based revenue passed a specified threshold, PJM would modify the offers from any resource receiving a so-called “actionable subsidy” to an administratively determined “Actionable Subsidy Reference Price” that would exclude revenue earned under the applicable state policy.

As shown by PJM, this offer adjustment would allow units not receiving a...
This process, by design, would set prices higher than the amount necessary to induce the entry and retention of resources that cleared in the auction's first stage. That is not permissible under the Federal Power Act. A capacity market's purpose is "to attract and retain sufficient capacity to meet [a region's] reliability targets on average over time, at least cost to customers." Capacity pricing would incent essentially the same mix of resources as operation of PJM's status quo market rules, but at higher cost.

While PJM vaguely characterizes its capacity repricing proposal as providing for greater "investor confidence," it fails to specifically explain how this proposal would alter the pool of resources.

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**Figure 6: PJM Filing, Capacity Repricing Illustration**

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<table>
<thead>
<tr>
<th>Subsidized Units</th>
<th>Unsubsidized Units</th>
<th>Marginal Unit, but does not receive commitment</th>
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**Second Stage of Base Residual Auction, Capacity Price Determined**

- Restated Capacity Price = $40
- Cleared Capacity 1,000 MW
- Subsidized offers replaced with Actionable Subsidy Reference Price.
supply offers in any way that would meaningfully benefit customers or provide them with any greater resource adequacy. Closer examination of the proposal reveals that it would not.

Capacity repricing provides higher compensation to the exact set of resources that would clear in PJM's market with or without any market adjustments (i.e. the resources that would enter or remain in PJM's capacity market without the operation of the new second stage of the auction). Meanwhile, higher prices provided by the capacity auction's second stage would fail to induce any market entry or retention that would not otherwise occur because resources whose offers fall between the first and second stage clearing prices would still fail to clear. Because a resource earns no revenue when it does not clear, potential capacity market suppliers would continue to make market entry or exit decisions based on the auction's first stage clearing price, not the auction's second stage. Thus, while resource owners could have confidence that prices paid to clearing resources would be higher, that inflated clearing price would not meaningfully alter any resource's offer decisions, or change the choices of investors whether or not to attempt resource construction (except for inducing some inefficient bidding behavior, as described below). Under capacity repricing, resources would face virtually the same level of regulatory uncertainty they faced under the status quo operation of PJM's markets, because the auction round primarily influencing their entry and exit decisions—the first stage—would remain unchanged. Because it provides customers with higher costs and no benefits, capacity repricing is not just and reasonable.

Beyond this fundamental problem, capacity repricing is also unjust and unreasonable because it is structured in a manner that will skew market bidding incentives in a manner that would further harm customers. As economist James Wilson explains, a “bedrock principle” of

See infra section III.C.3.b.
capacity market design is that where a capacity market uses a sloping demand curve, the cleared quantity and price must fall on that curve. Capacity repricing violates that principle. As a consequence, market actors will not be adequately incented to compete to reduce market prices.

Under status quo market rules, resource developers who believe they can beat what would otherwise have been the market clearing price for capacity are incented to enter or remain in the market. As suppliers making lower offers enter or stay in the market, that pushes prices downward. But under capacity repricing, this fundamental feature of market operations no longer applies.

A resource developer that believes it can beat the price arrived at in the second stage of the auction will not enter the market unless it also believes it can beat the price in the auction's first stage. Accordingly, in capacity repricing, there is no natural operation of market forces that will provide for the development or retention of resources that narrow the margin between the first stage and second stage prices. This means that prices will not only be inflated, but also that they are likely to stay very inflated, year after year. Nothing puts competitive pressure on the second stage auction price to keep it low.

In fact, market actors are incented to do the opposite. By divorcing clearing market clearing prices from the process by which capacity obligations are determined, capacity repricing will incent many resources to provide offers that are not reflective of their true costs and revenues. As Wilson explains, it will create an incentive for higher cost resources whose offers are unlikely to clear in stage 1 to submit above-market offers where the owners of those

See Wilson Affidavit at P 50.

As James Wilson argues, “[f]unctioning markets and workable market and auction designs share the characteristic that a seller’s offer price will determine whether the seller will make a sale, and also the minimum price the seller might receive.” Wilson Affidavit at P 2.
A resource faces the incentive to do this because by submitting the higher offer, the resource has nothing to lose but may push stage 2 prices upward, benefitting the owner's other units.

This problem has been called an incentive to "clear out the top."

At the same time, resources that anticipate that their offer prices may fall above the stage 1 clearing price, but not so high as to risk being above the stage 2 clearing price, will be incented to "race to the bottom," submitting below-cost bids so as to secure capacity commitments while being paid at the higher stage 2 auction price.

Such a resource would be incented to bid below cost because so long as the stage 2 price exceeded its competitive offer, that resource would make money by securing a capacity commitment in stage 1. But while the resource owner would be rewarded for this behavior through such market manipulation, competition as a whole would suffer. Resource developers might be dissuaded from entering the market due to the risk that their offer might not be selected as a result of such manipulation even when their resource's costs and revenues would have otherwise dictated market success.

These concerns were raised by stakeholders in the CCPPSTF process, but PJM dismisses them summarily as "speculative."

Yet as Wilson explains, it is highly foreseeable that these skewed incentives would in fact translate into skewed bids.
large price gap between stage 1 and stage 2 of the auction, market participants would have a fair sense whether they should attempt to "race to the bottom" or "clear out the top." Reasonable assumptions about the amount of offers that would be adjusted to an Actionable Subsidy Reference Price dictate wide price gaps. Market participants would be able to estimate this gap with increasing precision as the market dynamics of capacity repricing became better understood. Due to these flawed dynamics of capacity repricing, over time prices across the PJM region would approach net CONE*B, the capacity offer cap. Thus, in the name of greater competition, PJM's proposal ironically would move the market toward an arbitrary, administratively-set price. Even in the immediate term, price impacts would severely harm customers. For example, assuming 9,000 MW of repriced resources (an amount less than the amount of targeted resources expected by 2020-2025, as identified by PJM affiant Dr. Anthony Giacomoni), Wilson calculates that clearing prices could increase 50 percent as compared to operation of the PJM capacity market under status quo rules. That would amount to "a total market cost of $9.1 billion" in a single delivery year. Prices would rise even more in the smaller capacity zones. These massive price increases would not provide customers with any appreciable benefits, and would therefore be unjust and unreasonable.
MOPR-Ex forces customers to buy more capacity than needed to provide resource adequacy in PJM. MOPR-Ex, by PJM's own admission, would require customers to procure more capacity than necessary to meet the region's reliability needs.

As PJM explains, "MOPR-Ex almost certainly will result in some duplication of resources needed to serve loads." It does so by adjusting the market offers of resources supported by so-called "actionable subsidies" upward to an administratively determined minimum offer that excludes the resource's revenues from the applicable state program. This will in all likelihood result in the "disqualifying [of] state-subsidized resources . . . from clearing as capacity, and will clear other resources to meet capacity needs."

But because the bulk of state policies affected by MOPR-Ex have been adopted to address the urgent threat of climate change and to reduce dangerous pollution that kills states' citizens, leads to serious health problems, and harms quality of life, states are likely to press ahead with their policies whether or not the affected resources clear in PJM's capacity market, providing additional support to resources if necessary. In PJM's words, "consistent with the state's intent, the subsidized resources will likely remain in service and continue operating in the PJM Region."

In such cases, as PJM explains, "loads will be paying for more resources than it needs."

In addition to harming customers by forcing them to pay more for capacity than necessary, MOPR-Ex would also harm the integrity of the PJM markets. MOPR-Ex's

PJM explains that if a state-sponsored resource "can remain in service without PJM capacity market revenues, then loads bearing the cost of the subsidy will effectively pay twice for the same increment of capacity—once through the PJM capacity market, and once through the subsidy payments." PJM filing at 43.

Id. at 56.

Id. (emphasis in original).

Id. at 57.

Id. at 56.
requirement for customers to procure an amount of capacity well above the region's installed reserve margin will "enable price suppression in the wholesale energy and ancillary services markets."

Greater supply in the energy market than economic conditions would otherwise justify will thus "make it . . . harder for otherwise economic resources to compete in those markets."

This will place a special burden on "renewable and limited-duration resources that rely more heavily on energy market revenues than capacity market revenue."

MOPR-Ex's proposed exemptions for certain state policies do not cure these fundamental flaws. The grandfathering provision for "resources that were 'procured in a program in compliance with a state mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018'" merely delays the unacceptable harms the proposal will have on customers with respect to those policies, while the carve-out for programs that are "competitive and non-discriminatory" according to PJM's judgment is so restrictive that many state-supported renewable resources will fail to qualify despite the legitimacy of the underlying policies.

But were the Commission to order a modified version of the MOPR-Ex that eliminates the RPS Exemption, the harm would be exacerbated further still. This even more extreme application of MOPR would sweep in a set of resources nearly certain to be built (indeed, for many such resources construction may already be underway), and thereby guarantee a substantial amount of duplicative costs and suppressed energy market prices. The elimination of any ability for state
RPS revenues to factor into resource offer prices would further heighten the negative impacts of such a rule on a going-forward basis.

Were the Commission to approve MOPR-Ex or the even more extreme MOPR with no RPS exemption, the Commission rather than the states would be at fault for imposing the costs of unnecessary duplicative capacity on customers. Because the Commission is the entity responsible for setting rates for wholesale interstate capacity sales, it makes little sense to suggest that states have approved unnecessary capacity sales and thereby created the unnecessary costs. Only the Commission can do that.

In regions with capacity markets, the Commission has assumed responsibility to "reflect[] the economic value of capacity reserves" in a manner that is consistent with the region's installed reserve margin. In other words, the Commission's task in regulating capacity markets is to "ensure that there is enough generation to reliably meet load" without "overcharging . . . customers for unnecessary capacity."

While the Commission has reasoned that sloping demand curves may be appropriate due to their ability to induce more efficient pricing than vertical demand curves designed to exactly hit the installed reserve margins, any additional reserves must be procured in a manner consistent with their true value to the system. By entirely ignoring perfectly good capacity, MOPR-Ex would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers would be receiving value for their money. The Federal Power Act's requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

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351 See 103 FERC ¶ 61,201 at PP 35–36 (discussing approval of a sloping demand curve).
Further, as PJM acknowledges, the past, much more limited scope of the MOPR has not presented such a massive risk of resource duplication.

The Commission has never issued an order that so baldly forces customers to pay unnecessary costs and suppresses energy market prices, and the prospect of forcing customers to buy unnecessary capacity is particularly galling in this case given the massive reserve margins in PJM that clearly indicate further measures to increase supply are not necessary. Past decisions focused on deterring the construction or retention of so-called "uneconomic" generation, or preventing states from explicitly adjusting capacity prices after the fact, thereby undermining the Commission's ability to set prices.

As explained in section III.C.3.a, the state programs at issue here entail revenue

PJM filing at 56 ("[D]uplication is limited in today's MOPR, because of its narrow application to only certain gas-fired new entry resources. Consequently, existing resources selected by the state for their environmental attributes (for example) can qualify today as capacity by submitting below-cost, subsidized offers that are not addressed by the current MOPR.").

As explained in Clean Energy Advocates' request for rehearing of the Commission's CASPR Order, that order was unjust and unreasonable because there was no evidence that ISO-NE's mechanism to avoid duplicative capacity payments, the substitution auction, would work. See Docket No. ER18-619, ISO New England Inc., Request for Rehearing of Clean Energy Advocates (Apr. 9, 2018), at 31-34. With MOPR-Ex, no effort at all is made to prevent duplication. Elsewhere, the Commission has sought to avoid forcing to "pay for more resources than are necessary to provide for resource adequacy" or "provide a false signal that new investment is needed when this is not the case." ISO New England Inc. and New England Power Pool Participants Comm., 158 FERC ¶ 61,138 at P 26 (Feb. 3, 2017). By contrast, MOPR-Ex would not even attempt to prevent redundant capacity purchases.

See New England Power Generators Ass'n v. FERC, 757 F.3d 283, 295 (D.C. Cir. 2014) ("LSEs are free to shape their portfolios as they choose, including with new self-supplied resources, 'provided these new resources clear the auction."") (emphasis added)). In fact, the particular buyer-side mitigation rules at issue in that case were designed to "prevent... excess capacity purchase." Id. at 293.

See N.J. Bd. of Pub. Utils. v. FERC, 744 F.3d 74 (3d Cir. 2014); Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1298–99 (2016) (holding that those programs functioned by modifying the capacity prices set by the Commission). In its underlying order, the Commission invited states to seek an exemption from the MOPR where the programs reflected the pursuit of "legitimate policy interests." PJM 2011 MOPR Order at P 143.
from sales of products representing environmental benefits, meaning that offers reflecting such revenue are not “uneconomic.” MOPR-Ex would constitute a drastic and misguided modification to the MOPR that is not supported by past precedent.

The unjust and unreasonable nature of MOPR-Ex is highlighted by comparing it to capacity repricing. While capacity repricing imposes enormous unjustifiable costs on customers, MOPR-Ex would harm customers even more. A rough estimate suggests they could be in the range of $14 to $24.6 billion (more than $200-300 of unjustifiable costs for every customer in the PJM footprint).

These costs would be entirely in excess of those necessary to preserve resource adequacy, and would continue to grow over time with no end in sight (because states will continue to pursue the public interests they are mandated to serve). Further, the inflated resource pool induced by MOPR-Ex would push the energy market to operate in a less and less efficient manner with each successive delivery year.

MOPR-Ex is fundamentally flawed because not only will it induce entry of more resources than warranted, it sets prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM's glut of supply. Structural problems with PJM's market have already encouraged a massive overbuild of the system at great cost to customers, and MOPR-Ex would make that problem far worse, taking the market in exactly the opposite direction from what is necessary.

3. PJM's proposals are not warranted by any market failure

A core principle guiding the Commission's oversight of the wholesale markets is to limit intervention into the competitive markets to the extent needed to address a market failure. Before departing from the norm of allowing market actors to engage in economically rational behavior, see Goggin Affidavit PP 3-4, 15.
the Commission weighs carefully whether such interference is warranted by a clearly identified market failure. This is particularly so where, as here, the market intervention comes with severe costs for the customers the Commission is charged to protect, and tremendous impacts to states, the sovereigns which share oversight over the interconnected electricity delivery system. PJM points to the participation of resources that benefit from revenues from (some, arbitrarily-defined) state programs as warranting intervention, but it is fundamentally wrong to treat value derived from valid state property rights and obligations as "distortions" of the market. PJM is also simply wrong that the participation of resources receiving such revenues will give rise to a threat to reliability that would warrant market intervention; by its very design, market prices will rise if supply becomes low due to retirements (even assuming those retirements are driven by entry of state-supported resources). Nor does the prospect of buyer-side market power warrant tampering with the market here. To the contrary, long-standing Commission precedent holds that the renewable resources that are a primary target of PJM's proposals are an exceedingly poor tool to use in seeking to lower market prices. Moreover, because these state actions are driven by other motivations, there is little deterrence benefit of targeting them for mitigation. Finally, PJM is simply mistaken that the market interventions it proposes will have the benefit of shifting risk from consumers to supply. Its proposals will have precisely the opposite effect. For all these reasons, the Commission should reject PJM's proposals as unwarranted, vastly outweighed by the harms to customer and state interests, and unnecessary to ensure the competition that benefits the public.

A root cause of the unjust and unreasonable nature of both PJM proposals is that PJM has misdiagnosed a problem stemming from state programs that compensate generators for
environmental benefits when in fact none exists. The state climate policies it targets are fully consistent with PJM's objective to "ensure continuation of a competitive capacity market."

Efficient market rules would allow state-sponsored resources to make economically rational capacity market offers based on the revenues they earn pursuant to state policies. Allowing this behavior is the competitive approach because it honors the rights and obligations created pursuant to state law.

While treating state property rights like any other legal obligations would be the correct approach even were the Commission the nation's sole energy regulator, the Federal Power Act's "collaborative federalism" approach that "envisions a federal-state relationship marked by interdependence" further strengthens the logic behind doing so.

As Robert Gramlich, a former PJM economist and adviser to Chairman Pat Wood III, explains, the Commission's general practice since the inception of PJM's markets has been to allow revenues and costs stemming from public policies to affect offer prices. The Commission's role is to regulate for just and reasonable rates when accounting for exogenous market inputs, not in spite of them.

In a past order addressing PJM's capacity market rules, for instance, the Commission explicitly directed PJM to provide for the costs of state environmental policies. Revenue from state climate policies is no different from values afforded by any state property or other legal regime.

Hughes, 136 S. Ct. at 1300 (Sotomayor, J., concurring).
regulations to be reflected in capacity market offer prices.

Similarly, NYISO's tariff includes within going-forward costs "the costs . . . necessary to comply with federal or state environmental . . . requirements that must be met in order to supply Installed Capacity."

The fact that the state climate regulations at issue in this case create revenues rather than costs does not make those economic consequences any less real. As the Commission explained in the context of demand response resources, offers from resources that also earned revenue under state retail demand response programs did not present a risk of "artificial price suppression."

Among the many reasons such a risk was not present was that such state program revenues "are actually for providing services that are separate and distinct from the payments that [such demand response resources] receive for participating in NYISO's ICAP market."

In other words, it is perfectly legitimate for revenue streams from sales of state-defined products to be reflected in offer prices, not a sign of "artificial" suppression.

As PJM explains, where a state regulation limits a unit's run time, that creates an opportunity cost because operation in any given hour may entail "giving up revenue that it could earn if it was running at a more profitable time of the year." PJM Interconnection, L.L.C., A Review of Generation Compensation and Cost Elements in the PJM Markets, at 15 (2009), available at https://perma.cc/BMV7-5QNL. Faulting PJM for not "clearly and explicitly provid[ing] for the inclusion of opportunity costs, especially for energy and environmentally-limited resources" (resources whose run time is limited by state or federal environmental regulations) in resources' default bids, the Commission ordered PJM to revise its mitigation rules to do so.

NYISO Market Administration and Control Services Tariff; Attachment H, § 23.2.1.

New York State Pub. Serv. Comm'n et al., 158 FERC ¶ 61,137 at P 33 (Feb. 3, 2017); see also PJM 2006 RPM Settlement Order at P 106 (default bids under MOPR should allow for recovery of investment costs to meet mandated environmental requirements); PJM 2007 RPM Settlement Rehearing Order at P 150 (customer is not to be shielded from costs of supply to comply with environmental mandates).

New York State Pub. Serv. Comm'n et al., 158 FERC ¶ 61,137 at P 33.

Consistent with the principle that such revenues should be included in NYISO's assessment of unit costs, the NYISO market monitor does include revenues from sales of credits compensating environmental benefits in calculating whether a unit should be...
PJM is wrong that the mere fact that state programs affect wholesale market outcomes means that they are market distorting. PJM presents a highly simplified and flawed example to argue that “the state subsidy program is being underwritten by other participants in the wholesale market.”

But the basis for PJM's conclusion is ultimately only the fact that some market competitors will not clear the capacity market if revenues earned pursuant to a state program are reflected in the offer prices of other resources.

If the simple fact that a state policy impacted market outcomes warranted intervention, the Commission could act to undo the wholesale market effects of any state law of any kind.

The Commission has no role in correcting failures in markets outside its jurisdiction. Under the Federal Power Act, states are expressly permitted to regulate generators for the environmental harms and benefits that they impose upon their citizens. As the United States Supreme Court explained in *FERC v. Electric Power Supply Association*, the Federal Power Act “makes federal and state powers 'complementary' and 'comprehensive,' so that 'there will be no 'gaps' for private interests to subvert the public welfare.'”

Thus, the combined effect of state and federal regulation must be permitted to internalize market externalities where laissez faire exempted under Part B of the mitigation exemption test.

See *New York Pub. Serv. Comm'n et al.*, 153 FERC ¶ 61,022 at P 48 (Oct. 9, 2015) (for renewable resources that are not otherwise exempt from buyer-side mitigation rules, Part B of the mitigation exemption test “takes into account certain incentives for owning renewable resources by reducing the unit-specific Net CONE”).

PJM filing at 32.

See *Gramlich Affidavit* at section IV (“This is a claim about competitors, not competition.”).

Even if the market rules only targeted state laws with large effects on wholesale market outcomes, that would sweep in a wide array of state laws that are well-understood to be beyond the Commission's reach, such as siting requirements, tax codes, and pollution control laws.

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The market operation would harm the public interest. Because the Commission has not assumed the mantle of internalizing these externalities on its own, this dictates that states must be able to do so in a manner that flows through to RTO markets with real economic consequences. Further, internalizing market inefficiencies, as the state policies targeted by PJM do, enhances rather than reduces market efficiency by forcing generation owners to confront the true costs and benefits associated with unit operation.

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It is undeniable that some state policies are inefficient, may wrongly target market behavior that causes, rather than mitigates, externalities, or may otherwise be distortive to the market of the state-regulated product.

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Economists who are fiercely protective of competitive markets may rightly show consternation at the inefficiencies of such policies. This can be particularly tempting where the effects of state policy decisions “flow through” to affect the wholesale markets because of the interconnectedness of the bulk and retail power systems. But it is not the Commission’s job to level the playing field across the state-jurisdictional policies that apply to resources through the wholesale market rules. Rather, the Commission’s responsibility is to correct failures that stem from wholesale market design (i.e. its own market).

Where a state regulates a product such as a REC that is distinct from energy or capacity, or creates a planning obligation consistent with its authority under the Federal Power Act (such as the requirement to ensure a long-term supply of renewable energy), grid operators regulated by the Commission should avoid overstepping their role and simply let those effects flow through the market, consistent with the longstanding Commission policy of allowing for rational

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IPI report at 12-14. Notably, the value of these programs to individual resources, while much criticized by PJM, is in almost every case lower than the social cost of carbon. Thus, an externally objective measure of the appropriate valuation of the public benefit of reducing carbon emissions indicates these policies are welfare-maximizing.

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See, e.g., id. at 17 (highlighting oil and natural gas drilling subsidies).
competitive behaviors by market actors to set supply and demand. The consequence of overstepping, as PJM's proposals demonstrate, is a distortion to the Commission's own markets. As described in Argument Sections III.C.1 and C.2, in this case those distortions would be the unjust inflation of rates (for capacity repricing) or the over-procurement of capacity (MOPR-Ex), and suppressing energy market rates (both proposals).

The specter of reliability crisis because of subsidies does not warrant intervention. PJM urges intervention into the market because "a part subsidized/part competitive market cannot carry out the critical function of ensuring reliability." Setting aside the illogic of adopting drastic market changes to protect resource adequacy in a region where available supply so greatly exceeds the amount necessary to reliably serve customers, PJM's claim would be unsound even in a tightly constrained region. In addition to being premised on the fallacy that state property rights are not "true" supply costs or revenues, PJM ignores that the design of the capacity market will work to avoid such a threat to resource adequacy – even if state policies continue to "escalate."

Given the entrenched and fundamentally unavoidable nature of various types of subsidies, state and federal, that affect PJM's market, it is no surprise that the capacity market is already designed to guarantee reliability whether or not states enact policies. PJM's suggests that the market "will become less sustainable over time, because otherwise efficient, but unsubsidized resources are more likely to be priced out by the subsidized clearing price."
ignores the fact that resources will only be priced out if they are replaced by lower-cost state-sponsored capacity. By design, "the capacity market would react" to the economic effects of state programs. Nor would the presence of state-sponsored capacity prevent the future entry of non-subsidized resources to the extent such resources are necessary. PJM's capacity market demand curve provides that "any decrease in price" that might theoretically be caused by lower offers that reflect state program revenue "can continue only as long as there is a glut in capacity." If supplies ever dip, the market will respond by producing higher prices, sending a signal to market actors to provide adequate supply. This basic market function will continue to operate even, hypothetically, if large percentages of the capacity resources in the market received state support. Historical data demonstrates this to be true, and rebuts PJM's claim that markets with a significant share of subsidized resources are "inherently risky and unstable." The Price-Anderson Nuclear Industries Indemnity Act, for example, provides an extremely valuable limitation on liability that was essential for the entire nuclear generation industry to emerge. In spite of the Act providing the financial support necessary for each nuclear plant to remain in operation over the entire life of the nuclear industry, the wholesale markets appear to be none the worse for wear.

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377 When reflecting state programs, as is appropriate, per the above. To the extent PJM takes issue with the composition of the capacity mix rather than the amount of supply, it is exceeding its role by ignoring valid state property rights.

378 IPI report at 17–18.

379 Id. at 18.

380 Id.

381 PJM filing at 34.

382 Koplow, 1993, at 22, supra n. 140 ("we can conclude that without federal intervention to mitigate long-term, highly uncertain risks, the market would never have developed"). In 1989, the Price-Anderson Act provided around $7.5 to $25 million in value annually to each nuclear generator, which would amount to roughly double that amount in 2017 dollars based on the Consumer Price Index ($14.8M – 49.3M). Id at Appendix B5-5, available at https://www.earthtrack.net/sites/default/files/library/FedSubAppB5.pdf.
worse for the wear. While PJM brushes off this vital, government-provided benefit as "nationwide in scope," it is not at all clear why a policy that benefited nearly a fifth of all generation in 1989, and supports fifteen percent of existing capacity in PJM today, would be less distortive of market outcomes under PJM's theory. Without this shifting of risk to the public, these resources would be forced to exit and would stop "crowding out" new resources seeking to enter.

Finally, because the state policies at issue have been adopted after long regulatory processes and create well-telegraphed consequences far into the future, they are unlikely to have any appreciable effect on market prices. This phenomenon further demonstrates the illogic of PJM's claims that the targeted state policies will affect resource adequacy. As economist James Wilson explains:

When certain additional resources are expected to enter or exit the market (be it "competitive" or sponsored resources), market participants will take these changes into account in planning the timing of retirements, other new entry, and other actions that affect the balance of supply and demand. If the additional resources or retirements are anticipated well in advance, it is reasonable to expect that they are fully anticipated and absorbed by market participants' adjustments, and have minimal, if any, impact on capacity prices.

As evidence from the operation of PJM's markets indicates is occurring, other market actors will adjust their entry and exit decisions in a manner that accounts for the state policies and ultimately cancels out any impacts on capacity market prices that the state policies would have.

This also undercuts PJM's unsubstantiated claim that "subsidies beget subsidies." PJM filing at 34. In spite of the long existence of the Price-Anderson Act, we do not see a proliferation of other limitations on liability among other classes of resource. It is not necessarily the case that subsidies beget further subsidies; some policies focus on achieving a particular benefit that will not be realized without government action.

Based on nuclear generation's share of total energy output among all conventional generators. *Id* at 21.

Wilson Affidavit at P 22.
According to Wilson, "[w]hile the entry of the public policy resources will likely correspond to some delay of other new entry, acceleration of retirements, or adjustments by resources able to enter and exit on a year-by-year basis, this displacement is a natural consequence of the policy, perhaps even an objective of the policy."

PJM provides an affidavit from its director of market operations Adam Keech alleging that state subsidies may have a large effect on market prices, but he ignores this elementary principle that market actors will respond to each other's anticipated actions.

Wilson posits that in theory a "last-minute" state regulation could "catch[] the market totally by surprise," creating the sort of "impacts suggested by Mr. Keech's calculations, for a single auction."

But PJM has not provided any evidence that any of the state programs that its proposals address were promulgated in such a last-minute fashion, or that states are likely to carry out last-minute regulatory actions that cause significant market consequences in the future. In fact, it would be virtually impossible for a state policy supporting renewable resources to have this effect because of the long lead time required to construct these resources.

See id. at PP 20-25, 30 ("The fact that there has been so much entry (and exit) through RPM over the past several years, while RPM prices have remained in roughly the $70 to $170/MW-day range, reflects the dynamic – market participants are adjusting their entry and exit timing based on anticipated market supply/demand balance and resulting prices.

Id. at P 24.

See PJM filing, Keech Affidavit at PP 10–15; Wilson Affidavit at PP 20-33 (describing the many analytical flaws in Keech's analysis).

Wilson Affidavit at P 29.

PJM 2011 MOPR Order at P 155 ("A long lead time resource must necessarily begin construction and incurring the associated costs in advance - and often several years in advance - of the first capacity auction in which it participates."). Moreover, the long-planned procurements of renewable resources under RPS programs are projected years in advance by laws or administrative actions.
PJM's markets would self-adjust in subsequent delivery years, such that in the long term even a policy enacted at the last moment would have no deleterious impact on reliability. Empirical evidence shows the validity of Wilson, and the Institute for Policy Integrity's conclusions that reflection of state-created revenue streams in capacity market offers will not cause a resource adequacy problem, while demonstrating that PJM's theoretically unsound predictions of price suppression and declining entry do not bear out.

Despite having been affected by all manner of external subsidies since its inception, and despite the lack of any drastic market rules such as capacity repricing or MOPR-Ex to control this spread or its effect on the PJM market, PJM can still today tout how the market's "robust competition" has produced "very robust reserve margins."

c. There is no threat of buyer-side market power to warrant market intervention, particularly from state RPS resources. PJM's filing makes plain that it is not concerned with the exercise of buyer-side market power. Its capacity repricing proposal would eliminate the MOPR (including its application to entities with buyer-side market power), while MOPR-Ex focuses "only" on "resources that are receiving a Material Subsidy." As such, it would abandon the Commission's long focus on entities whose exercise of buyer-side market power could be deterred by such rules, extending their scope to some who clearly lack such power while relaxing coverage of others that do. As explained above, revenues earned pursuant to state programs, like any other valid property right,
are appropriately reflected in offer prices, meaning that low-cost offers from resources enabled by such policies would present no risk of artificially suppressing prices, even if the owner possessed buyer-side market power. But even if one discounts such state revenues as invalid, Commission precedent makes clear that renewable resources pose little risk warranting mitigation due to their particular technological and cost characteristics, reasoning that applies regardless of the support provided by state policies.

By targeting renewable and demand response resources for repricing or mitigation for the first time in the region, PJM proposes to break sharply from past Commission practice without any valid theoretical or empirical basis for doing so. The more extreme version of MOPR-Ex that eliminates the RPS exemption entirely would constitute an even greater departure from rational economic principles and Commission precedent.

As the Commission explained recently to the federal courts, PJM's buyer-side mitigation rules were "designed to prevent the exercise of monopsony power," i.e., "to identify new resources with the incentive and ability to depress auction clearing prices." The Commission further described that most recently approved exemptions to the PJM mitigation rule "were appropriately designed to identify new entry that would lack incentives to suppress market prices." The Commission thus has long tailored application of mitigation rules in PJM to target resources that pose a real risk of exercising buyer market power, because they possess both the incentive and ability to benefit by lowering their bids.


398 Id. at *19 (reflecting a judgment that the goal of preventing price suppression should be balanced against the risk of over-mitigation).

399 See supra Background Section II.
In upholding a complete MOPR exemption for renewable resources in PJM, the Commission found "persuasive PJM's justification" that "wind and solar resources are a poor choice if a developer's primary purpose is to suppress capacity market prices" due to their relatively lower capacity factors, variable output, and long lead time (which renders artificial price suppression near impossible because "a reasonable offer" would be substantially lower than that of the offer that sets clearing price due to the resource's low net avoidable incremental costs at the time it enters the auction).

The Commission's reasoning in the case would apply with the same force to resources developed under state RPS programs. Even if one wrongly concludes that it is inappropriate to reflect RPS revenues in a resource's offer, such resources would remain an ineffective means to exercise buyer-market power.

Similarly, the Commission found it unjust and unreasonable to apply buyer-side mitigation rules to demand response resources participating in NYISO's Special Case Resources program because such resources have "limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices."

The Commission had several

PJM 2011 MOPR Order at PP 153-155. We note that neither the Actionable Subsidy Reference Price used for purposes PJM's capacity repricing proposal nor the unit-specific exemption used for purposes of PJM's MOPR-Ex proposal reflects the low net incremental avoidable costs of renewable resources consistent with their long lead time to construct.

See PJM filing, proposed PJM Tariff, Attachment DD § 5.14(j)(4) (Option A) (describing the process for determining a resource's Actionable Subsidy Reference Price, which provides that a resource's *full* construction costs must be taken into account with "no sunk costs excluded"); PJM filing at Attachment DD § 5.14(h)(6) (Option B) (describing the unit-specific exemption for MOPR-Ex that entails the inclusion of "all project costs . . . with no sunk costs excluded"). While PJM's practice of excluding sunk costs for natural gas resources that were previously the only potential target of the MOPR may have been a reasonable measure to prevent market gaming given the feasibility of doing nearly all construction of a gas unit after securing a capacity commitment, that practice is not rationally extended to renewable resources with longer lead times and is therefore unjust and unreasonable.

reasons to justify this conclusion, including the fact that the demand response resources, “which are generally individual or small aggregated sets of ‘resources’” did not “have the same ability to suppress ICAP market prices as a single, large market participant,” making them “an unlikely source to either have or exercise buyer-side market power.”

In making an about face to apply MOPR to renewables and demand response resources, PJM does not provide any evidence to rebut the conclusions that these resources are poor tools of price suppression, or explain why the Commission’s previous reasoning is not persuasive.

d. PJM’s proposal shifts regulatory risk from generators to customers

PJM claims that its proposals help to address the shift in risk from private capital to customers caused by price suppression from state subsidies, suggesting another potential basis for Commission intervention into the markets.

In fact, the opposite is true: PJM’s proposals would insulate supply from regulatory risk by placing that risk on customers.

PJM makes no effort to actually show that the policies it targets transfer risk to customers, and state renewable policies and demand response programs do not in fact do so. It is not correct that the sale of RECs shifts the financial risks of operation onto customers. Precise revenues from RECs are not guaranteed to all eligible renewable resources under a state program; competition for RECs drives their price down and brings the same incentive to innovate as other forms of competition. Where eligible resources secure long-term power purchase agreements pursuant to state programs, these are often the result of winning
competitive solicitations.

Moreover, such power purchase agreements can offer both retail consumers and the supplier value as a price hedge. One cannot categorically conclude such financial instruments are adverse to consumer interests.

State demand response programs generally compensate resources for services provided to the distribution system, and are not a risk transferring tool of any kind. In contrast, PJM's proposals protect supply from regulatory risk that could result in their being priced out of the market. As economist Gramlich explains, under normal competitive wholesale market principles, "[r]isks of public policy changes are borne by investors." Just like "[a]ny product subject to health, environmental, safety, or other forms of regulation," where "[p]roduct prices and stock values are changed every day" due to such regulations, electricity


PJM Resource Investment Whitepaper at 45.

See id. at 28 (describing how capacity market fails to provide a long-term price hedge and expressing expectation market participants would eventually use bilateral contracts to address those risks).

Even in a case in which an RPS program did result in some shifting of risk from supply to consumers, these risks fall on retail customers. At the wholesale level, customers simply see the effects of these policies as reducing the cost of capacity, not as increased financial risk.

Gramlich Affidavit at section VIII.
investors could see their bottom line impacted by regulatory action. But under PJM's proposals, and MOPR-Ex in particular, incumbent generators have the assurance that the effects of certain state policies on their bottom line will be mitigated. That confidence comes at a high cost to customers, who pay price premiums to ensure the incumbent technologies meet their revenue expectations in the face of shifting policy preferences. But ultimately the right outcome is that supply should bear the consequences of the state authority's determination of the public interest on matters outside the Commission's jurisdiction: it is not the Commission's charge to protect particular competitors from adverse regulatory consequences of legitimate state policies.

D. PJM's proposals are not just and reasonable because they increase market uncertainty

The Commission must also reject PJM's proposals because they would unreasonably undermine market certainty. The Commission has long-recognized the importance of clear and objective tariff provisions, particularly in applying mitigation measures, to provide needed certainty to all participants.

PJM's proposals, of which the lynchpin of each is a subjective and internally inconsistent standard, will only produce greater dispute, litigation, further rule changes, and market uncertainty going forward. Building a capacity market based on the scope of a "subsidy," which by its very nature is a subjective term, will doom the market rules to swing in direction dramatically as the political environment shifts, the nature of state actions changes and impacts different sets of market actors, and as the composition of the Commission changes.

Id. at section IV. PJM 2009 RPM Order at P 190; PJM 2007 RPM Settlement Rehearing Order at P 180; PJM 2011 MOPR Order at P 120.
over time. This is not a recipe for enhancing the certainty market participants will need in the face of economic and technological changes that will continue to shape the energy sector. Moreover, other aspects of the proposals also threaten market certainty unnecessarily. The scope of the MOPR exemptions are confusing and do not provide clear guidance as to which state policies will be covered. This undercuts investor certainty. Placing PJM and the IMM in the role of determining the scope of an actionable subsidy is likely to be unworkable, and lead to long, irresolvable disputes. Finally, both proposals lead to market distortions that will create increasing pressure to once again change RPM market rules to correct course.

1. The proposals' subjective standard leads to uncertainty

As described at length above, the energy sector is pervasively and fundamentally shaped by national, state, and local preferences. Energy sector policy objectives are inextricably intertwined with economic development objectives; health and safety concerns; national security and trade interests; environmental goals; and other critical public priorities. It is not realistically feasible to unwind the impacts of these policy priorities on the competitive wholesale markets. Yet that is precisely the task PJM takes upon itself, by proposing a market design that hinges on the definition of a subsidy. PJM, and the Commission as the ultimate arbiter, will face an unending series of disputes as a result. Under MOPR-Ex, market participants that may benefit from a broad definition of a subsidy because it results in the mitigation of a competing resource will push the definition to the limits. As discussed above, while PJM focuses on the alleged impacts of ZEC and RPS programs, there are numerous forms of government incentive that, either singly or collectively, will objectively meet PJM's thresholds to be treated as an actionable subsidy. If PJM does not agree to these broader applications readily, litigation may well follow. Moreover, to the extent that it appears that PJM and IMM will each share some role in interpreting the tariff language, a real prospect of diverging interpretations of the subjective
The unworkability of PJM’s definition may well create the impetus for further changes to the market construct’s threshold definitions. None of this uncertainty surrounding the ultimate scope of resources that will be deemed subject to “actionable subsidies” is helpful to settling investor expectations or market certainty.

2. The scope of the RPS exemption is unclear and further clouds market expectations. Uncertainty surrounding the scope resources that receive “subsidies” is only exacerbated by further ambiguity surrounding the scope of the exemptions to that definition. In particular, there is significant uncertainty regarding the application of the RPS Exemption to MOPR-Ex. PJM asserts that its proposed RPS Exemption is “broadly stated and accommodate[s] most state RPS programs.” Our own assessment, set forth in detail in Appendix A, “Analysis of MOPR-Ex RPS Exemption,” raises serious questions about the claim. Of the eleven RPS programs within the PJM footprint, there is significant lack of clarity as to the eligibility of ten of the programs. Many of the exception criteria are susceptible to more than one interpretation. A broad reading, consistent with the IMM’s representations during the stakeholder process, would appropriately ensure coverage of many of these programs. Absent binding representations from PJM, states and other market participants have no certainty regarding the future treatment (post-grandfathering) of RPS resources under the exception. This puts the disposition of a significant quantity of capacity to be procured, with targets ranging from 10 to 30% or more of retail sales, under a cloud of uncertainty. Not only does this uncertainty increase market risk and hamper market decisions, it also has more immediate negative impacts. Renewable developers will factor...
into the bids the administrative burden associated with seeking an exemption and the risk that they will not be able to obtain capacity market revenues. This in turn will raise the cost to states of meeting RPS targets.

3. Market distortions that result from PJM's proposals will force further rule changes. Both the capacity repricing and MOPR-Ex proposals produce market distortions that will escalate over time, become increasingly burdensome and unmanageable, and ultimately create increasing pressure for further rule changes – and thus, more uncertainty. MOPR-Ex will increasingly result in mitigated capacity resources sitting on the sidelines, while requiring loads-serving entities to procure larger and larger quantities of duplicative capacity. This will particularly be the case in light of the steadily more ambitious RPS targets adopted by states in response to the urgent threat of climate change rather than a desire to suppress prices and will not be readily deterred by the threat of possible mitigation (which remains uncertain for many resources given the ambiguous scope of the RPS exception). Forcing customers to pay significantly to procure more capacity even as capacity surpluses artificially persist and increase as a result of PJM's policy will become, at a point, untenable.

Capacity repricing, as described above, leads to perverse bidding incentives (the "race to the bottom" and "clear out the top") that will result in increasing price distortion over time. Wilson describes the phenomenon at length:

Thus, it should be expected that year to year, the distortion of offer prices would only increase. As a result of these incentives and resulting rational conduct, the RPM supply curves will become steeper and steeper over time. This is exactly the opposite of the result that is desired – gently sloped supply curves lead to competitive outcomes and relatively stable capacity prices over time, resulting in stronger investment incentives and weaker incentives to exercise market power.
Steeper supply curves lead to more volatile prices, greater incentives to physically or economically withhold, and weaker incentives for investors. This downward spiral toward ever greater price distortion, too, is not sustainable. Market participants, having adjusted to yet another new, complex capacity market construct, will face uncertainty anew as market rules are revisited once again.

CONCLUSION

For the foregoing reasons, the Commission must reject PJM’s filing.

Respectfully submitted,

[signatures to follow]

Wilson Affidavit PP 70-71.
CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.

Dated at Washington, D.C. this 7th day of May, 2018.

/s/
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APPENDIX A: Analysis of MOPR-Ex RPS Exemption

A. Description of PJM's Proposed RPS Exemption

The first portion of the RPS Exemption covers "Capacity Resource[s] ... procure[d] in a program in compliance with a state-mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018." This grandfathering term is broad and would cover mandatory state renewable portfolio standard programs. It does not cover resources procured pursuant to a voluntary RPS, which would affect resources procured under programs in Virginia and Indiana, as well as during the time that Illinois' program was voluntary.

In contrast, the RPS Exemption language for future procurements or future policies, Attachment DD § 5.14(h)(10)(b), is ambiguous and arguably extremely narrow. The RPS Exemption applies only to resources procured pursuant to an RPS if the entire RPS program meets PJM's specific criteria for a "competitive and non-discriminatory" program. The program may not give any preference, direct or indirect, to new resources over existing resources, or vice versa. (Attachment DD § 5.14(h)(10)(b)(ii)(2), (5), and (6)). Nor may the program grant any preference based on location of the resource, except that imports from other states may be

1 Proposed PJM Tariff, Option B, Attachment DD § 5.14(h)(10)(a) (attached to PJM filing as Attachment D).

2 Subsection (10)(b)(i) provides that "the Capacity Resource complies with the requirements of a state-mandated renewable portfolio standard or voluntary renewable portfolio standard." Subsection (10)(b)(ii) further requires that the terms of that program must be "competitive and non-discriminatory" and enumerates eight factors to be considered in determining whether the entire program qualifies. We therefore read the exemption to exclude from eligibility any resource procured pursuant to a program that does not meet PJM's criteria to be "competitive and non-discriminatory."
restricted (id. § 5.14(h)(10)(b)(ii)(7)). "[T]he requirements of the program" must be "fully objective and transparent." (id. §5.14(h)(10)(b)(ii)(4)). PJM also includes two criteria that could be read to suggest that state programs may not exclude from eligibility or grant preference to any particular renewable energy resource type. Specifically, subsection (b)(ii)(3) states that "all supplies of renewable Capacity Resources may participate," while subsection (b)(ii)(8) states that "the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas, or nuclear thermal resources." While these two terms are susceptible to multiple readings, it is possible that they could be interpreted to exclude any RPS program that excludes certain renewable types from participation in all or part of the procurement. Even if a program is deemed "competitive and nondiscriminatory" based on the criteria in subsection (b)(ii), it must also meet additional standards based on whether it awards credits (1) via auction, with winners determined based on the lowest offer prices, payments based on an auction clearing price, and the participation of at least three non-affiliated sellers; or else (2) in a manner "consistent with fair market value and standard industry practice and . . . provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller." (id. § 5.14(h)(10)(b)(iii)-(iv)).

Without even considering the highly subjective and ambiguous "fully objective and transparent" criterion, a state by state analysis of 11 RPS programs in the PJM region revealed significant uncertainty as to eligibility for 10 of the state programs.

3 Most state programs 3 This analysis is intended only to explain the risk that any of these state programs may not be deemed eligible for the RPS Exemption, and should not be construed as a statement on the part of any of the undersigned organizations that we believe the program will in fact be determined to be ineligible.
contain preferences among resource types, or exclude certain types of resources that may be considered "renewable" but have other adverse effects the state wishes to avoid incenting. The analysis below focuses primarily on whether state RPS programs meet the criteria in subsection (b)(ii). The ten state programs that we conclude face significant doubts as to their eligibility for the exemption run into trouble before even reaching the last two parts of the exemption, which constrain the manner in which auctions can be conducted. These auction provisions, as described above, add even greater ambiguity to the viability of capacity offered based on most state programs. Auction is undefined and therefore it is unclear whether a procurement based on requests for proposals, a common structure, qualifies as an "auction" and is subject to the criteria in subsection (b)(iv), or to those in subsection (b)(iii). The restrictive means by which such auctions must proceed also prevent LSEs or state procurement agencies from considering any factor other than price in selecting the winner of the auction, contrary to the more holistic review of bids that is typically part of an RFP process. The minimum number of participating sellers also makes it impossible to assess, ex ante, whether a resource that wins the auction will in fact qualify for the RPS exemption (assuming the auction and RPS policy it implements have cleared all the other barriers).

B. State-by-State Analysis

This section provides basic, limited descriptions of renewable portfolio programs in states within PJM, focusing on program elements that are relevant to the RPS Exemption. Because PJM has provided so little in the way of interpretative materials regarding the ambiguous language in this exemption, the analysis that follows assumes a narrow application of the exemption's criteria. This analysis is intended only to explain the risk that any of these state programs may not be deemed eligible for the RPS Exemption, and should not be construed as a statement on the part of any of the undersigned organizations that we believe the program...
will in fact be determined to be ineligible. Should PJM or any other entity with a role in implementation believe that the following analysis is erroneous or misinterprets the scope of the exemption, a binding explanation of that entity's interpretation should be published.

1. Delaware Delaware's Renewable Energy Portfolio Standard, 26 Del. C. § 351 - § 364, was first enacted in 2005. It sets a portfolio target of 25% renewable by 2025-2026, and requires that 3.5% of the portfolio comprise solar resources.

4. Certain renewable resources are not eligible, including hydroelectric power over 30 MW, and biomass that is not cultivated and harvested in a sustainable manner as determined by the state natural resource agency.

5. Landfill gas facilities installed after January 1, 2004 must meet more stringent emission requirements to be eligible. The law allows credit multipliers based on various geographic criteria, such as for in-state customer-sited solar photovoltaic systems and fuel cells, in-state wind turbines, and projects that are sited and a certain percentage of components were manufactured in Delaware.

6. Given that Delaware's targets are set for 2025-2026, over five years of procurement under this policy would not be grandfathered. The law contains preferences for different renewable resource types through both the solar carve-out and exclusions for various renewable resource types with adverse non-energy environmental impacts, potentially conflicting with the requirements in subsections (b)(ii)(3) and (8), and provides additional incentives for projects with a certain percentage of components manufactured in state, which is either an impermissible locational requirement ((b)(ii)(7)), or runs afoul of the restriction on considering factors other than price when selecting resources for the portfolio ((b)(iv)). Newer landfill gas facilities must...
meet different emission requirements than older ones to be an eligible resource, potentially running afoul of (b)(ii)(5).

2. District of Columbia

The District of Columbia's Renewable Portfolio Standard, D.C. Code §34-1431 et seq., was enacted in 2005 and sets targets of 20% by 2020 and 50% by 2032. The law specifically requires that 2.5% of the portfolio consist of solar resources by 2023. Substantial procurement remains under the District of Columbia RPS to meet the 2020 and 2050 targets, as the 2018 target is just over 15%. The solar carve-out in the policy potentially runs afoul of (b)(ii)(3) and (8). The structure of the RPS Exemption makes a resource eligible only if the RPS programs meet all of the criteria in subpart (b)(ii); therefore, if an RPS program does not meet those criteria, the RPS Exemption would not apply to any resource procured pursuant to that program, even resources procured for the portion of the portfolio requirement not subject to the carve-out.

3. Indiana

Indiana's voluntary Clean Energy Portfolio Goal was enacted in 2011, and establishes a target of 10% by 2025. Certain fossil-fuel based technologies are qualifying resources under the statute, including nuclear, "clean coal," and "electricity that is generated from natural gas at a facility constructed in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." Because Indiana's RPS includes nuclear and fossil-fueled resources, it is not a qualifying program under (b)(ii)(8), so even renewable energy resources procured through the program would be ineligible for the RPS Exemption.

7 D.C. Code §34-1432(c)(10), (c)(22).
8 Id. §34-1432(c)(13).
9 Id. §34-1432(c)(8).
10 Ind. Code § 8-1-37.
11 Id. § 8-1-37-12(a)(3).
12 Id. § 8-1-37-4(a)(17), (a)(18), (a)(21).
Illinois' Renewable Portfolio Standard was enacted as a voluntary program in 2001, converted to a standard in 2007, and further modified in 2016. Both electric utilities and alternate retail electric suppliers (ARES) are required to meet portfolio targets of 25% by 2025, but are subject to different subsidiary requirements. Electric utilities are required to meet 75% of their portfolio using wind and solar resources, whereas the equivalent requirement for ARES is 60%. Electric utilities are also required to meet a percentage of their renewable portfolio with distributed energy resources, which are those less than 2 MW in capacity, interconnected to the distribution system and used primarily to offset a customer's load. New hydropower is ineligible. The 2016 amendments to the RPS (the Future Energy Jobs Act), requires the Illinois Power Agency, which administers the RPS, to procure various quantities of generation from new renewable energy resources over time. Any resources procured during the time Illinois' RPS was voluntary (2001-2007) would be ineligible for the RPS Exemption for grandfathered resources, which only applies to resources procured pursuant to mandatory RPS programs. Any resources procured pursuant to the RPS between now and 2025 may also be ineligible for the RPS Exemption because the Illinois RPS has several disqualifying factors. First, it gives preference to certain types
renewable resources, contrary to the requirement in (b)(ii)(3) and (8). Second, the Illinois program gives a preference to existing hydropower over new hydropower, and requires procurement of new wind and solar resources, contrary to (b)(ii)(2) and (6). Finally, the distributed generation requirement could be interpreted as a locational restriction, contrary to (b)(ii)(7).

The Illinois RPS requires the Illinois Power Agency to run competitive procurement processes that eventually results in power purchase agreements between suppliers and utilities. It is unclear whether these application- and bid-driven procurement processes amount to an "auction" and therefore, whether subparts (b)(iii) or (b)(iv) further governs the eligibility of resources procured pursuant to this state program. If (b)(iv) were to apply to the Illinois procurement process, then Illinois' requirement that contract prices be "cost effective" would disqualify the program based on the (b)(iv) requirement that "payments to winners [be] based on auction clearing price."

5. Maryland

Maryland's Renewable Energy Portfolio Standard was first enacted in 2004 and subsequently revised in 2006. The law sets a target of 25% by 2020, and requires that 2.5% be met by solar resources. In 2013, the legislature revised the standard to impose a carve-out for offshore wind, in an amount to be determined by the Maryland Public Service Commission, but in no case more than 2.5%. Only resources within PJM are eligible.

21 Id. §3855/1-75(c)(1)(D).
24 Id.; see also http://programs.dsireusa.org/system/program/detail/1085.
The offshore wind and solar carve-outs in the Maryland RPS would most likely disqualify all resources procured under that program, as those carve-outs constitute forbidden locational preferences ((b)(ii)(7) and differentiation among renewable resource types ((b)(ii)(3), (8)), respectively. In addition, the mechanism through which the Maryland Public Service Commission considers and awards contracts for offshore wind projects may be viewed by PJM or the Independent Market Monitor as insufficiently competitive to qualify for the exemption. In spring 2017, the Maryland PSC agreed to grant offshore wind renewable energy credits to two offshore wind projects totaling 368 MW (nameplate) in a proceeding that only involved two competing applicants, but subsection (b)(iv)(3) requires a minimum of three bidders in any "auction-type" process to be competitive. Although these two offshore wind projects would likely be eligible for the RPS Exemption under section 10(a), it is possible that future offshore wind procurements by the Maryland PSC will also have a small number of bidders, given that the very purpose of the Maryland Offshore Wind Energy Act of 2013 is to promote the development of a nascent industry in the United States.

6. Michigan

The Michigan Renewable Energy Standard was first enacted in 2008 and updated in 2016. It establishes a standard of 15% by 2021, with a goal of 35% of electric needs "met through a combination of energy waste reduction and renewable energy by 2025." Some


27 See H.B. 266 (2013).

28 Act 295 of 2008; Senate Bill 438/Act 342 of 2016; MCL 460.1001 et seq.

29 MCL 460.1028(1)(c).

30 Id. 460.1001(3).
portion of these targets can be met with Advanced Cleaner Energy Credits ("ACECs"), which can be generated by gas- or coal-fired technologies with significantly reduced carbon dioxide emissions.

31 The Michigan statute awards various credit multipliers for renewable generation from existing solar, generation at peak load times, generation used to charge storage systems later discharged at peak times, and from resources constructed using a Michigan workforce.

32 A final relevant program element is that renewable energy credits can be obtained from out of state resources, but only if they are located "in the retail electric customer service territory of any provider."

33 The Michigan Renewable Energy Standard has several criteria that may render resources procured pursuant to it to be ineligible for the RPS Exemption. First, resources relying on natural gas and coal as fuels are eligible for some portion of a utility's RPS obligation, in conflict with (b)(ii)(8). Second, the credit multiplier for certain existing solar resources conflicts with subsection (b)(ii)(5) which excludes policies granting preferences to either new or existing resources. The program also includes a locational restriction in conflict with subsection (b)(ii)(7), by making out of state resources eligible only if they are in the service territory of a utility subject to the law.

7. New Jersey The New Jersey Renewables Portfolio Standard was originally enacted in 1999 and has been updated several times.

34 S.B. 2936 (included distributed generation to produce RECs/SRECs) (2007); A.B. 3520 (included solar specific provisions) (2010); S.B. 1925 (includes low-impact hydro facilities less than 3 MW as Class I) (2012) (included offshore wind provisions) (2010);
for solar resources that includes a 2028 solar portfolio standard of 4.1%. Hydro-electric resources built prior to 2012 are not eligible.

The New Jersey Assembly and Senate recently approved legislation to increase its renewable energy mandates, create energy storage goals, and provide subsidies to the state's aging nuclear power plants. A law increases the state's RPS to 50% by 2030 and requires generators to source an increasing amount of their electricity from behind-the-meter solar, to reach 5.1% by 2021. That legislation has not been signed by the governor at this time these comments are filed.

The Offshore Wind Economic Development Act of 2010 requires that each electric power supplier and each utility meet a portfolio target for offshore wind energy, amounting to 1.1 GW of offshore wind projects. The Board of Public Utilities (BPU) has sole jurisdiction to approve an offshore wind renewable energy certificate (OREC) price that will allow an applicant to satisfy the cost-benefit standard set forth in the statute. Governor Phil Murphy recently issued an executive order "directing the [NJBPU] to fully implement the Offshore Wind Economic Development Act (OWEDA) and begin the process of moving the state toward a goal of 3,500 megawatts of offshore wind energy generation by the year 2030."


Like many of the other state RPS policies described here, New Jersey's RPS includes a carve-out for solar resources, rendering any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8). New Jersey's RPS also includes a carve-out for offshore wind energy, in conflict with the prohibition of locational restrictions in subsection (b)(ii)(7). Furthermore, assuming that the OWEDA procurement mechanism is deemed to be an auction, then the price paid for the resources must be determined by the auction clearing price; by contrast, New Jersey law calls for the OREC price to be administratively determined by the NJBPU at a level "which will achieve the purposes of the Act at the least cost to ratepayers."

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43 Id. at §62-133.8(d) – (f).

eligible, and a small solar carve-out. Resources eligible for the second tier include waste coal and integrated combined coal gasification technology.

The Pennsylvania Alternative Energy Portfolio Standard has several criteria that may render resources procured pursuant to it ineligible for the RPS Exemption. First, resources relying on coal as fuels are eligible for some portion of a utility's RPS obligation, in conflict with (b)(ii)(8). Second, the solar carve-out renders any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8).

Virginia
The Virginia Voluntary Renewable Energy Portfolio Goal was enacted in 2007 and establishes a target of 15% by 2025, and a cap of 20%.

Because Virginia's policy is voluntary, none of the resources already procured under this program would be grandfathered under section 10(a) of the proposed RPS exemption. The program does not appear to have any potentially disqualifying factors for any future procurements.
In 2008, Ohio enacted its Alternative Energy Portfolio Standard (AEPS), as part of broader restructuring legislation, establishing a renewable portfolio standard of 12.5% by 2025, including a small solar carve-out. The initial standard also imposed a separate 12.5% target that could be met with either renewable energy or "any new, retrofitted, refueled, or repowered generating facility located in Ohio." In 2014, Ohio froze the AEPS compliance schedule for two years and removed the separate requirement for fossil-fuel related alternative energy sources. The current standard requires 12.5% renewable energy and 0.5% solar energy by 2026. The solar carve-out in Ohio's AEPS renders any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8). Moreover, it is possible that renewable energy resources procured during the time the AEPS also required procurement of fossil-fuel related alternative energy resource could be excluded from the grandfathering protection of subsection 10(a) because the RPS program would have, at that time, be in conflict with subsection (b)(ii)(8).

Revised Code Section 4928.64; http://programs.dsireusa.org/system/program/detail/2934.
Appendix B – Expert Affidavits and Reports
Koplow Report
Energy Subsidies within PJM:
A Review of Key Issues in Light of Capacity Repricing and MOPR-Ex Proposals

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Prepared for:

Sierra Club

May 7, 2018
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1. Introduction

This paper evaluates a proposal by PJM Interconnection to address certain state subsidies that it contends harm the competitiveness of capacity auctions within its territory. Subsidies, whether through state, federal, or local policies, are pervasive in the energy sector. This paper assesses PJM’s proposed method for screening actionable subsidies in the context of an extensive literature on energy-sector subsidization to highlight ways in which their approach fails to address subsidies in a neutral manner.

In an April 9, 2018 filing submitted to the Federal Energy Regulatory Commission (FERC), PJM proposed two mutually exclusive options to protect capacity auctions from the impacts of these subsidies.\(^1\) *Capacity repricing* would increase the market clearing capacity price paid to all bidders that clear by adjusting bids to account for subsidies received by certain generators, though would not alter which specific bidders cleared. A second option, *MOPR-Ex* would adjust the bid price for subsidized resources prior to evaluating their competitiveness, changing the mix of facilities that would clear the capacity auction. PJM believes the first option would be more accommodative to allowing state preferences and goals within the power sector to continue to survive in the market place.

PJM’s filing describes the types of subsidies that would be “actionable” under its proposals, including policy types, materiality, and exclusions. In doing so, PJM embarks upon a challenging task: subsidies flow to all forms of generation, and nearly every upstream and downstream stage of each power-related fuel cycle as well. Moreover, focusing only on currently-active supports ignores the fact that historic subsidies may have underwritten long-lived capital investments that remain in place, even if the subsidies themselves have been reduced or eliminated. These older policies may thereby have the same type of market effect as current subsidies: allowing affected units to offer in at lower prices than otherwise would have been possible. Further, gaps either in PJM’s definition of actionable subsidies, or in the data needed to quantify actionable interventions, may result in material interventions being ignored. Finally, equity issues may arise where units reliant on subsidies that pre-date the inception of capacity markets are suddenly being penalized for them and potentially forced out of the marketplace.

PJM’s description of which subsidies are actionable initially seems broad enough to capture most types of potential subsidy. However, exclusions added just a few paragraphs later winnow down coverage in ways that are likely both material and unequal in how they affect different fuel cycles. Even if the wording suggests particular subsidies should be included for review, how PJM interprets these definitions in practice remains unknown. The particular subset of actionable subsidies that PJM highlighted in its April filing was quite narrow and ignores many subsidies that affect the market in similar ways (PJM 2018; Giacomoni 2018).

PJM’s listed examples consist almost exclusively of “purchase mandates,” which are statutory targets for consumption of particular forms of power that must be met within a geographic region even at above-market prices. Most commonly, these take form of renewable portfolio standards, tradeable renewable energy credits, and newer zero emission credits that attempt to protect incumbent nuclear generators.

But many subsidies that affect energy production decisions do not fall into this category; rather, the most important subsidy mechanisms can vary widely by energy type. As a result, if there are data gaps related to particular policy types, some fuel cycles may be unaffected while estimates for others are highly inaccurate. There is some predictability to the patterns: capital-intensive generation will be more affected by build times, financing conditions, and changes in demand during the build period. Electricity reliant on high volume flows of input fuels are affected by subsidies to key transport links, favorable policies for pipeline building, and subsidies to extraction. Accordingly, PJM’s focus on one category of subsidies will have the effect of discriminating based on technology type.

More specifically, purchase mandates are very significant for renewable power and increasingly for old nuclear plants as well, though play no role for natural gas. Credit support such as subsidized loans, tax exempt debt, or government guarantees on private borrowing, are important for nuclear power but fairly immaterial for wind and all but the largest centralized solar installations. Liability caps are material primarily for nuclear and oil transport; subsidized state ownership for nuclear (waste management) and large hydroelectric power facilities. Royalty reductions, uncompetitive lease auctions, and subsidies to linking infrastructure (often at both the state and federal levels) bolster fossil fuels but are immaterial for renewables.

This paper provides a brief introduction to the types of subsidies often flowing to energy facilities, and evaluates the planned scope of subsidy review proposed by PJM to identify areas of potential concern. There is no single data source that tracks and values all subsidies flowing to PJM facilities and associated production, and this paper makes no claim to play that role. Rather, by piecing together available data and actual examples, the goal here is to illustrate potential gaps and hidden distortions in the current policy formulation.

Identifying and quantifying relevant subsidies within a short time frame and limited budgets is not easy. Even if bidders are required to submit this information, some ability to validate the data provided will be needed within PJM. Further, because estimates of actionable subsidy magnitude drive bid adjustments that may have large and expensive competitive ramifications, challenges by affected parties would seem likely, further complicating the process.

2. Actionable Subsidies as defined by PJM leave a great deal out

In defining which subsidies would be “actionable” under its proposal, PJM aims to capture key supports that materially reduce the price at which a resource can bid into the capacity auction. The proposal also aims to exclude programs and policies that have a small
effect and won’t alter the clearing price. Using a number of metrics listed below, this paper evaluates whether there are gaps in PJM’s proposed approach and whether those gaps will result in a system that is not neutral across market competitors.

- **Political jurisdiction.** Are there types of governmental entities or levels of government being excluded from review, but that are likely to provide material subsidies?

- **Materiality at plant level.** Do any of the subsidies that PJM’s definition would exclude have material impacts on generator revenue? Is the measurement of subsidy impact on cost structure being done in a neutral way?

- **Intervention type.** Subsidies to PJM market participants take many forms. Some are easy to see and to measure; others are complicated and may be largely missing even from available government data. What are the policy gaps in the PJM proposal, and what type of bias might they introduce? Are there notable differences between available data on state subsidies and the examples included by PJM in its FERC filing?

- **Energy type.** Are subsidies to both incumbents and new entrants being addressed equally? Are particular forms of energy being treated differently? Are subsidies to upstream (extraction, transport) and downstream (facility decommissioning) relevant to the economics of power generation in the region? If so, are they being included?

3. **Systematic exclusion of federal subsidies and many sub-national supports will bias results**

PJM’s definition initially appears fairly inclusive, reflecting any “material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource.” (PJM 2018: 69).

“Any government entity” would seem to include local, state, or federal support, recognizing that it is often the combination of support from these different jurisdictions that tips projects from non-investable to investable; or keeps marginal facilities from shutting down. As PJM Senior Market Strategist Anthony Giacomoni observes, state subsidies generally have the effect of causing certain resources to be viable where they might not otherwise be: (Giacomoni 2018: 6):

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2 Erickson, Downs, Lazarus and Koplow (2017) modeled the effect of state and federal subsidies on 800 US oil fields to evaluate the degree to which they relied on subsidies to hit investment hurdles. Nearly half of the fields were uneconomic at $50 per barrel oil (the price at the time of publication), and the modeling illustrated the importance of not looking at a single subsidy in isolation.
While my affidavit does not attempt to calculate whether each resource that receives a state subsidy would not enter service, or would not remain in service, without the subsidy, it is reasonable to conclude, as a general matter, that these subsidies cause more MWs of the favored resource types to be in service than would be the case without the state subsidies. In other words, without these subsidies from outside the PJM wholesale market, some portion of these subsidized resources would not be economic.

Yet the basic principle he highlights applies to all subsidies, regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted. A large subsidy is likely to distort market behavior, creating winners and losers in the process, regardless of its form. Any system of oversight must be carefully constructed such that the full array of influences is visible, and it is in this context that the many exclusions indicated by PJM must be evaluated.

3.1. Blanket exclusion of federal interventions is unjustified

Federal interventions can be large and targeted. PJM excludes all federal-level subsidies. While it argues that federal subsidies inherently have a broader reach and don’t discriminate based on geography, and therefore are less likely to have a discriminatory impact on the marketplace, that is often not true (PJM 2018, 70, 71).

Although federal subsidies may be open to all states, they can also be both large and highly targeted. The Department of Energy’s Title XVII loan guarantee program, for example, has provided federal credit support on the order of hundreds of millions or billions of dollars to a handful of specific facilities, including power generation. The tenders are somewhat competitive; however, so is state-level bidding for RPS capacity. Title XVII projects often have some technology risks; but so do new offshore wind facilities planned within PJM member states and that are called out specifically as problematic subsidies within PJM’s filing (Giacomoni 2018). Structurally, there is no reason to believe that Title XVII credit subsidies would not affect capacity market bids in a very similar manner as state subsidies.

While a review of DOE’s current loan portfolio (DOE 2018) found no active generation projects within the PJM region (one solar project was discontinued and there are a couple of large loan guarantees to advanced vehicles, another part of the program), it remains possible that loans will be granted under the program in the future. The scale of support under Title XVII can be so large that ignoring its impact on capacity markets simply because the subsidy originated at the federal level seems unsupportable. DOE continues to have open rounds for new lending, so a PJM-based generation project is a real possibility. Subsidized projects in the existing portfolio in nearby states could also sell into the region.

Federal interventions can disproportionately benefit a class of firms. Even where federal spending is not targeted to a single facility, it may support a particular type of generation in a manner that provides a competitive advantage to that class of facilities. Federal support to nuclear power is an example of this. There are fewer than 100 operating reactors in
the US, of which roughly 45 are in the PJM service area (NEI 2017). Federal subsidies are largely additive to state subsidies. Federal tax and insurance subsidies, as well as de facto state ownership of parts of the fuel cycle, all subsidize the operating costs of nuclear plants. This includes plant decommissioning (tax breaks on earnings of Nuclear Decommissioning Trust Funds), insurance against liability for reactor accidents (capped under the Price Anderson Act of 1957), and building and managing a long-term repository for high level nuclear waste (a complicated and complex endeavor that has effectively been nationalized) (Koplow 2011). Even where federal subsidies flow to a much larger set of beneficiaries, such as oil field operators (Erickson, Downs, Lazarus and Koplow 2017), data indicate both that the competitive impacts are significant and that the magnitude of federal subsidies frequently exceeds that of the state support.

**Large new federal subsidy programs could also affect the PJM market.** Finally, the Trump Administration continues to promote one plan after another to use federal leverage and treasure to stem the market-based decline in coal and nuclear. The most recent iteration of this push is to use the Defense Production Act (DPA) to bolster the facilities (Dlouhy and Jacobs 2018). Were the DPA, or any of the other proposals that have been floated, actually to take effect, the use of federal credit, purchasing power, or other support to specific plants would be large. Yet, under the PJM repricing and MOPR-Ex rules as currently proposed, these enormous subsidies would be left unaddressed. This could result in a situation where adjustments were being made to one class of generators (because they rely on state subsidies) but not others (who receive mostly federal support).

### 3.2. Many state and local subsidies would also be ignored by PJM

Subsidies to “incent or promote” either general industrial development in an area or to lure production or jobs from one county or locality to another county or locality are not actionable under PJM’s proposal (PJM 2018, 70). While these types of subsidies are more common at the sub-national level, federal subsidies may also sometimes be designed to trigger development in a particular region (and so would be excluded from consideration under two separate limitations proposed by PJM).

But subsidies deployed for purposes that would be excluded under PJM’s proposed definition are sometimes both very large and narrowly targeted to specific energy assets. These large subsidies to individual facilities would affect the structure of power markets no differently than an energy-related grant of similar size or a targeted tax break. The effect of subsidies on bid prices within PJM capacity markets will depend on the scale of the subsidy, not its justification.

An example from the federal level demonstrates how such subsidies can flow to entities with significant political and economic power. After Hurricane Katrina battered the Gulf Coast in 2005, the US Congress authorized billions of dollars in tax-favored Gulf Opportunity Zone bonds. The bonds were supposed to help rebuild the entire region, though in that region the oil and gas industry is both large and powerful. Within the state of Louisiana, $7.8 billion in
bond capacity was created, of which the oil and gas industry captured 57%. Once joint projects with the sector and related industries were included, their share rose to 65%. Two oil and gas projects received more than $1 billion in bond capacity each (Koplow 2012).

Good Jobs First, a Washington, DC- based organization, has been tabulating government subsidies to specific industrial facilities for many years. Their Subsidy Tracker database compiles information from hundreds of different government agencies around the country. Table A.1 is an extract of subsidies to energy-related activities within PJM states that exceeded $20 million. While the subsidies are both large and targeted, they are often granted under the auspices of regional development or plant location; as a result they would be immediately discarded by PJM. Some examples help illustrate common issues that arise when evaluating power-sector related distortions.

**Coal conversion plants in Kentucky.** Heavily reliant on coal jobs, and facing declining demand in the power sector, Kentucky was looking to diversify one of its core products. Between 2007 and 2011, the state provided large subsidies to five different coal-to-liquids plants. Despite most of these projects stalling out (it’s hard to sell expensive gas from coal when fracked gas from the ground is so cheap), the examples raise a number of relevant issues.

- **Scale.** The multi-year support packages totaled more than $1.1 billion. The support to individual plants was as high as $550 million. These subsidies would be of equal or greater scale to many of the tax expenditures benefitting the sector.

- **Power-sector relevance?** At first glance, these subsidies are to coal, not the power plant – though coal is primarily used to make electricity. Further, these particular facilities were making liquid fuels that mostly were destined for heating and transport applications. So are they irrelevant to PJM power production? If subsidies are small, the likely answer is “yes”. If they are billions of dollars, further evaluation would be needed, as subsidizing the coal ecosystem could have important ancillary benefits for coal-fired power plants. For example, the conversion plants could have kept mines and railroad links open and running at efficient utilization levels, allowing them to continue to serve particular power plants too old to retrofit for a different type of coal or too marginal to incur higher transport costs. For large subsidies, some screening would be warranted before dismissing them as irrelevant.

- **Development or not?** The awarding agency for all of these subsidies was the Kentucky Economic Development Finance Authority. As noted earlier, under PJM’s proposal, subsidies to regional development would be excluded from being actionable. But the specific program was through the Incentives for Energy Independence Act, which in Kentucky is nearly all about coal. The larger subsidies on offer from states often pull from multiple programs run out of multiple state agencies. Functionally, they may span excluded regional development and included oversight or energy-focused missions.

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3 Available at https://www.goodjobsfirst.org/subsidy-tracker.
Some may receive a mix of state and federal support. The lines are often gray, making PJM’s proposed test hard to administer.

**Natural gas infrastructure for Marcellus Shale.** Gas prices in the Marcellus region continue to be significantly lower than the Henry Hub benchmark. At least part of this is due to gas being stranded in the region as surging production ran into limited offtake capacity. Boosting gas exports to other parts of the country, and to the world, would increase the likelihood of prices equalizing across regions. A related issue involves constrained outlets for wet gas in the region.

Are massive subsidies to natural gas infrastructure relevant to consider for PJM capacity markets or not? Natural gas plants are the most significant cause of disruption to incumbent plants within PJM (Jenkins 2018), including reducing the infra-marginal revenues that older nuclear plants can earn to stay afloat. This “missing money” in turn has opened the political spigot for billion dollar bailouts to reactors. To the extent PJM undertakes to address subsidies, PJM should be carefully and systematically evaluating whether subsidies of any type within the natural gas fuel cycle are accelerating or exacerbating the disruption of older baseload generators.

Richard Porter of FTI Consulting in Houston remarked to *Bloomberg* that as natural gas transport stabilizes, producers will have “a surety of market and revenue stability,” as well as additional cash flow to fund exploration programs (Kovski 2017). And while gas prices to electric power may rise, the transport component, which “at times has been as much of a market factor as the value of the gas” should fall (Kovski 2017). Rising demand for Marcellus gas is driven by the power sector. However, increased capacity to process natural gas liquids and to liquefy gas for export will both help to feed continued production as well. The degree to which subsidies to related infrastructure result in more gas, cheaper and more reliable gas to power plants, and a continued undercutting of other capacity supplies is not easy to gauge. But it is reasonable to believe there are relationships, and those need to be explored in more depth.

Some of the subsidies of relevance:

- **Shell Ethane Cracker plant in Pennsylvania.** The facility will add desired capacity to handle natural gas liquids, boosting returns to natural gas fields. Pennsylvania has provided $1.65 billion in tax credits to the facility, the single largest subsidy to the energy sector in PJM identified in the *Subsidy Tracker* Database.

- **Dominion Cove Point Natural Gas Liquefaction facility in Maryland.** An increasing share of Marcellus gas is heading for export, and Cove Point will accelerate this shift. Tax abatements worth about $500 million over 14 years were offered to the plant by the Board of County Commissioners in Calvert County. This is a very large subsidy for a county government. It is also one that has been criticized by some tax experts who argue that much of the infrastructure needed to move in the gas was already on the site, that it will be the only LNG facility on the East Coast, and that the site has prime
access to gas from the Marcellus region. While Dominion threatened to leave absent the tax abatements, the company would have lost a great deal from doing so, these analysts argue, and likely would have stayed even with no subsidy. (Ehrenfreund 2014).

**Build it and they will come: the Appalachian Storage Hub.** As PJM works to ensure competitive transparency among its capacity providers, very large moves by state actors appear to be afoot within the region, with investments approaching $100 billion. This creates a new and difficult set of challenges to protect markets.

On this particular project, a combination of state and local support justified on economic development grounds, subsidy terms hidden in private contracts, federal support, and subsidy targets upstream of power plants are all interventions that would fall into PJM’s exclusions or on which public data would not be available. As a result, all would escape consideration by PJM as actionable subsidies – no matter how large they end up being.

The planned hub will straddle PA, OH, WV, and KY (Horn 2018), all parts of PJM. It is likely to include a mixture of investments, including natural gas liquids storage, a market trading center, feed capabilities into multiple key pipelines, and chemicals production. Some of these may be irrelevant to gas-fired power generation; other assets may be dual use, or create subsidized offtake capacity that allows market-based frackers to boost supply to power markets at an artificially low delivered price. This will be an issue of particular import where the investments are in states – like Pennsylvania – with severance and property tax rates at zero.

The major player at this point is China Energy Investment Corporation (CEIP), a massive state-owned Chinese firm formed from a merger of China Shenhua Group, China’s largest coal producer, and China Guodian Corp, one of its largest utilities. CEIP signed a memorandum of understanding with the State of West Virginia in November 2017 to invest $83.7 billion over 20 years. A first phase plan, with $4 billion in investment, is supposed to take place over the next two years (Smith 2017).

Details of the MOU have not been made public. Multiple Freedom of Information Act requests are pending, but so far have unearthed few details on the scope or magnitude of public subsidy at play on either the Chinese or the US sides of this deal. One detail that has come out is a potential $1.9 billion subsidized loan for the project under the Department of Energy’s Title XVII program discussed earlier (ADC 2018).

Big subsidies from the Chinese side are also likely. China has been active worldwide with state-led development deals to secure access to strategic minerals, including energy. Chinese state-owned enterprises routinely benefit from state support, including through preferential taxation and access to favorable credit terms.\(^4\) This project is unlikely to be

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\(^4\) A detailed review of China’s foreign aid strategy by Wolf, Wang, and Warner the (2013) found that “such programs have burgeoned in recent years, with emphasis on development of increased foreign supplies of energy resources, as well as supplies of ferrous and nonferrous minerals. Loans finance many of these programs and feature substantial subsidization, but are also accompanied by rigorous debt-servicing conditions that distinguish
different. CEIP itself is viewed as a strategic enterprise by Moody’s; it is likely the Chinese government shares this view, and will use the leverage of the State to support it.  

In March 2018, the State of Ohio announced an ethane cracker with an estimated cost of $10 billion was going to move forward in Belmont County with backing from Thailand’s PTT Global Chemical and South Korea’s Daelim Industrial Co. (Junkins 2018). As with the other portions of this deal, information on state subsidies, either foreign or US, remains sparse.

In mid-April, the US and other trading partners raised a concern at the World Trade Organisation about state subsidies leading to creation of overcapacity in key industries, and how that overbuilding harms market competitors. While the communication mentioned steel and aluminum, similar arguments apply to mega projects such as the Appalachian Storage Hub. The submittal noted that

...capacity is often created pursuant to industrial policies to develop national strategic industries or to maintain the companies in these industries if they begin to fail. The overarching point in these instances of creation and maintenance of capacity is that the relevance of market forces diminishes when the state – functioning as the leading economic actor – owns, controls, or influences large industrial enterprises and banking entities. Simply put, direct or indirect government ownership and control can result in political considerations dominating what should be exclusively commercial decisions. This is especially problematic when the state owns or controls both the lender and borrower in a financial transaction. (WTO 2018).

4. Simplifying Actionable Subsidies: PJM focuses on the revenue side, but reducing costs or return uncertainty affects market offers in the same way

PJM’s definition of actionable subsidies focuses on revenue impacts, but these are not the only way subsidies boost expected returns of a subsidized activity. Policies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions. PJM appears to focus only on revenues, stating that capacity repricing “is including only those subsidies that would have a material impact on the seller’s overall revenues from the subsidized resource” [emphasis added] (PJM 2018: 69).

Similarly, its de minimis test focuses on revenues as well. If PJM intends this to capture “net revenues” (though the proposed tariff language suggests it does not), that would

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China’s foreign aid from the grant financing that characterizes development aid provided by the United States and other nations of the Organization for Economic Co-operation and Development.”

5 In a note discussing the merger last year, the firm wrote “Moody’s also believes that the combined entity will continue to have a high strategic importance to China’s energy sector, due to its positions as the largest power generation company and coal producer in the country. The combined entity will also be the largest wind power generation company in China.” (Moody’s 2017).
incorporate reduced costs to some degree. However, there is some risk – as is common with royalty calculations that allow deductions for expenses such as transportation – of gaming by bidders. The overall magnitude of support, whether on the cost, revenue, or risk stabilization side, would be a more neutral metric. Further, definitions that leave only revenue impacts as the focal point suggest that PJM intends to focus primarily on purchase mandates, rather than other forms of government support as well.

5. Definitional and data problems will systematically exclude some types of support from review

Subsidies can be created by many different policy mechanisms. These vary widely in complexity. Direct spending and research and development (R&D) support involve visible line items in budgets, where both the amounts and the purpose are clear. Revenue losses to the government Treasury from tax expenditures are increasingly estimated as part of the standard budgeting process, even at the state level. Even with this positive trend, however, the estimates are less precise than direct spending, and are much more difficult to allocate to beneficiaries. Most tax expenditure data sets, including the ones used to support this paper, also have some gaps. Understanding where they are, which are material, and whether different states have the same gaps, can all be challenging. Assessing the competitiveness of natural resource lease auctions, or the value of liability transfers, is also quite difficult to do. As a result, these types of supports are often missing entirely from subsidy assessments.

A lack of information, unfortunately, is not correlated with a lack of subsidization. In fact, because receiving large subsidies can sometimes create reputational risks for both the politician and the recipient firm, there may be perverse incentives to shift larger value subsidies to less visible and more-difficult-to-value mechanisms.

To the extent that PJM is ignoring entire classes of subsidies, such as those arising from state tax policies, the risk of bias across fuel cycles rises substantially. This is true whether the exclusion results from a definitional oversight in what PJM wants to track; or from policies that PJM’s definitions seem to include, but for which data allowing valuation and attribution aren’t readily available.

5.1. Assessing category gaps in PJM subsidy definitions

Translating a general definition of actionable subsidies into a more detailed roadmap of what types of policies might be overlooked is an important step in gauging areas where the current proposal may need adjusting. Definitional gaps are assessed by comparing my generic overview of key subsidy mechanisms (Table 1, below, left column) to information from PJM. This includes the definition PJM incorporated into its FERC filing, and a breakout of subsidy types assembled by the Capacity Construct Public Policies Senior Task Force (CCPPSTF) over the
course of work prior to PJM’s filing. Potential gaps are noted in Table 1 as well. Despite the length of the table, the exercise is a useful way to identify potential gaps in a structured way.

Tracking subsidies via direct spending appears to be well addressed by PJM. Tax revenue foregone and credit support are both also covered in the PJM definitions and state action categories. However, significant holes likely remain regarding how well these classes of support are tracked in practice. Liability subsidies and subsidized provision of energy-related goods or services are not well captured in current PJM actionable subsidy formulations. With the exception of direct spending, all of these subsidy types result in reduced costs or capping or shifting of operating risks. They do not directly boost revenues, and so face potential exclusion in a narrow interpretation of PJM’s materiality test.

In contrast, PJM’s filing, including its definition of actionable subsidies and the examples it provides to illustrate policies of concern, capture purchase requirements (such as RPS) quite granularly.

The final category in Table 1 involves environmental externalities. Power resources differ widely in the environmental and health impacts they cause, though the PJM filing is largely silent on the topic. PJM mentions a preference for a separate system of pricing carbon, and notes that state preferences – including for carbon reduction – would be respected under their Capacity Repricing proposal (PJM 2018: 54, 55). However, given the degree to which actionable subsidies are primarily instruments trying to move the markets towards lower carbon, more focus on this issue would have been beneficial.

Addressing externalities such as pollution or health effects through market instruments is a well-recognized strategy in environmental economics. Taxing the pollutant is a first-best strategy; regulation or other approaches such as subsidies to pollution-reducing substitutes (e.g., an RPS) are less optimal. But broadly, subsidies to address externalities can improve market efficiency if they are done properly (policy design matters with these interventions, and there are more- and less-efficient ways to underwrite pollution reduction). It is a mistake to “treat externality payments like distortive, rent-seeking subsidies that simply provide financial aid to a group of producers without being directly tied to a quantifiable external benefit” (Bialke and Unel 2018: 11).
Table 1. Capture of Key Subsidy Mechanisms in PJM’s Actionable Subsidy Definition

<table>
<thead>
<tr>
<th>Mechanisms of Value Transfer to Energy Sector</th>
<th>How Characterized in PJM FERC Filing and State Action Listing</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Direct transfer of funds</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Direct spending</strong></td>
<td><em>Filing:</em> Material payments</td>
</tr>
<tr>
<td>Direct budgetary outlays for an energy-related purpose.</td>
<td><em>CCPPSTF:</em> 8. Grant Programs</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> Energy-relevant activities by the state, rather than through grants to a private party.</td>
</tr>
<tr>
<td><strong>Research and development</strong></td>
<td><em>Filing:</em> Material payments</td>
</tr>
<tr>
<td>Partial or full government funding for energy-related research and development.</td>
<td><em>CCPPSTF:</em> 8. Grant programs</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> None. R&amp;D affects costs of future resources; unlikely to be material to current bidding.</td>
</tr>
<tr>
<td><strong>Tax revenue forgone</strong>*</td>
<td><em>Filing:</em> Concessions or rebates</td>
</tr>
<tr>
<td>Special tax levies or exemptions for energy-related activities, including production or consumption; includes acceleration of tax deductions relative to standard treatment.</td>
<td><em>CCPPSTF:</em> 9. Tax incentives</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> Workgroup description focuses on tax exemptions and tax credits. There is another whole class of support through more rapid deductions (generating a time-value benefit) and organizational structures (such as Master Limited Partnerships) that are not being picked up.</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> At present the inventories are not capturing the pass-through of federal subsidies into the state tax code that often happens by default.</td>
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<tr>
<td></td>
<td><em>Potential Gaps:</em> Consistent data gaps regarding artificially low extraction tax rates relative to other jurisdictions, and county or municipal tax subsidies.</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> Aggregate revenue loss data does not always translate easily into tax subsidy estimates at the facility level.</td>
</tr>
<tr>
<td><strong>Other government revenue forgone</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Access</strong>*</td>
<td><em>Filing:</em> Potentially captured via inclusion of “concessions”.</td>
</tr>
<tr>
<td>Policies governing the terms of access to domestic onshore and offshore resources (e.g., leasing auctions, royalties, production sharing arrangements).</td>
<td><em>CCPPSTF:</em> Not captured.</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> Non-competitive lease tenders on public land; royalty reductions; state rules allowing royalty-free flaring, venting, or on-site use of extracted minerals on public or private leases.</td>
</tr>
<tr>
<td><strong>Information</strong></td>
<td><em>Filing:</em> Provision of free information could fall under “concessions”.</td>
</tr>
<tr>
<td>Provision of market-related information that would otherwise have to be purchased by private market participants.</td>
<td><em>CCPPSTF:</em> Not captured.</td>
</tr>
<tr>
<td></td>
<td><em>Potential Gaps:</em> Examples would include geological surveys for mineral location or seismic risks to energy infrastructure; or data and statistics collection of relevance to producers.</td>
</tr>
<tr>
<td>Mechanisms of Value Transfer to Energy Sector(^1)</td>
<td>How Characterized in PJM FERC Filing and State Action Listing?(^2)</td>
</tr>
<tr>
<td>---</td>
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<tr>
<td><strong>Transfer of risk to government</strong></td>
<td></td>
</tr>
<tr>
<td>Lending and credit&lt;br&gt;Below-market provision of loans or loan guarantees for energy-related activities.</td>
<td><em>Filing:</em> Potentially captured under concessions or subsidies categories.&lt;br&gt;<em>CCPPSTF:</em> 7. Loan programs.&lt;br&gt;<em>Potential Gaps:</em>&lt;br&gt;-PJM excludes broader credit programs not stated as for energy; in practice, powerful industries within a state will capture large portion of more general loan programs as well.&lt;br&gt;-Advanced Cost Recovery or CWIP schemes act as interest-free loans from customers to utilities, and would fit well within this category. These were included in CCPPSTF discussion documents, though ultimately excluded.</td>
</tr>
<tr>
<td><strong>Government ownership(^*)</strong>&lt;br&gt;Government ownership of all or a significant part of an energy enterprise or a supporting service organization. Often includes high risk or expensive portions of fuel cycle (oil security or stockpiling, ice breakers for Arctic fields).</td>
<td><em>Filing:</em> Definition broad enough to potentially incorporate many subsidies that arise with state ownership. However, cooperative and municipal utilities, which are tax-exempt and benefit from other subsidies as well, are excluded as a category.&lt;br&gt;<em>CCPPSTF:</em> 10. State takeover, though this is defined quite narrowly.&lt;br&gt;<em>Potential Gaps:</em>&lt;br&gt;-Subsidies to publicly-owned utilities.&lt;br&gt;-Federal takeovers of generators (e.g., under DPA) or ownership of key portions of the fuel cycle (e.g., nuclear waste).&lt;br&gt;-State responsibility for ensuring private market safety (e.g., mine inspections) or repairing public ways damaged by energy-related activities (e.g., highways) with insufficient fees from industry.</td>
</tr>
<tr>
<td><strong>Risk</strong>&lt;br&gt;Government-provided insurance or indemnification at below-market prices.</td>
<td><em>Filing:</em> Possibly includible as a concession. No risk examples included by PJM however.&lt;br&gt;<em>CCPPSTF:</em> Not captured.&lt;br&gt;<em>Potential Gaps:</em>&lt;br&gt;-Federal involvement to cap liability for nuclear accidents and oil spills. States may also have some liability for oil spill cleanup.&lt;br&gt;-Liability risks associated with hydro dam failures is poorly characterized, but likely affects all levels of government.&lt;br&gt;-Legacy liabilities for improperly insured private risks in the past often fall to government; reclamation of abandoned coal mine lands is an example.</td>
</tr>
<tr>
<td><strong>Induced transfers</strong></td>
<td></td>
</tr>
<tr>
<td>Cross-subsidy(^*)&lt;br&gt;Policies that reduce costs to particular types of customers or regions by increasing charges to other customers or regions.</td>
<td><em>Filing:</em> Not addressed. Focus on facility-level bid prices.&lt;br&gt;Subsidies via RECs and ZECs often borne entirely by retail customers.&lt;br&gt;<em>CCPPSTF:</em> 11. Rate-based cost recovery for certain resources.&lt;br&gt;<em>Potential Gaps:</em>&lt;br&gt;-Rate basing cross subsidies in CCPPSTF seemed limited to DSM and efficiency. High cost power resources such as advanced coal may also be rate-based, but would not seem to be included. In contrast, high cost offshore wind would be handled via a REC carve-out, so would be easily measurable and actionable by PJM.&lt;br&gt;-Rate class cross-subsidies probably not relevant to capacity auctions, which focus on unit-level costs.</td>
</tr>
<tr>
<td>Mechanisms of Value Transfer to Energy Sector¹</td>
<td>How Characterized in PJM FERC Filing and State Action Listing?²</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>-------------------------------------------------------------</td>
</tr>
<tr>
<td>-Power trading between ISOs may give rise to some relevant issues if an out-of-region generator is heavily subsidized.</td>
<td></td>
</tr>
</tbody>
</table>
| **Purchase requirements**<sup>*</sup>  
Required purchase of particular energy commodities, such as domestic coal, regardless of whether other choices are more economically attractive. | **Filing:** Captured as “other material support or payments obtained in any state-sponsored or state-mandated process.”  
Used as examples of actionable subsidies.  
Possible gaps: Any federally-implemented purchase mandates (e.g., for coal or nuclear) would be excluded from review. |
| **Regulation**<sup>*</sup>  
Government regulatory efforts that substantially alter the rights and responsibilities of various parties in energy markets or that exempt certain parties from those changes. Distortions can arise from weak regulations, weak enforcement of strong regulations, or over-regulation (i.e. the costs of compliance greatly exceed the social benefits). | **Filing:** Possibly captured as benefits from a “state-mandated process.”  
**CCPPSTF:** Not captured.  
Possible gaps:  
-Regulatory exemptions for particular industries can provide significant cost reductions, but do not seem captured.  
-Regulated returns may provide subsidies to selected infrastructure (e.g., affiliate pipelines), contributing to overbuilding certain segments of the fuel cycle. |
| **Costs of externalities**  
Costs of negative externalities associated with energy production or consumption that are not accounted for in prices. Examples include greenhouse gas emissions and pollutant and heat discharges to water systems. | **Filing:** Not addressed.  
**CCPPSTF:** 2. Emissions tax; 3. Cap-and-trade.  
**Potential Gaps:**  
-likely to be residual negative externalities not being well captured even after these carbon constraints are incorporated.  
-CCPPSTF shows cap and trade schemes in DE and MD as generating a negative value (i.e., they act as a tax on capacity). Application of capacity pricing or MOPR-Ex rules could possibly be interpreted to add back these fees, making the capacity more competitive in the auctions and obviating state efforts to address environmental externalities of the power source. |

**Sources:**  
¹Koplow (2017a) and Koplow (2017b).  
5.2. Review of state-level data on energy subsidies

After exclusions for federal support and state or local support targeted at regional redevelopment or plant location, PJM seems to be focusing primarily on purchase mandates as actionable subsidies (PJM 2018; Giacomoni 2018). Such a focus is narrower than the subsidies that had been identified by the CCPSTF (2017). In turn, the subsidies included by the CCPSTF seem not to have incorporated any of the additional interventions flagged in a subsidy “short-list” suggested to the workgroup by CCPSTF member Natural Resources Defense Council (Koplow 2017).

An updated review of available data on state level support indicates that there are many other types of subsidies currently in place. This review incorporated updated information from the Subsidy Tracker database, included in the Appendix as Table A.1. OECD updated its data on US state and federal subsidies to fossil fuels earlier this year as well, adding revenue loss and expenditure information that has become available since its last inventory in 2015. An extract of that data (OECD 2018a) for the PJM region can be found in Table A.2 (tax expenditures) and A.3 (direct outlays). Because OECD has been tracking subsidies for many years, the tables show subsidy values both for recent years and for the 2007-2018 period during which PJM capacity markets have been in place.

The vast majority of entries in the OECD inventory are tax expenditures. Direct expenditures are also captured, and sometimes large as well. However, the direct expenditures relating to fossil fuels in the PJM region are much smaller than the largest tax breaks. The direct spending focuses primarily on safety, inspection and worker training for the coal industry.

Systematic tracking and quantification of subsidies other than direct spending and tax expenditures has been a technical and administrative challenge. The Compendium to the OECD 2018 Subsidy Inventory (OECD 2018b) includes important information on the tracking and valuation of credit support. Credit subsidies are frequently provided by governments to private industry around the world, and the quantification approach discussed is a big step forward in trying to track the value of these supports. In future years, the subsidies associated with individual loan and loan guarantee programs will hopefully start to be tracked routinely. Detailed tracking of subsidies employing still more complex value transfer mechanisms such as natural resource leasing, state-owned enterprises, liability caps, and insurance remain many years off.

Most tax expenditures within the OECD inventory are self-reported by member governments or pulled from state tax expenditure budgets. These sources sometimes have gaps. Tax breaks at the local level such as property taxes may not be included and often don’t show up in state tax expenditure reports either. Pennsylvania’s exemption of gas reserves and related infrastructure from property taxes is an example. Another gap occurs when taxes on energy minerals are well below levels found in other jurisdictions. The state won’t necessarily flag this as a tax subsidy, though clearly the low rate accelerates resource development.
Overall, OECD provides the most comprehensive inventory of national and state subsidies to fossil fuels. However, because it captures only a slice of government support, the disparity between the inventory and the full level of subsidization can sometimes be large. For example, with a surging natural gas industry, Pennsylvania’s lack of severance or property taxes on natural gas is worth more to the industry than any of the PA tax expenditures listed in Table A.2.

This paper does not tally up OECD figures for a few reasons. First, their application to generation potentially bidding into PJM capacity markets will vary by resource. Second, individual provisions serve as useful illustrations for some of the challenges of accurately assessing impacts on capacity auctions. As shown in Table A.2, for example, Pennsylvania has a special sales tax exemption for coal that results in revenue losses of about $125 million per year, and about $1.5 billion over the 2007-2018 period. This does not apply to all fuels, so is clearly a targeted subsidy to the coal fuel cycle. A similar tax expenditure in Kentucky is valued at $34 million for 2018, and almost $700 million during the 2007-2018 period.

In contrast, a Pennsylvania tax exemption for utility sales to residential customers, generated much larger revenue losses, estimated at $458 million in 2018. However, this provision applies to all forms of electricity, natural gas, LPG and fuel oil rather than to a single fuel. The portion flowing to electricity would be of most relevance to PJM capacity auctions; but the point of incidence is consumers. The likely result is that consumers buy more electricity, which would clearly disadvantage demand reduction or efficiency options. But it is not clear that this type of subsidy would tip the scale in any one direction with respect to type of power generation. Extraction subsidies, discussed in the next section, are more likely to do that.

6. Distinctions by Energy Type

PJM’s definition of an actionable subsidy results in greater coverage of supports directed at some types of energy than others. As noted above, this partly results from definitional gaps in the types of policy instruments captured. Additional variability in coverage also results from direct exclusions for particular forms of energy. This section reviews which energy resources are either subject to different rules, or exempt entirely from them; and assesses how these exclusions could affect the neutrality of the proposal.

In addition, and particularly in light of surging production of natural gas and natural-gas fired electricity, the section also addresses the significance of subsidies to upstream or downstream stages of production for key electricity fuel cycles.

6.1. Energy resource neutrality

Power as a byproduct. The proposal excludes a number of resources from consideration for actionable subsidies including energy efficiency and facilities that produce electricity as a
byproduct, such as landfill gas, wood waste, municipal solid waste, black liquor from paper manufacturing, coal mine gas and distillate fuel oil (PJM 2018: 74). PJM argues that “because the economics of energy production and energy market participation for these resources is much more complicated than for a typical Generation Capacity Resource,” and capacity market revenues are not critical for continued operation, they “do not present the price suppression concerns that these market rules address” (PJM 2018: 74).

It is true that power production may be ancillary to the core business for some of these industries and sales may vary somewhat based on production demands. But these are mostly large scale process industries that run every day all day. Because they have other revenue streams, and need to process the wastes for their operations to run smoothly, they might have an incentive to bid low in capacity auctions in order to get at least some capacity revenue for their power operations. It is also the case that the energy conversion process at these facilities is subsidized, sometimes heavily so, both through the federal tax code and via many state renewable portfolio standards. Absent the subsidies, nearly all would continue operations, including power generation. Perhaps the prices in their core industry would rise slightly, though this could actually have environmental benefits. For example, lower prices at landfills and waste-to-energy plants due to subsidies to ancillary energy operations can erode the economics of source reduction and recycling (Koplow 2001), both of which have a better environmental footprint. Whatever the driver, underpricing of these resources in capacity auctions would seem to raise the same concerns with suppressed clearing prices as PJM worried about in other contexts.

Renewables under RPS. In its filing, PJM focuses heavily on renewable purchase mandates (via either RPS or REC systems). The programs currently exist in some form in 11 of the 14 PJM states (including the District of Columbia). Five of the 11 instituted programs prior to the inception of the first capacity market delivery in 2007-08, with the first two in the late 1990s. Three programs were instituted in 2007, and only three states after the capacity market in PJM was already functioning (Barbosa 2017; PJM Environmental Information Services 2017; NC Clean Energy Technology Center 2018). In the world of energy subsidies, these are late entrants.

Aside from large scale hydroelectric power projects owned by the federal government, federal subsidies to renewables were near zero in 1989 (Koplow 1993). This started to change only with the introduction of tax breaks, primarily production tax credits for qualified renewable resources, in the federal Energy Policy Act of 1992. In contrast, OECD data in Table A.2 show many large state tax breaks to fossil fuels being introduced in the 1950s, 1960s, and 1970s. Core federal tax breaks to conventional energy are even older. Expensing of intangible drilling costs for oil and gas began in 1913; percentage depletion for oil and gas started in 1926, and for coal in 1932. Liability limits on nuclear accidents took effect in 1957, and responsibility to store and monitor high level nuclear waste was effectively nationalized in 1982 (Koplow 2017).
Nonetheless, PJM analysis indicates the subsidies per MWh in the RPS programs can be large. As such, if resources procured pursuant to these policies were subject to the minimum offer price rule, many would likely fail to clear the capacity market auction. The MOPR-Ex proposal includes an exemption for resources supplying a state-sponsored renewable portfolio standard so long as that RPS program meets certain conditions. PJM’s approach under MOPR-Ex is to grandfather renewables for which at least an RFP was issued prior to December 31, 2018, regardless of the structure of the RPS procurement.⁶ Procurements under RPS or REC regimes after that date would continue to be exempt from the minimum offer price rule, despite generating non-market revenues, where they are acquired via a "competitive and non-discriminatory" process. Such a process must include at least three bidders, select winners based on the lowest price, set payments based on the auction clearing price, and treat existing capacity equally to new capacity, among other factors (PJM 2018: 113-114).

There is some question as to how important renewables covered by renewable portfolio standards are to capacity markets in general. A combination of low market share and heavily discounted capacity values result in a fairly small footprint as a capacity supplier. Total installed capacity as of December 31, 2017 was 35.4% coal, 36.8% gas, 18% nuclear, 3.6% oil and 4.8% hydro. Wind, waste-to-energy plants, and solar capacity were only 0.6%, 0.4%, and 0.2% respectively (Monitoring Analytics LLC 2018: 36).

6.2. Relevance of fuel cycle subsidies to electric power capacity markets

Subsidies to fuel extraction and transport; fuel processing (e.g., uranium enrichment or gas plants); reclamation of mine sites and management of wastes; and infrastructure decommissioning all play an important role in the economics of the associated form of electricity. Focusing only on subsidies targeted directly at power production or sale will skew policy oversight away from forms of electricity that have more, or more complicated, upstream and downstream steps. The result will likely be to undercount supports to nuclear, fossil, and hydroelectric power relative to “fuel free” resources such as wind and solar.

It is also likely that at least some of these subsidies are important enough to affect the minimum bid prices in PJM capacity auctions. Indeed, the CCPPSTF did incorporate some subsidies to input fuels in Key Work Assignment #2 of its State Policy Options workbook (CCPPSTF 2017). While this is an indication that some Task Force members viewed them as relevant, upstream subsidies are not addressed directly in the subsequent PJM filing with FERC. Further, the connection between extraction and power plants within particular regions is often a close one -- more than 80% of coal from West Virginia went into electric power production, and most of it within PJM (Figure 1).

---

⁶ Resources procured pursuant to a voluntary RPS are not grandfathered.
Figure 1. Destination States for WV Coal Shipments to Electric Utilities, 2011 vs 2016

Source: Figure is from Lego and Deskins (2017: 4).

Surging natural gas in Pennsylvania is another example of these important links. PJM capacity auctions in 2010 through 2017 added 50,792 MW of new generation capacity, more than three quarters of which was natural gas (PJM 2018: 10). Gas deliveries for Pennsylvania electric generation increased from 3% of total deliveries in 1997 to 46% in 2015, growing from 20 Bcf to 501 Bcf (Stewart 2017: 5). And despite electric power already being the largest end use sector for natural gas, the transition is not abating: nearly all new planned power capacity is natural gas (Stewart 2017:10). Despite growing in-state consumption, gas exports – including to other PJM states -- are even larger, comprising nearly 77% of total demand in 2015 (Stewart 2017: 18).

6.2.1. Upstream tax subsidies

Extraction of hard rock and fuel minerals has been subsidized through the tax code for more than a hundred years. Tax breaks at the federal, state, and local levels remain today. For most industries, investment costs are deducted over the service life of the investment. For oil and gas, many expenses can be deducted from taxable income immediately (intangible drilling costs, tertiary injectants) or more quickly than their service life (geological and geophysical expenses, gathering lines). Acceleration of tax deductions boosts the after-tax income of recipients on a present value basis. The percentage depletion allowance allows mineral firms to deduct investments based on the market value of the mineral rather than the actual investment spending. As a result, deductions can exceed the total amount invested. In many cases, federal tax breaks are mirrored in state statutes, increasing their total value to the firm.
Natural gas production in Pennsylvania is partly supported by sub-national tax breaks as well, particularly regarding severance and property taxes.

Revenue losses to the State or municipal governments can be very large when a state decides to impose no taxes, or much lower rates, on extraction activities relative to surrounding jurisdictions. This is the case in Pennsylvania, one of only two states in the country with no severance tax. Pennsylvania also fully exempts oil and gas (though not coal) reserves and related equipment from local property taxes, something most oil states don’t do.

This information, however, won’t be visible in most of the standard compilations of tax breaks. Property taxes are local, even though statutes on exemptions may have been determined at the state level. And OECD treats each taxing jurisdiction as setting its own baseline, so doesn’t impute “missing” taxes if levels are below average. But industry notices, and drilling activity rises.

Raimi and Newell evaluated the state and local tax structure for the 16 largest oil and gas producing states. Thirteen of these levied property taxes on oil and gas reserves. Pennsylvania does not. Severance taxes compensate states for the permanent extraction of a non-renewable resource. Of the 16 largest producing states, only Pennsylvania and California have no severance taxes. As shown in Table 3 (Raimi and Newell 2016: 5-7), PA and OH had the lowest tax take among the whole sample, at 2.33 and 1.11 percent, respectively in 2013. West Virginia was higher, at 7.79%, though the chart focuses only on oil and gas. WV historically has had a relatively small oil and gas industry and many subsidies to coal instead. The effective rates for 2013 actually represent an improvement: for the period 2004-13 state and local taxes on oil and gas averaged roughly half the 2013 level, at 1.2%, 0.3%, and 4.2% in PA, OH, and WV. Three other PJM states were also in the lowest tier for effective state and local taxation of oil and gas nationally: IL (0.1%), IN (0.9%), and VA (0.0%) (Weber, Wang and Chomas 2015: 27).

Applying the same effective tax rate as Texas in Pennsylvania would have generated roughly $400 million in additional revenue in 2013, even ignoring the continued full property tax exemption on billions of dollars in natural gas infrastructure. The revenue losses to county governments from the oil and gas exemptions to property taxes in Pennsylvania were estimated by a mineral appraiser at $477 million in 2012, rising to $660m in 2013 and nearly $1 billion in 2014 as the surge in investment continued (Kern 2011 in Simeone 2012: 12). Attempts to get updated figures from this analyst were not successful.

In lieu of a severance tax, PA introduced an “impact fee”. It is not really a substitute, however. Severance and property taxes should finance general government operations. To the extent that impact fees are used mostly to offset the impacts that gas drilling has on community budgets through road damage, congestion or higher public safety costs, it is not really contributing to ongoing general state operations as taxes on other sectors of the economy do. The fee should supplement severance and property taxes rather than replacing them. Even so, revenues from Pennsylvania’s impact fee have been falling despite rising production. Between 2014 and 2016, unconventional gas production jumped by 25%, an
increase of more than 1 billion cubic feet; yet impact fees dropped 22%, by near $50 million. Impact fees as a percent of sales is projects to be only 1.2% for 2018, down from 4.5% in 2011 (Polson and Herzenberg 2017: 3,4).

Table 2. Implicit tax breaks to oil and gas extraction in PA and OH appear large

<table>
<thead>
<tr>
<th>State</th>
<th>Severance tax</th>
<th>Other state taxes/fees</th>
<th>Local property taxes</th>
<th>State leases</th>
<th>State share of federal leases</th>
<th>Value of Production</th>
<th>State and local taxes/production value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$millions</td>
<td>$millions</td>
<td>$millions</td>
<td></td>
<td>$millions</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td>AK</td>
<td>3,972</td>
<td>107</td>
<td>429</td>
<td>2,80</td>
<td>19</td>
<td>18,900</td>
<td>23.85%</td>
</tr>
<tr>
<td>AR</td>
<td>91</td>
<td>—</td>
<td>42</td>
<td>No data</td>
<td>2</td>
<td>4,400</td>
<td>3.02%</td>
</tr>
<tr>
<td>CA</td>
<td>—</td>
<td>64</td>
<td>505</td>
<td>407</td>
<td>105</td>
<td>21,000</td>
<td>2.71%</td>
</tr>
<tr>
<td>CO</td>
<td>136</td>
<td>—</td>
<td>367</td>
<td>104</td>
<td>99</td>
<td>10,200</td>
<td>4.93%</td>
</tr>
<tr>
<td>KS</td>
<td>123</td>
<td>8</td>
<td>175</td>
<td>1</td>
<td>3</td>
<td>4,900</td>
<td>6.24%</td>
</tr>
<tr>
<td>LA</td>
<td>821</td>
<td>5</td>
<td>202</td>
<td>591</td>
<td>27</td>
<td>17,100</td>
<td>6.01%</td>
</tr>
<tr>
<td>MT</td>
<td>213</td>
<td>—</td>
<td>—</td>
<td>27</td>
<td>21</td>
<td>2,600</td>
<td>8.19%</td>
</tr>
<tr>
<td>ND</td>
<td>2,408</td>
<td>—</td>
<td>—</td>
<td>345</td>
<td>92</td>
<td>24,600</td>
<td>9.79%</td>
</tr>
<tr>
<td>NM</td>
<td>781</td>
<td>21</td>
<td>147</td>
<td>543</td>
<td>460</td>
<td>13,200</td>
<td>7.19%</td>
</tr>
<tr>
<td>OH</td>
<td>3</td>
<td>2</td>
<td>5</td>
<td>0</td>
<td>0</td>
<td>900</td>
<td>1.11%</td>
</tr>
<tr>
<td>OK</td>
<td>494</td>
<td>29</td>
<td>545</td>
<td>90</td>
<td>6</td>
<td>16,500</td>
<td>6.47%</td>
</tr>
<tr>
<td>PA</td>
<td>—</td>
<td>226</td>
<td>—</td>
<td>144</td>
<td>—</td>
<td>9,700</td>
<td>2.33%</td>
</tr>
<tr>
<td>TX</td>
<td>4,485</td>
<td>1</td>
<td>2,475</td>
<td>1,23</td>
<td>17</td>
<td>107,000</td>
<td>6.51%</td>
</tr>
<tr>
<td>UT</td>
<td>53</td>
<td>6</td>
<td>53</td>
<td>69</td>
<td>131</td>
<td>4,300</td>
<td>2.60%</td>
</tr>
<tr>
<td>WV</td>
<td>88</td>
<td>27</td>
<td>72</td>
<td>0</td>
<td>0</td>
<td>2,400</td>
<td>7.79%</td>
</tr>
<tr>
<td>WY</td>
<td>597</td>
<td>—</td>
<td>639</td>
<td>140</td>
<td>472</td>
<td>11,200</td>
<td>11.04%</td>
</tr>
<tr>
<td>Total</td>
<td>14,264</td>
<td>495</td>
<td>5,657</td>
<td>6,50</td>
<td>1,454</td>
<td>268,900</td>
<td>7.59%</td>
</tr>
<tr>
<td>Total, ex AK</td>
<td>10,293</td>
<td>389</td>
<td>5,227</td>
<td>3,700</td>
<td>1,436</td>
<td>250,000</td>
<td>6.36%</td>
</tr>
</tbody>
</table>

Source: Raimi and Newell (2016)

6.2.2. Tax-exempt corporate structures

Firms able to organize their activities in corporate forms that are eligible for lower corporate-level income taxes, or exempt from them entirely, garner a competitive advantage. The oil and gas sector has been particularly adept at doing this. An analysis by the Pennsylvania Budget and Policy Center estimated that as of February 2017, at least 65% of the oil and gas companies in PA were pass-through entities, paying no corporate-level taxation. These firms accounted for “68% of the gas produced in the state and 71% of active wells” (Polson and Hetzenberg 2017: 9). Standard corporations would have incurred a state corporate income tax of nearly 10%.

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7 Shareholders of both partnerships and standard C-corporations would also include the individual income taxes, at a rate of just over 3%. The effective rate on pass-throughs would be a bit higher, since paying no taxes on
For the much larger pipeline companies, the corporate structure of choice has been the Master Limited Partnerships (MLP). MLPs are one the very few corporate structures that are both exempt from corporate taxation and are also publicly traded. Issuing shares on the stock market allows these firms to reach the massive scale they need in order to build and operate pipelines, and also to raise capital more cheaply than would be possible otherwise. Not surprisingly, these attributes would be attractive to industries well beyond the oil and gas sector. In fact, during the early 1980s MLPs were expanding so fast across the US economy that Congress worried about huge drops in tax revenues. Their response was to disallow the structure in the Tax Revenue Act of 1987 (Koplow 2013). But their reforms had a few exemptions -- one of which was extractive minerals. Renewable energy firms are not eligible. As of August 2007, 82% of MLPs were in the natural resources segment, of which the vast majority were oil and gas. This subset of MLPs had a market capitalization of $300 billion (MLPA 2017).

MLPs are most active in the mid-stream area, often owning pipelines. Increasingly, private equity firms are also investing in these assets (Morris 2017). A handful of private equity firms are publicly traded as MLPs; many of the rest are privately held partnerships that also pay no corporate income taxes. MLPs are not just pipelines. The new Dominion Cove Point LNG facility is structured as a tax-exempt MLP as well. Its ability to eliminate corporate income taxes is bundled on top of the large property tax abatements it received from Calvert County to reduce the breakeven cost of the plant.

Between 2007 and 2016, FERC has approved pipeline projects involving PA that encompass 12,939 MM cf/day of capacity. An additional 7,292 MM cf/day of capacity was approved in 2017 alone (Simeone 2017). Most of these lines appear to be using tax exempt corporate structures. The dollars are big. Six major pipeline projects within the PJM service area have cost estimates totalling $16.6 billion (McKenna 2017).

6.2.3. Bulk fuel transport

Because coal and natural gas power plants burn so much fuel, subsidies to transport links can artificially reduce plant costs of operation. A combination of very heavy trucks, secondary roads with thinner road beds, and many trips to construct and service fracking operations and coal mine sites, can result in very rapid road wear. While most states have some supplemental fees paid by heavy trucks, these tend to be much lower than the actual damage.

The most detailed work on this issue has been done by the state of Texas. They found road damages exceeded user fees by roughly $2 billion per year. In assessing how various federal and state subsidies to oil affected the ability of oil fields to hit their minimum investment hurdles, the road subsidy to fracking operations in Texas turned out to have the corporate level means that slightly more earnings would pass out to shareholders to then be taxed at the individual level.

earth track
www.earthtrack.net
largest impact of any state-level support. The subsidy lifted the internal rate of return for projects in the Permian Basin by nearly 2 percentage points, a significant portion of the project hurdle rates (Erickson, Downs, Lazarus and Koplow 2017).

Damage from coal hauling is also problematic. A 1981 Kentucky legislative report found widespread road damage from coal hauling. Estimated costs to repair the damage were prohibitive. A major cause of the problem: “too many heavy and improperly loaded trucks have been traveling the state's highways. Laws enacted to protect the roads have been ignored” (VanArsdall 1981). The problem has persisted. A detailed assessment of the impact of the coal industry on the Kentucky state budget conducted by the Mountain Association for Community Economic Development (MACED) found annual road damage costs of more than $230 million per year in 2006 (Konty and Fry 2009). The scale of this subsidy was an important driver of MACED’s calculation that, on net, the coal industry cost the state more money than it brought in. Yet coal trucks continue to be allowed to exceed the weight limits by 10 percent on Kentucky’s secondary roads, though a 10 percent increase in weight limits can increase the damages to bridges by a third. (Cheves 2017 and Kentucky House Bill 174).

As noted already, pipeline systems benefit from an array of subsidies including accelerated depreciation, property tax exemptions, and tax-exempt MLP corporate structures. They have also had a fairly strong capability to obtain land needed for their lines using the power of eminent domain, a contentious and often litigated aspect of many of the lines going in to move gas from the Marcellus. Historically, coal has also moved in significant quantities on the inland waterway system, where coal and petroleum have long comprised more than half of the domestic tonnage. Fees on users have been insufficient to finance the inland waterway system, with more than 90 percent of funding coming from taxpayer subsidy rather than user fees, according to analysis by the Nicollet Island Coalition (2011). This is significantly higher than the public subsidy share to roads or rail.

6.2.4 Post-closure cleanup

Extraction sites, fuel processing, power plants, and pipelines all require remediation, reclamation or decommissioning after the minerals have been removed or the productive life of a facility ends. These costs often come at a time when company revenue drops sharply and management may be interested in moving on to other things. To prevent liabilities from continually being dumped on taxpayers, lawmakers have adopted a variety of approaches to better protect against financial shortfalls. These include reclamation bonding, mandated contributions into post-closure trust funds, or user fees on current market participants to help pay cleanup costs from firms no longer in business. While better than nothing, these approaches continue to face challenges (see, for example, Davis 2012 and Boomhower 2016).

One measure of the scale of these problems is the backlog on cleaning up old coal mining sites. Despite some continuing funding of this backlog from an excise tax on coal, the fee levels are too small and the pace of clean up too slow, to work through the backlog in a reasonable time frame. Table 4 provides some additional perspective on this. Within PJM,
many states have funded less than half of the reclamation cost to date. Unfunded reclamation liabilities total more than $11 billion within PJM, and the region accounts for more than three-quarters of the reclamation backlog nationally. Allowing bonding and reclamation accruals to be too low artificially reduces the operating costs for those mines. Further, if site owners expect they won’t actually be held to account for the messes they leave behind, they also have far less incentive to make more prudent decisions during operations.

Table 3. PJM dominates unfunded coal mine land reclamation nationally

<table>
<thead>
<tr>
<th>State</th>
<th>Unfunded Cost</th>
<th>Funded Cost</th>
<th>Completed Cost</th>
<th>Total Cost</th>
<th>Unfunded as % of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania</td>
<td>5,044,014,727</td>
<td>217,966,725</td>
<td>644,151,172</td>
<td>5,906,132,623</td>
<td>85.4%</td>
</tr>
<tr>
<td>West Virginia</td>
<td>1,563,561,572</td>
<td>72,272,703</td>
<td>676,163,130</td>
<td>2,311,997,405</td>
<td>67.6%</td>
</tr>
<tr>
<td>Kentucky</td>
<td>474,998,682</td>
<td>93,356,966</td>
<td>574,968,101</td>
<td>1,143,323,749</td>
<td>41.5%</td>
</tr>
<tr>
<td>Virginia</td>
<td>421,442,333</td>
<td>10,793,610</td>
<td>138,930,246</td>
<td>571,166,189</td>
<td>73.8%</td>
</tr>
<tr>
<td>Ohio</td>
<td>359,051,851</td>
<td>4,123,774</td>
<td>171,939,330</td>
<td>535,114,954</td>
<td>67.1%</td>
</tr>
<tr>
<td>Illinois</td>
<td>156,707,030</td>
<td>28,134,366</td>
<td>197,692,405</td>
<td>382,533,801</td>
<td>41.0%</td>
</tr>
<tr>
<td>Indiana</td>
<td>187,453,029</td>
<td>9,256,929</td>
<td>160,824,519</td>
<td>357,534,477</td>
<td>52.4%</td>
</tr>
<tr>
<td>Maryland</td>
<td>64,897,199</td>
<td>2,625,198</td>
<td>42,517,583</td>
<td>110,039,979</td>
<td>59.0%</td>
</tr>
<tr>
<td>Tennessee</td>
<td>44,666,578</td>
<td>1,550,510</td>
<td>47,368,888</td>
<td>93,585,976</td>
<td>47.7%</td>
</tr>
<tr>
<td>Michigan</td>
<td>3,360,000</td>
<td>1,610,000</td>
<td>5,959,034</td>
<td>10,929,034</td>
<td>30.7%</td>
</tr>
<tr>
<td>North Carolina</td>
<td>0</td>
<td>0</td>
<td>163,252</td>
<td>163,252</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>PJM summary</strong></td>
<td><strong>8,320,153,001</strong></td>
<td><strong>441,690,780</strong></td>
<td><strong>2,660,677,659</strong></td>
<td><strong>11,422,521,440</strong></td>
<td><strong>72.8%</strong></td>
</tr>
<tr>
<td><strong>PJM share of national total</strong></td>
<td><strong>79.3%</strong></td>
<td><strong>78.2%</strong></td>
<td><strong>66.8%</strong></td>
<td><strong>76.0%</strong></td>
<td></td>
</tr>
</tbody>
</table>

Notes: Includes only SMCRA funding, so data should include only coal mining operations. Other funding mechanisms in e-AMLIS include both coal and non-coal sites. Not all AML costs are included, only those potentially addressable under SMCRA. Won’t necessarily tie to state estimates.


7. Case Study: Exemption of Coal from Sales and Use Tax in PA

As the PJM filing is so focused on purchase mandates, it is useful to test a different type of policy to see whether it might also be deemed actionable under PJM’s proposed tests. Quantifying other types of subsidies requires several more steps, but is possible with the right data inputs. Whereas the value of support under an RPS or REC approach is a known amount per unit energy produced, valuing other types of support often requires a baseline against which to compare. In addition, most other forms of subsidy don’t flow directly to generator revenues. Rather, they affect net revenues by reducing cost or risk, or support other parts of the fuel cycle. While time permitted only one test case, running additional screens on a variety of subsidy types in the future would be useful.

Table 4 estimates the impact of Pennsylvania’s exemption of coal from sales and use taxes on the economics of coal-fired power plants. The subsidy value is in the form of “revenue loss,” which measures how much additional revenues the taxing authority would have realized.
if not for the special tax breaks. This is a loss to the Treasury, but a gain to the industry that gets to pay lower taxes. The baseline for tax breaks is how much a “normal” taxpayer would have had to pay on a comparable activity. For credit support, it would be what interest rate and loan terms a borrower of the same risk level would have received in the marketplace absent a government guarantee program.

Frequently, subsidy data is available only at an aggregated level. This is nearly always the case with tax breaks since tax returns are kept confidential. Aggregated values need to be allocated to specific beneficiaries based on the details of a particular tax break. Section III of Table 4 shows two adjustments made to the coal tax break: the first is to exclude subsidies flowing to coal that is exported out of state for use. The second is to exclude the portion of the subsidy flowing to coal consumers inside PA, but outside of the power sector. In both of these allocations, the estimates are likely conservative. Nearly three-quarters of coal exports in 2011 went to other PJM states (Pennsylvania Economy League of Greater Pittsburgh 2014), and a portion of industrial users of coal that were excluded from the calculation in Table 4 also generate power and may partake in PJM capacity markets.

After adjustments, the subsidy per MWh ranged from $0.83 to $1.57 per MWh.

The next step is to assess whether that level of support would be actionable under PJM’s proposed rules. Wholesale market revenues for all Pennsylvania coal plants were estimated for the years 2014-2017 on a MWh basis because plant or unit-level revenue data are not publicly available. Energy market revenues were determined based on the average annual day-ahead locational marginal price at the Western Hub, where all but one Pennsylvania coal plant sells power. As with any average, individual coal plants may have higher or lower average energy revenues per MWh than the group, depending on whether they tend to dispatch at peak or off-peak times. This energy market revenue estimate also excludes any uplift payments these generators might have received.

Capacity revenues were determined based on the RTO-wide clearing price in the base residual auction for delivery years 2013/14 through 2017/18. Capacity revenues were converted to per MWh basis for the purpose of this revenue analysis using the average capacity factor for Pennsylvania coal units that had operated in the previous year. This analysis conservatively assumes that all coal units cleared the base residual auction in these years; if any of these units did not clear, their wholesale market revenues would have been lower and therefore the value of the subsidy received as a percentage of revenue would be higher.

As shown in Section IV of Table 4, the tax savings from the subsidy were equivalent to more than 1 percent of revenues in all three years evaluated, reaching a high of 4.4% for 2016. Section V of Table 4 evaluates whether the affected MW of capacity would exceed the 5,000 MW threshold of actionable units system-wide in order for the subsidy adjustments to be acted on by PJM. Assuming all of the active units are clearing the capacity market, the 5,000 MW action threshold would be exceeded by a factor of more than two. This means about half of the PA units could not have cleared capacity markets and the threshold for action would still be
met. Further, the MW test applies PJM-wide. Thus, actionable coal units in PA even well short of 5,000 MW could nonetheless combine with actionable subsidies to other fuels and locations to tip the region over the action threshold.

Under PJM’s proposal as currently formulated, this tax break might be ignored because it doesn’t flow directly to revenues. It might be ignored because the point of impact is on input fuels, rather than directly to the power plant; or because it is more difficult to measure by PJM oversight staff than a simple RPS payment. But it is clear that the subsidy is material, likely part of a fairly big group of material subsidies outside of purchase mandates. Yet, if material subsidies are ignored because they are hard to measure, come in an excluded form from an excluded political jurisdiction, or reduce risks and costs rather than boosting revenues, the PJM system predicated to make wholesale capacity markets better could end up making them worse.

Table 4. Revenue test: Sales tax exemption for Pennsylvania Coal

<table>
<thead>
<tr>
<th>I. Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sales Tax Exemption for Coal.</strong> The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state’s coal-mining industry (OECD 2018a).</td>
</tr>
<tr>
<td>The tax exemption is provided to coal as an input, not at the point of power generation. This calculation adjusts subsidy amounts to remove the portion flowing to coal that is shipped to other states for consumption, or is used within Pennsylvania at industrial facilities not producing power.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>II. Magnitude of tax expenditure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2014</strong></td>
</tr>
<tr>
<td>Sales tax exemption, bituminous coal in Pennsylvania</td>
</tr>
<tr>
<td>Sales tax exemption, anthracite coal in Pennsylvania</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>III. Adjust subsidy value for reflect portion flowing to power sector inside PA</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Coal exports</strong></td>
</tr>
<tr>
<td>Export as share of total</td>
</tr>
<tr>
<td>Implied subsidy &quot;export&quot; to other states</td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal within PA</td>
</tr>
<tr>
<td><strong>B. Power sector share of total in-state coal consumption</strong></td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal by PA power producers</td>
</tr>
</tbody>
</table>
### Table 4, continued

<table>
<thead>
<tr>
<th>IV. One percent of revenues test</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Subsidy magnitude/MWh</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal by PA power producers</td>
<td>65,681,012</td>
<td>83,474,744</td>
<td>85,665,686</td>
</tr>
<tr>
<td>Coal fired generation in PA, MWh</td>
<td>78,985,629</td>
<td>64,637,233</td>
<td>54,672,030</td>
</tr>
<tr>
<td>Subsidy, $/MWh of coal-fired power produced in PA</td>
<td>0.83</td>
<td>1.29</td>
<td>1.57</td>
</tr>
<tr>
<td>From section III, above</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power output from PA utilities, independent power producers and combined heat and power. (EIA, State Electricity Profiles for PA, Tab 5).</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assumes subsidies to coal flow to coal users.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>B. Capacity and energy revenues for PA coal-fired generators</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Revenue per MWh</td>
<td>5.00</td>
<td>8.05</td>
<td>6.78</td>
</tr>
<tr>
<td>Energy revenue estimates determined by Sierra Club analyst Joe Daniel based on RTO-wide Base Residual Auction results for delivery years 2013/14 through 2017/18 (PJM data). Conversion of capacity to MWh basis based on average capacity factor for all Pennsylvania coal units in each calendar year, as determined from EIA net generation and capacity data reported in S&amp;P Global Market Intelligence. Small generators that had not reported generation data in a year were not included in the calculation of capacity factor.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Revenue per MWh</td>
<td>51.01</td>
<td>35.82</td>
<td>29.22</td>
</tr>
<tr>
<td>Total Revenue per MWh, PA average</td>
<td>56.01</td>
<td>43.87</td>
<td>36.00</td>
</tr>
<tr>
<td><strong>C. Subsidy exceeds the 1% revenue threshold for all three years</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subsidy/average wholesale revenues</td>
<td>1.5%</td>
<td>2.9%</td>
<td>4.4%</td>
</tr>
<tr>
<td>Tax breaks do not increase revenue because they are on the cost side. However, net revenues will rise.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>V. Affected units exceed the 5,000 MW PJM-wide threshold for action</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PA coal clearing capacity auctions that benefit from this subsidy</td>
<td>11,433</td>
<td>10,755</td>
<td>11,478</td>
</tr>
<tr>
<td>Sierra Club analyst Joe Daniel analysis of data reported in S&amp;P Global Market Intelligence.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>System-wide threshold for proposed capacity repricing rules to be implemented, MW</td>
<td>5,000</td>
<td>5,000</td>
<td>5,000</td>
</tr>
<tr>
<td>PJM (2018: 52)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ratio of potentially affected coal units/capacity repricing threshold</td>
<td>2.29</td>
<td>2.15</td>
<td>2.30</td>
</tr>
</tbody>
</table>
8. Conclusions

In its proposed tariffs to remove potential distortions caused by subsidies in capacity markets, PJM includes a number of limitations and exclusions that appear to result in unequal evaluation of subsidies across different fuel cycles. This will likely impede PJM’s core objective of ensuring competitive, nondiscriminatory auctions in the wholesale capacity market. Because subsidies flow to all forms of generation, and nearly every upstream and downstream stage of each power-related fuel cycle as well, a comprehensive review process is needed if PJM is to address these subsidies in a neutral way.

- **Blanket exclusion of federal and many state and local subsidies will reduce the accuracy of subsidy screening significantly.** PJM excludes all federal subsidies, and any state or local support that is in place for regional economic development or to convince a plant to locate (or stay) in a particular region. Federal subsidies can be both large and highly targeted to an industrial facility. State and local subsidies excluded on the basis of their stated purpose can also be very large. They may represent multiple state programs, originating from more than one agency — some of which may be excluded and others not based on the PJM proposal. In all of these areas, it is the scale of support rather than the justification for granting it that will drive capacity market distortions.

- **Revenue-based metrics for actionable subsidies need to be broadened to incorporate cost- and risk-reducing subsidies.** Subsidies operate using three main levers: boosting revenues, reducing costs, and reducing the volatility of expected return by absorbing or capping credit, liability, or other operating risks. The PJM proposal, as currently worded, focuses only on revenues and as a result will not treat different power sources equally. If a policy of mitigating subsidies is to be pursued, then the materiality test should shift from 1% of revenues to “a subsidy equal in magnitude to one percent of revenues” to incorporate the broad array of subsidy mechanisms.

- **Purchase mandates are one technique of many that governments use to transfer value to the energy sector; subsidy screening needs to incorporate all of them.** Not every form of electrical power has the same cost structure. Some are capital-intensive, rolling out new technologies, or face long or uncertain build times. Others require complex fuel supply chains, have risks of severe accidents, or significant and complex post-closure concerns. Still others have variability in their ability to produce electricity. As a result of these differences, the importance of particular types of subsidy support varies significantly across fuels, and rules that by definition or effect limit review to a small subset of subsidy approaches will materially disadvantage some energy resources over others.

- **PJM’s current focus almost entirely on purchase mandates will understate the level of subsidies to other forms of energy.** In addition, where interventions are focused on internalizing environmental or health externalities that are not being addressed in other ways, PJM needs to evaluate the impact on efficiency using more than just generator costs of operation.
• **Large subsidies to upstream or downstream fuel cycle steps need to be addressed to determine when a subsidy should be actionable.** These types of supports are most relevant regarding subsidies to coal and natural gas extraction and transport; coal mine land reclamation; large state support to ancillary infrastructure to move or process fuels; or state subsidy for high risk, long-term parts of the nuclear fuel cycle.

• **Subsidy combinations matter.** If there are multiple subsidies flowing to the same beneficiaries that in total exceed PJM’s action threshold of support equal to 1% of revenues, these should be reviewed as a group for action even if individually they don’t hit 1%. Subsidy “stacking” is common across the world, and it is the joint effect of multiple subsidies that will drive the distortions in market behavior.

• **Test case illustrates the importance of a more systematic inclusion of subsidies as potentially subject to PJM action.** A test case relating to tax exemptions for coal in the state of Pennsylvania indicates that more subsidies than just purchase mandates would exceed the PJM’s proposed revenue threshold. Additional analysis would likely illustrate a similar situation in multiple other parts of PJM, though this one example is useful in illustrating why a narrow focus on purchase mandates will be insufficient in addressing potential distortions.
9. Appendix – Subsidy Tables

Table A.1. Subsidies to specific energy facilities within PJM Interconnection (showing >$20 million only)

<table>
<thead>
<tr>
<th>Company</th>
<th>Location</th>
<th>Project Description</th>
<th>Year of Decision</th>
<th>Subsidy Value (multiple years)</th>
<th>Program Name</th>
<th>Awarding Agency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royal Dutch Shell</td>
<td>Pennsylvania</td>
<td>ethane cracker plant</td>
<td>2012</td>
<td>$1,650,000,000</td>
<td>special state tax credits</td>
<td>state legislature</td>
</tr>
<tr>
<td>Clean Coal Power Operations (KY) LLC</td>
<td>Kentucky</td>
<td>coal to diesel plant (inactive)</td>
<td>2008</td>
<td>$550,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Dominion Cove Point LLC</td>
<td>Maryland</td>
<td>expansion of a facility for the liquefaction of natural gas</td>
<td>2013</td>
<td>$506,000,000</td>
<td>Payment in Lieu of Tax</td>
<td>Calvert County Board of County Commissioners</td>
</tr>
<tr>
<td>Hemlock Semiconductor (controlled by Dow Corning)</td>
<td>Michigan</td>
<td>solar cell and semiconductor manufacturing</td>
<td>2008</td>
<td>$372,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Holtec International</td>
<td>New Jersey</td>
<td>small nuclear reactors manufacturing facility</td>
<td>2014</td>
<td>$260,000,000</td>
<td>Grow New Jersey Assistance Program</td>
<td>Economic Development Agency</td>
</tr>
<tr>
<td>Kentucky Syngas, LLC</td>
<td>Kentucky</td>
<td>Coal to gas plant</td>
<td>2007</td>
<td>$250,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Dow Kokam (previously known as KD Advanced Battery Group)</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2009</td>
<td>$194,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Marathon Petroleum</td>
<td>Michigan</td>
<td>refinery expansion</td>
<td>2007</td>
<td>$186,000,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Cash Creek Generation</td>
<td>Kentucky</td>
<td>coal gasification plant</td>
<td>2008</td>
<td>$150,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Company</td>
<td>Location</td>
<td>Project Description</td>
<td>Year of Decision</td>
<td>Subsidy Value (multiple years)</td>
<td>Program Name</td>
<td>Awarding Agency</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>--------------</td>
<td>-------------------------------------------------------------------------------------</td>
<td>------------------</td>
<td>--------------------------------</td>
<td>---------------------------------------------------</td>
<td>-------------------------------------------------------------</td>
</tr>
<tr>
<td>Dow Chemical</td>
<td>Michigan</td>
<td>manufacturing facilities for renewable energy materials</td>
<td>2010</td>
<td>$129,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>fortu PowerCell, Inc.</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$112,600,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$100,000,000</td>
<td>Michigan Business Tax Battery Credit</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>United Solar Ovonic (no longer operating)</td>
<td>Michigan</td>
<td>solar panel production facility</td>
<td>2008</td>
<td>$96,900,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Secure Energy Kentucky</td>
<td>Kentucky</td>
<td>coal-to-liquid gasification plant</td>
<td>2011</td>
<td>$85,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Coal Synthetics (inactive)</td>
<td>Kentucky</td>
<td>coal-to-gas plant</td>
<td>2008</td>
<td>$80,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Marathon Petroleum</td>
<td>Ohio</td>
<td>oil company headquarters</td>
<td>2011</td>
<td>$78,500,000</td>
<td>multiple</td>
<td>Department of Development</td>
</tr>
<tr>
<td>Marathon Petroleum Corporation</td>
<td>Ohio</td>
<td>oil company headquarters</td>
<td>2011</td>
<td>$72,128,036</td>
<td>Job Retention Tax Credit</td>
<td>Department of Development</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>Hybrid and electric car batteries</td>
<td>2010</td>
<td>$42,000,000</td>
<td>Michigan Business Tax Battery Credit</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>Company</td>
<td>Location</td>
<td>Project Description</td>
<td>Year of Decision</td>
<td>Subsidy Value (multiple years)</td>
<td>Program Name</td>
<td>Awarding Agency</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>---------------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>------------------</td>
<td>--------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>------------------------------------------------------</td>
</tr>
<tr>
<td>NRG Energy Inc.</td>
<td>New Jersey</td>
<td>facility expansion</td>
<td>2013</td>
<td>$37,520,000</td>
<td>Grow New Jersey Assistance Program</td>
<td>Economic Development Authority</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$29,007,000</td>
<td>MEGA (Michigan Economic Growth Authority) Tax Credits</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>Plains and Eastern Clean Line LLC</td>
<td>Tennessee</td>
<td>purchase renewable wind energy, construct direct current electric transmission line that terminates at a new converter station and then ties into the Tennessee Valley Authority network</td>
<td>2014</td>
<td>$23,369,368</td>
<td>Shelby County PILOT Agreements</td>
<td>Economic Development Growth Engine</td>
</tr>
</tbody>
</table>

Source: Good Jobs First Subsidy Tracker Database, extract 27 April 2018.
Table A.2. Estimated Revenue Loses to State Treasuries in PJM Region from State-level Tax Expenditures Provided to Fossil Fuels

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales Tax Exemption for Residential Utilities.</td>
<td>NR</td>
<td>END</td>
<td>ELECTR</td>
<td>PA</td>
<td>416,000,000</td>
<td>423,300,000</td>
<td>440,300,000</td>
<td>458,400,000</td>
<td>4,987,500,000</td>
</tr>
<tr>
<td>Sales Tax Exemption for Coal.</td>
<td>NR</td>
<td>END</td>
<td>BITCOAL</td>
<td>PA</td>
<td>116,275,801</td>
<td>117,813,333</td>
<td>119,254,768</td>
<td>122,233,735</td>
<td>1,473,079,772</td>
</tr>
</tbody>
</table>

* Fuel Category:
- ELECTR: Electricity
- BITCOAL: Coal
- NATGAS: Natural Gas

Exemption includes sales of electricity, natural gas, LPG, and fuel oil to residential users in Pennsylvania from the sales and use tax normally levied on sales of most goods and services in that state. It is meant to ensure that households retain access to basic services or commodities. Allocated to fuels based on state consumption data.

The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state’s coal-mining industry.

All energy and energy-producing fuels used in manufacturing, processing, mining, or refining and any related distribution, transmission, and transportation services, to the extent that the cost of the energy or energy-producing fuels used exceeds 3% of the costs of production, are exempt from Kentucky’s sales and use tax.
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</thead>
<tbody>
<tr>
<td>Coal Used in the Manufacture of Electricity.</td>
<td>1960</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>KY</td>
<td>55,000,000</td>
<td>33,800,000</td>
<td>35,900,000</td>
<td>34,100,000</td>
<td>667,402,000</td>
</tr>
<tr>
<td>Coal Used in the Manufacture of Electricity.</td>
<td>1960</td>
<td>INDUS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>7,779,806</td>
<td>7,734,662</td>
<td>7,975,430</td>
<td>8,246,294</td>
<td>89,460,708</td>
</tr>
<tr>
<td>Coal Refuse Energy and Reclamation Tax Credit.</td>
<td>2016</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>7,207,178</td>
<td>9,609,570</td>
<td>9,609,570</td>
<td>26,426,318</td>
</tr>
<tr>
<td>Sales Tax Exemption for Energy and Energy Producing Fuels.</td>
<td>1960</td>
<td>INDUS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>7,779,806</td>
<td>7,734,662</td>
<td>7,975,430</td>
<td>8,246,294</td>
<td>89,460,708</td>
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<tr>
<td><strong>Sales Tax Exemption for Energy and Energy Producing Fuels.</strong> All energy and energy-producing fuels used in manufacturing, processing, mining, or refining and any related distribution, transmission, and transportation services, to the extent that the cost of the energy or energy-producing fuels used exceeds 3% of the costs of production, are exempt from Kentucky's sales and use tax.</td>
<td>1960</td>
<td>INDUS</td>
<td>LPG</td>
<td>KY</td>
<td>6,706,984</td>
<td>6,668,065</td>
<td>6,875,632</td>
<td>7,109,144</td>
<td>66,290,137</td>
</tr>
<tr>
<td><strong>Sales Tax Exemption for Coal.</strong> The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state's coal-mining industry.</td>
<td>NR</td>
<td>END</td>
<td>ANTCOAL</td>
<td>PA</td>
<td>4,724,199</td>
<td>4,786,667</td>
<td>4,845,232</td>
<td>4,966,265</td>
<td>51,620,228</td>
</tr>
<tr>
<td><strong>Excess of Percentage over Cost Depletion.</strong> Extends the corresponding federal provision for percentage depletion to Kentucky's own corporation tax system. Allows companies to calculate deductions from their taxable income based on a percentage of the gross income derived from mining or drilling for natural resources. Under normal income-tax treatment, producers would recover investment costs over time as resources are depleted. In the case of percentage depletion, the sum of</td>
<td>1954</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>3,058,703</td>
<td>2,893,368</td>
<td>2,893,368</td>
<td>2,893,368</td>
<td>31,285,793</td>
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<tr>
<td>deductions can exceed the actual cost of investment.</td>
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</tr>
<tr>
<td>Coal Incentive Tax Credit. Can be claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
<td>2000</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>KY</td>
<td>3,389,374</td>
<td>2,893,368</td>
<td>2,810,700</td>
<td>2,728,033</td>
<td>21,781,575</td>
</tr>
<tr>
<td>Railroad Improvement Tax Credit. Tax credit to certain railroad companies against the costs incurred for maintenance and improvement, and for railroad expansion or upgrades to accommodate the transport of fossil energy or biomass resources.</td>
<td>2009</td>
<td>TRANS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>2,700,000</td>
<td>2,600,000</td>
<td>2,500,000</td>
<td>11,100,000</td>
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</tr>
<tr>
<td>Thin Seam Tax Credit. Allows mining</td>
<td>2000</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>1,901,356</td>
<td>1,818,688</td>
<td>1,901,356</td>
<td>1,901,356</td>
<td>18,497,073</td>
</tr>
<tr>
<td>companies operating in the state to get a tax credit for coal mined from thin seams or from areas with a high overburden ratio. The credit is on a sliding scale from 2.25% to 3.75% of the value of the severed coal and based on the thickness of the seam, the ratio of overburden removed to coal severed, and the sulphur content of the coal.</td>
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</tr>
<tr>
<td>Coal Incentive Tax Credit. Can be</td>
<td>2000</td>
<td>GENER</td>
<td>COKCOAL</td>
<td>KY</td>
<td>686,901</td>
<td>586,379</td>
<td>569,625</td>
<td>552,871</td>
<td>4,677,064</td>
</tr>
<tr>
<td>claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
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</tr>
<tr>
<td>Coal Refuse Energy and Reclamation Tax Credit.</td>
<td>2016</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>PA</td>
<td>-</td>
<td>292,822</td>
<td>390,430</td>
<td>390,430</td>
<td>1,073,682</td>
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</tr>
<tr>
<td>Excess of Percentage over Cost Depletion.</td>
<td>1954</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>21,411</td>
<td>20,253</td>
<td>20,253</td>
<td>20,253</td>
<td>358,291</td>
</tr>
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</tr>
</tbody>
</table>

*Coal Refuse Energy and Reclamation Tax Credit. Credits may be awarded at a rate of $4 per 2,000 pounds of qualified coal refuse, capped at 22.2 percent of the available budget allocation per fiscal year. Credit may be used against personal income tax, corporate net income tax, capital stock and franchise tax, bank shares tax, title insurance company shares tax, insurance premiums tax, and mutual thrift institutions tax liabilities.

*Excess of Percentage over Cost Depletion. Extends the corresponding federal provision for percentage depletion to Kentucky’s own corporation tax system. Allows companies to calculate deductions from their taxable income based on a percentage of the gross income derived from mining or drilling for natural resources. Under normal income-tax treatment, producers would recover investment costs over time as resources are depleted. In the case of percentage depletion, the sum of deductions can exceed the actual cost of investment.
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<tr>
<td><strong>Coal Incentive Tax Credit.</strong> Can be claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
<td>2000</td>
<td>GENER</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>23,725</td>
<td>20,253</td>
<td>19,675</td>
<td>19,096</td>
<td>243,360</td>
</tr>
<tr>
<td><strong>Thin Seam Tax Credit.</strong> Allows mining companies operating in the state to get a tax credit for coal mined from thin seams or from areas with a high overburden ratio. The credit is on a sliding scale from 2.25% to 3.75% of the value of the severed coal and based on the thickness of the seam, the ratio of overburden removed to coal severed, and the sulphur content of the coal.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>13,309</td>
<td>12,731</td>
<td>13,309</td>
<td>13,309</td>
<td>215,181</td>
</tr>
<tr>
<td><strong>Sales Tax Incentive for Alternative Fuel or Gasification Facilities.</strong> Exempts eligible taxpayers from the sales taxes paid on tangible personal property used in the process of constructing an alternative fuel or gasification facility (all related to coal).</td>
<td>2008</td>
<td>REFIN</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>4,305,929</td>
</tr>
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</tr>
<tr>
<td><strong>Sales Tax Incentive for Alternative Fuel or Gasification Facilities.</strong> Exempts eligible taxpayers from the sales taxes paid on tangible personal property used in the process of constructing an alternative fuel or gasification facility (all related to coal).</td>
<td>2008</td>
<td>REFIN</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>70,393</td>
</tr>
<tr>
<td><strong>Coal Transportation Expense.</strong> Values used for calculating taxes and royalties due allow deduction of transportation expenses incurred to move coal from mine to a processing plant, loading point, or customer.</td>
<td>1978</td>
<td>TRANS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>110,637,409</td>
</tr>
<tr>
<td><strong>Coal Transportation Expense.</strong> Values used for calculating taxes and royalties due allow deduction of transportation expenses incurred to move coal from mine to a processing plant, loading point, or customer.</td>
<td>1978</td>
<td>TRANS</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,521,009</td>
</tr>
<tr>
<td><strong>Gross-Receipts Tax Exemption for Sales of Natural Gas.</strong> Sales of natural gas by regulated companies in Pennsylvania are exempted from the gross receipts tax normally levied on most sales by utilities. This exemption was introduced in January 2000 to reduce the gas bills of Pennsylvania consumers.</td>
<td>2000</td>
<td>END</td>
<td>NATGAS</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>108,000,000</td>
</tr>
<tr>
<td><strong>Reduced Tax for Thin-Seamed Coal.</strong> Coals seams with a thickness of less than 45 inches pay a 1-2% severance tax instead of the normal rate of 5%. Only new underground mines may</td>
<td>1997</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>WV</td>
<td>60,000,000</td>
<td>60,000,000</td>
<td>-</td>
<td>-</td>
<td>516,000,000</td>
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</tr>
<tr>
<td>Coalbed Methane Exemption. WV exempts coalbed-methane wells placed in service after 1 January 2000 from the state’s severance tax (5% of the gross value of severed coalbed methane). This exemption can be used for five consecutive years and is meant to encourage the capture and use of coalbed methane. Subsequent legislation added a provision making the exemption only applicable to coalbed-methane wells placed in service before 1 January 2009. Qualifying wells can, however, continue to use their five year exemption provided they were placed in service before 1 January 2009.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>WV</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>15,000,000</td>
</tr>
<tr>
<td>Exclusion of Low Volume Oil &amp; Gas Wells. WV wells producing less than one-half barrel per day or less than 5,000 cubic feet per day are exempted from the state’s severance tax (5% of the gross value of severed oil and gas). A similar exemption also applies to natural gas provided for free by producers to surface land owners.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>WV</td>
<td>4,373,252</td>
<td>4,373,252</td>
<td>-</td>
<td>-</td>
<td>49,313,831</td>
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</tr>
<tr>
<td>Exclusion of Low Volume Oil &amp; Gas Wells. WV wells producing less than one-half barrel per day or less than 5,000 cubic feet per day are exempted from the state’s severance tax (5% of the gross value of severed oil and gas). A similar exemption also applies to natural gas provided for free by producers to surface land owners.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>CRUDEOIL</td>
<td>WV</td>
<td>126,748</td>
<td>126,748</td>
<td>-</td>
<td>-</td>
<td>1,686,169</td>
</tr>
<tr>
<td>Industrial Expansion and Revitalization Credit. Eligible companies operating in West Virginia with a tax credit worth 10% of certain qualifying investment expenditures in both real and tangible property. Since 2003, has applied only to power sector; state data indicates it is mostly going to coal utility modernization and pollution control.</td>
<td>NR</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>WV</td>
<td>45,000,000</td>
<td>45,000,000</td>
<td>-</td>
<td>-</td>
<td>270,000,000</td>
</tr>
<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
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<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>CRUDEOIL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Coal Waste Removal Tax Credit. In effect through 2012. Tax credit encouraged investment in facilities that produce fuels from coal and coal dust. OECD was unable to get data, though budget documents indicated only a few facilities benefits. Credit was capped at $18m/year.</td>
<td>1971</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Sales of Electricity. The West Virginia Tax Code exempts the sales of electricity from the Consumers Sales and Service Tax due to the Business and Occupation Tax on businesses providing electricity.</td>
<td>NR</td>
<td>END</td>
<td>ELECTR</td>
<td>WV</td>
<td>150,000,000</td>
<td>150,000,000</td>
<td>-</td>
<td>-</td>
<td>1,370,700,000</td>
</tr>
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</tbody>
</table>

*Where a provision benefits multiple fossil fuels, OECD will include allocated shares for each one as separate line items in their database in order to facilitate fuel-specific totals.

**Key:** Start Date: “NR” = not reported within OECD database; Fuel Cycle Stage: “EXTRACT” = extraction; “GENER” = power generation; “END” = end-use/point of consumption.

**Source:** Data extract from Organisation for Economic Cooperation and Development, Inventory of Support Measures for Fossil Fuels, 2018.
### Table A.3. Direct Outlays to Fossil Fuels by State Governments in the PJM Region

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</thead>
<tbody>
<tr>
<td>Department for Energy Development and Independence</td>
<td>2006</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>7,777</td>
<td>7,850</td>
<td>7,182</td>
<td>7,229</td>
<td>200,043</td>
</tr>
<tr>
<td>Department for Energy Development and Independence</td>
<td>2006</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>1,111,053</td>
<td>1,121,469</td>
<td>1,026,071</td>
<td>1,032,684</td>
<td>17,046,378</td>
</tr>
<tr>
<td>Department for Energy Development and Independence</td>
<td>2006</td>
<td>EXTRACT</td>
<td>COKCOAL</td>
<td>KY</td>
<td>225,169</td>
<td>227,280</td>
<td>207,947</td>
<td>209,287</td>
<td>2,909,096</td>
</tr>
<tr>
<td>Coal Academy Mining Workforce Development</td>
<td>2006</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>17,360</td>
<td>17,360</td>
<td>17,360</td>
<td>17,360</td>
<td>353,308</td>
</tr>
<tr>
<td>Coal Academy Mining Workforce Development</td>
<td>2006</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>2,480,030</td>
<td>2,480,030</td>
<td>2,480,030</td>
<td>2,480,030</td>
<td>30,029,712</td>
</tr>
<tr>
<td>Coal Academy Mining Workforce Development</td>
<td>2006</td>
<td>EXTRACT</td>
<td>COKCOAL</td>
<td>KY</td>
<td>502,610</td>
<td>502,610</td>
<td>502,610</td>
<td>502,610</td>
<td>5,616,977</td>
</tr>
<tr>
<td>Mine Safety and Licensing</td>
<td>NR</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>63,092</td>
<td>60,855</td>
<td>58,347</td>
<td>58,071</td>
<td>1,487,586</td>
</tr>
<tr>
<td>Mine Safety and Licensing</td>
<td>NR</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
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<td>1,689,256</td>
<td>1,681,265</td>
<td>23,111,555</td>
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Koplow Biography
Doug Koplow

**Doug Koplow** is the founder of Earth Track in Cambridge, MA ([www.earthtrack.net](http://www.earthtrack.net)). For nearly 30 years, his work has focused on government subsidization of natural resources, primarily in the energy sector.

Working collaboratively with environmental groups, government officials, and international agencies such as the World Bank and the Organisation for Economic Cooperation and Development, he has helped to improve subsidy measurement and to document the pervasive reach and enormous scale of energy subsidies. Redirecting these hundreds of billions of dollars per year in subsidies is increasingly recognized as an important lever for reducing poverty, transitioning to cleaner energy, and addressing climate change.

Doug’s most recent work has focused on subsidies to fossil fuels and nuclear power. He holds an MBA from the Harvard Business School and a BA in economics from Wesleyan University.
Gramlich Affidavit
I. Introduction

I am an independent consultant specializing in wholesale electricity markets and transmission policy. I have served as a Senior Economist at PJM Interconnection LLC responsible for monitoring its capacity markets, Economic Advisor to a FERC Chairman, and as Senior Vice President of the American Wind Energy Association. My biography can be found at https://gridstrategiesllc.com/about/.

I was asked to assess the two PJM capacity market reform proposals, and compare them to FERC economic policy standards.

II. Just and Reasonable Rates are Based on Prices Resulting from the Interaction of All Supply and Demand, In the Absence of Market Power

It is longstanding Commission policy to have prices set according to the interaction of supply and demand, where market power is absent or mitigated. This has been the general
framework established by FERC and the courts since electricity competition began in the early 1990s.\textsuperscript{1,2,3} This Commission policy has a firm basis in sound economic policy where competition can be relied upon to produce efficient prices as long as market failures are either not present or have been mitigated. There is nothing more fundamental in economics than setting prices where supply and demand intersect.

Market failures, particularly market power, can result in supply and demand setting prices that are not competitive, so policy makers including the Commission often seek to improve efficiency through targeted interventions that correct the market failure. Since competition in electricity began, the Commission has approved a variety of measures to address market power. For example, forms of Reliability Must-Run Agreements exist in each RTO or ISO market to address situations where a specific generator has local market power for services such as providing voltage support at that location. Each RTO/ISO has rules related to economic and physical withholding. These were all developed and approved based on findings of a potential for market power to be exercised. RTOs and ISOs themselves were created largely to mitigate the vertical market power that exists when the transmission system is operated by the same corporate entity as a player in the generation market. Beyond situations of market power, the Commission has relied on competitive forces without further intervention to manage bids or prices.

\textsuperscript{1} Elizabethtown Gas Co. v. FERC, 10 F.3d. 866, 870 (D.C. Cir. 1993).
\textsuperscript{2} “[I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment.” \textit{Tejas Power Corp. v. FERC}, 908 F.2d 998, 1004 (D.C. Cir. 1990).
Previous specific instances of PJM and other RTO/ISO mitigation of state policy has been deemed just and reasonable on the basis of mitigating market power. The Commission’s original order approving the minimum offer prices rule (“MOPR”) in PJM stated, “The Commission finds the Minimum Offer Price Rule a reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self-supply.” The Commission’s later approvals of changes to MOPR stated, “We begin our analysis with a review of the MOPR’s underlying objectives. PJM’s MOPR is a mechanism that seeks to prevent the exercise of buyer-side market power.” Whether market power was present or absent was also the basis for allowing exemptions to state policy mitigation.

III. No Market Power Has Been Demonstrated or Alleged in this Case

In contrast to PJM’s original MOPR proposal and later changes to MOPR which relied on demonstrations of market power and Commission findings that it existed and should be mitigated, here there is no such demonstration and nothing on which the Commission could base a finding. There is no section of the filing or affidavits that provide any assessment of market power.

Many of the public policies at issue in this case relate to renewable energy. There is no assessment of whether these policies specifically are exercises of market power. The Commission has found in the past that renewable energy would be very unlikely to be used to exercise buyer side market power, given its lower capacity value and higher prices. This filing

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provides no analysis to counter that Commission finding. There is no allegation that the renewable resources developed under these policies are being used to exercise any other form of market power.

IV. No other market failures have been demonstrated in this case to justify intervention

It can be sound economic policy to intervene in markets if there is a workable and efficient remedy to other types of market failure, in addition to market power. Market power is the primary market failure of concern in electricity markets, but other potential market failures include barriers to entry, externalities, public goods, and information asymmetries. PJM does not establish that any of these other market failures exist.

A. PJM makes no demonstration of a barrier to entry

PJM does allege a barrier to entry: “if a material fraction of resources price their capacity offers relying on their selective receipt of subsidies, then: ...competitive entry will face a significant added barrier.” PJM provides an example on pages 29-32 to demonstrate this harm. PJM’s assertions may show harm to competitors, not competition. PJM’s conclusion from its example states: “The real world is more complicated than this simple example, but it serves to illustrate a critical point: the state subsidy program is being underwritten by other participants in the wholesale market.” Whether competitors fare better or worse is not the same as harming the competitive process. PJM states that “It undermines robust competition

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9 PJM filing, at p. 4.
because other sellers cannot compete against a substantial subsidy available only to select capacity sellers.” ¹⁰ This is a claim about competitors, not competition. If the goal were to protect some sellers’ ability to compete then policies would be needed to shield market sellers from the effects of low natural gas prices, which are harming the economics of all supply sources. Clearly that would not be appropriate or just and reasonable. Rules should allow entry to be free of barriers, they should not guarantee that entrants are compensated at their expected levels.

PJM acknowledges that competitive entry has been robust. “Since the inception of RPM in 2007, 50,792 megawatts (“MW”) of new generation capacity has been added.”¹¹ Most of this entry has resulted from investment by by entities other than utilities. “By PJM’s estimation, conservatively 70% of this new entry came from merchants, with the remainder brought in by vertically regulated or public power utilities.”¹² PJM stated in its 2016 Resource Investment in Competitive Markets white paper: “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.”¹³ Clearly investors are still investing and entry is open to any and all parties.

B. **PJM makes no demonstration of an externality that the proposals address**

PJM states that through policies such as RPS, “the state is exporting the impact of its subsidy onto other states and potentially ‘crowding out’ resources that other states (with different policy choices) may value.”¹⁴ This might be a negative externality argument, though it

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¹⁰ Id. at p. 46.
¹¹ Id. at p. 2.
¹² Id. at p. 10.
¹⁴ PJM filing, at p. 29.
isn’t described as such and there is no demonstration of inefficiency. When there is an inefficient negative externality, there is a misallocation of resources that represents overall social harm. This overall social harm is distinct from equity or distributional issues, where various market participants may fare better or worse under a policy change. If there is an overall inefficiency then consumers will pay more than a competitive level. No such negative externality effect has been demonstrated here.

There is a positive externality effect of state policies. In a positive externality, third parties outside of the parties to a transaction receive net benefits for which they neither pay nor are paid. In the case of state policies, one state opts to have load in its state pay, through retail rates, for a set of resources. When those resources then supply energy or other services into regional markets, they tend to extend the supply curve and reduce prices. PJM explains this effect numerous times including in the example on pages 29-32. Thus, load in other states actually face lower prices than they otherwise would. If PJM and the Commission are concerned about just and reasonable rates for wholesale customers as the Federal Power Act directs, then if anything these policies are a positive not a negative influence on other states.

C. PJM has made no demonstration of a public good or free-rider problem

Another market failure that can theoretically be present is a public good, also known as a free rider problem. PJM does not mention of public goods or free rider problems in the filing. While there are some references to long term reliability impacts, PJM has made no demonstration that reliability is threatened or is being harmed by state policies. Moreover, there is nothing preventing PJM from procuring the reliability services it needs. If market participants build a portfolio of resources with relatively little capability to provide one service, such as an
operating reserve product, supply and demand for that product will meet at a higher price point, signaling more entry of that capability in the future. That is how markets work, and there is nothing about state policies that interfere with that process.

V. **FERC has traditionally allowed public policies to affect prices, consistent with typical markets**

Prices have been deemed just and reasonable even when public policies affected them. A wide range of state and federal policies have affected quantities and prices in power markets since the inception of US electricity markets. For example, there might not be any nuclear generation in operation were it not for the Price-Anderson Act limiting liability for unit owners. We might not have as much natural gas generation if intangible drilling costs and depletion allowances were not allowed to be deducted under federal tax law. Many states provide incentives for the production of fuels that are used in electricity generation. A large amount of generation participating in markets is part of a state regulatory rate base which affected the development of those sources and influences their ongoing behavior. Health and safety regulations affect firm behavior in electricity markets as with most other industries. Public infrastructure affects delivery costs of most products in most industries. The existence of these policies affects the amount of supply, the cost of that supply, the point at which supply and demand intersect, and the resulting price.

FERC’s regulatory framework has been to set market rules in a manner that accounts for public policies in the same way as other exogenous factors that impact markets. The basic framework of treating public policies like other exogenous factors has generally held true since the establishment of organized wholesale markets. PJM proposals to expand state policy
mitigation in a way that will administratively set prices for gigawatts of supply without any foundation in market power or other market failure, solely because those units are affected by one particular exogenous factor, is a significant change in policy.

Just like any cost of production, a public policy is something that can affect a seller’s willingness to accept or a buyer’s willingness to pay. Quite directly, some generation owners must purchase sulfur dioxide allowances through EPA-regulated markets (which have existed for as long as power markets), and those suppliers may reflect the cost of such allowances in their sales or bid prices. Air emission regulations can affect allowable generation run times. Some policies may tend to raise certain suppliers’ bids and/or prices such as emissions allowances, and others may tend to decrease bids and/or prices, such as renewable energy incentives. For many years, markets have been deemed workably competitive and prices have been deemed just and reasonable by the Commission despite public policies affecting their outcomes.

There are values beyond kilowatt-hours and reliability services that legitimately factor into just and reasonable prices. PJM acknowledges this point: “The theoretical ideal market approach to that issue would be to unbundle the currently unvalued attributes and enable resources to compete to provide those attributes, for example, through a carbon emissions objective embedded in the wholesale market.”15 PJM prefers a different way of pricing environmental services but seems to concede the point that the cost of environmental services can be part of just and reasonable prices.

15 PJM filing, at p. 54.
VI. PJM’s preferred “repricing” approach raises prices above just and reasonable levels

Prices would tend to be higher under PJM’s preferred repricing approach. This effect is intentional, to avoid what PJM considers to be price suppression from state policies. Price-setting is performed in the second stage of the auction by substituting “competitive” (i.e., higher) prices for “subsidized” prices. Inserting higher bids will in most cases lead to higher prices.

Wealth will be transferred from customers to existing suppliers under repricing. Whether those suppliers receive as much as they would have expected but for the state policy is immaterial. The price they receive is above the efficient level with all supply and all demand bidding their marginal opportunity costs as would occur in a competitive market.

Even the subsidized units are paid higher prices than they would under the status quo because they will likely clear in the market and will receive a higher price than would occur without the mitigation.

Capacity repricing does not attract new supply. In PJM’s example, one can see that potential new entrant units that do not clear in the first stage but who would willingly enter at the repriced level, are not taken and would not receive the capacity payments. Thus, the higher price leads to no new supply from which customers could benefit. These resources that do not clear in the first stage are the only resources for which the difference between step one and step two prices would have a meaningful effect on market entry and exit decisions. Thus, all capacity repricing does is ensure that resources that would already be incented to enter or
stay in the market with first step prices are paid an even higher amount, when that higher amount is not necessary to ensure market entry or continued market participation.

Capacity repricing creates an incentive for inefficient economic withholding. Companies that own portfolios of generation would benefit from the higher re-priced price level. They would have more incentive than under the status quo to use their units on the margin to withhold output or bid higher in order to affect that price. Under PJM’s current rules, if that resource makes an offer based on its true costs, it will clear only where doing so allows the resource owner to earn a profit or at least break even. But under the repricing proposal, the offer price of that resource becomes important even where that resource has no chance of earning a profit in the market. There is a chance that the resource will not clear, but will nevertheless be the resource that sets the price for resources that do clear.

VII. MOPR-Ex raises prices above just and reasonable levels

PJM’s alternative approach, MOPR-Ex, is similar to re-pricing in terms of raising capacity market prices in response to state policies. By artificially increasing the cost of certain low-cost resources bidding into the market based on arbitrary distinctions about what kind “out of market” payments can legitimately be factored into their offer price, the extended MOPR will cause a higher-cost resources to be marginal, thereby increasing capacity market clearing prices. It also forces customers to pay twice for the capacity they need; once for the state-required payment, and again in the higher resulting capacity price from extending MOPR.

VIII. The proposals both violate the Commission principle of shifting risk to suppliers

The Commission’s recent order on ISO-New England’s CASPR proposal stated that one principle for capacity markets is to “shift risk as appropriate from customers to private
capital.”¹⁶ That has been a core element of electricity restructuring and competition and is important for long-run efficiency. PJM states that the status quo with state policies “shifts risk from private capital to customers, because resource owners are insulated from the financial consequences of a resource that cannot, based on its economics, clear in a competitive auction, with customers (and other wholesale market participants . . .) bearing the costs of keeping the resource in operation.”¹⁷ However the effect is the opposite of what PJM claims because the two proposed mechanisms shield investors from risks that are properly borne by investors, and returns those risks to customers.

Risks of public policy changes are borne by investors in electricity markets, just like all other markets. Any product subject to health, environmental, safety, or other forms of regulation can have its market opportunities impacted by changes in these regulations. Product prices and stock values are changed every day in other industries. Investors in industries where there is a lot of regulation, such as telecommunications and pharmaceuticals, pay close attention to state as well as federal regulation, as they should in electricity. Risks do not disappear if RTOs mitigate state policies,¹⁸ they are simply shifted from investors to customers in a zero sum game.

PJM’s position is based on what it thinks investors should know about: “Investors and market participants also are more likely to have better understanding of and familiarity with acts of Congress, compared to individual state action focused on a particular unit or project.” Yet electricity is not the only industry where state policies matter, and it should not be a

¹⁷ PJM filing, at p. 46.
¹⁸ PJM filing, at p. 71.
surprise to investors that state policies matter in an industry where jurisdiction over generation is left to states under the Federal Power Act.

IX. The proposals may harm investor confidence more than they help

The Commission recently stated that a goal of capacity markets “is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates.” Investor confidence does not come from shielding market participants from all risks. Rather investor confidence comes more from having stability and clarity in laws and policies so they can reasonably predict the types of changes that may occur. The two proposals filed by PJM upend the traditional roles of states in making electricity resource choices that has been firmly established in the regulatory structure from its beginning, which widens rather than narrows the range of outcomes investors must consider.

If public policies were to be mitigated, deterred, or otherwise adjusted by the Commission rather than accounted for in the same manner as other exogenous factors, there would be no clear boundary governing when the Commission might intervene and when it might not. Policies vary in many dimensions: state vs. federal, capital cost vs. operating cost support, forms of insurance vs. direct cost support, environmental vs. economic development vs. other social objectives, forms of zoning and resource access vs. economic factors, and more. Sometimes impacts are direct and sometimes they flow indirectly from upstream sectors. Some policies such as Renewable Portfolio Standards do not pick a single technology or resource but allow a measure of competition. PJM provides no reasoned principle separating state policies

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19 CASPR Order at P 21.
warranting mitigation and not. With no boundary between what policies are mitigated and which are not, there is no regulatory certainty.

PJM’s suggested mechanisms create a situation in which determinations need to be made on which policies count as “subsidies” and how to mitigate each one. Such decisions, subjective as they are, could easily be changed over time so there would be little regulatory certainty. Both proposals require determinations about which policies are “actionable.” There could very easily be disagreements about which policies are actionable, as there is no principled distinction or bright line provided to guide investors’ decisions.

Investor confidence would be higher if the traditional boundaries governing RTO intervention in competitive markets in response to exogenous factors were maintained. Commission policy has been clear that prices would be set where supply and demand meet, if market power is absent or has been mitigated. Thus, it would have been reasonable for investors to assume that state policies would not be mitigated unless they crossed the line into buyer-side market power or some other form of market power. An expansion of FERC’s policy of mitigating state policies significantly changes the line between state and federal roles in wholesale markets and moves the line to an ambiguous place given the slippery slope of deciding which interventions count as “out-of-market revenue sources”, likely creating more uncertainty than it resolves.

These proposals add a whole new category of regulatory risk investors need to consider. Investors must consider state and federal environmental, health, and safety regulations and legislation as they affect electric industry participants as a normal course of doing business. These policy-making bodies can be very subjective in what policies they choose to put in place.
If RTOs remained objective engineering bodies as they were originally designed, that would contain regulatory risk to the traditional sources rather than create a whole new source of hard-to-predict subjective policies.

Investor confidence would also suffer from the lengthy process of interpreting new rules once they are implemented. Under either proposal there will be many questions and details to be clarified in tariffs over time.

X. Conclusion: with no economic policy justification for mitigation, and higher prices, the proposal leads to inefficiently high prices

There is no market power or other market failure demonstration that either of PJM’s proposed approaches remedy. The purpose of mitigating market power, internalizing externalities, and preventing free-riding in the case of public goods is to correct a well-defined market failure so that supply and demand can set efficient prices. If there is no demonstrated market failure, then administratively raising prices is moving prices to a less efficient point. Inefficient prices over the long-term harm customers.

No value accrues to customers from the higher prices. Entry is not attracted, environmental performance does not improve, and there are no other market or non-market values that have been shown to benefit customers. They simply pay more, and wealth is transferred to existing suppliers.

The two capacity market proposals decrease efficiency by harming states’ ability to internalize environmental externalities. States have always had environmental responsibilities and can enact policies to internalize externalities. Internalizing externalities increases efficiency. Thus, these proposals to reduce their ability to do so reduce market efficiency.
UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection LLC

Verification of Robert Gramlich

On Behalf of the Sustainable FERC Project, Natural Resources Defense Council, and Sierra Club

I, Robert Gramlich, declare under penalty of perjury that the attached affidavit is true and correct to the best of my knowledge, information and belief.

__________________
Rob Gramlich

Execution Date: May 7, 2018
Wilson Affidavit
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.  Docket No. ER18-1314-000

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE PROTESTS OF
DC-MD-NJ CONSUMER COALITION, JOINT CONSUMER ADVOCATES,
AND CLEAN ENERGY ADVOCATES
AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE PROTESTS OF
DC-MD-NJ CONSUMER COALITION, JOINT CONSUMER ADVOCATES,
AND CLEAN ENERGY ADVOCATES

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AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE PROTESTS OF
DC-MD-NJ CONSUMER COALITION, JOINT CONSUMER ADVOCATES,
AND CLEAN ENERGY ADVOCATES

I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have over thirty years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission (“Commission”), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, Russia, and other regions. With regard to the PJM system, I have also been involved in a broad range of other market design and planning issues over the past several years.
4. With regard to the capacity market design issues that are the subject of this proceeding, I have been involved in these issues in PJM, New England, California, the Midwest, and other regions. Since PJM Interconnection, L.L.C. (“PJM”) proposed the Reliability Pricing Model (“RPM”) capacity construct in 2005, I have prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues, including the minimum offer price policies addressed in this docket. I submitted comments in the Commission’s technical conference on state policies and wholesale markets in Docket No. AD17-11.1 I also actively participated in the Capacity Construct Public Policy Senior Task Force (“CCPPSTF”) stakeholder process that led to this filing.

5. On April 9, 2018, PJM filed proposed changes to its tariff to address the potential impacts on RPM prices of resources receiving state subsidies (“PJM Filing”). This affidavit was prepared at the request of the Maryland Office of People’s Counsel, New Jersey Division of Rate Counsel, and District of Columbia Office of People’s Counsel (“DC-MD-NJ Consumer Coalition”), Illinois Citizens Utility Board, Illinois Attorney General, Delaware Division of the Public Advocate, West Virginia Consumer Advocate Division, Kentucky Attorney General, and Indiana Office of Utility Consumer Counselor (“Joint Consumer Advocates”), and Sierra Club and Natural Resources Defense Council (“Clean Energy Advocates”). My assignment was to evaluate the need for and likely impacts of the proposed changes to RPM.

II. Overview and Recommendations

A. The Issue: Capacity Price Formation in the Presence of Policy Resources

6. When states financially support the development or retention of resources with environmental or other attributes that satisfy public policy objectives not valued in the wholesale markets (hereafter, “public policy resources”), the Commission has found that the resulting “out-of-market” revenues provided to the public policy resources potentially create a conflict between three objectives for forward capacity constructs:2

1. that all resources, including public policy resources, should receive capacity supply obligations and payments, recognizing their contributions to resource adequacy, so consumers don’t “pay twice” for duplicative excess capacity;
2. that capacity prices should not be suppressed by the presence of public policy resources, which price suppression could discourage “competitive”, in-market resources, and compensate existing resources unfairly; and
3. that the capacity construct should clear a reasonable total quantity of capacity at a reasonable total cost.

7. The never-ending struggles around changes to minimum offer price (“MOPR”) rules in PJM and elsewhere reflect, to a large extent, that different stakeholders disagree as to the impact of public policy resources on capacity prices, and place different priorities on these conflicting objectives. Not surprisingly, capacity sellers and RTOs tend to emphasize objective #2 while consumer interests place more importance on objectives #1 and #3.

8. The PJM Filing proposes two alternative packages of changes to RPM, both intended to support higher RPM price outcomes in the presence of resources receiving state policy support. PJM’s preferred package is its Capacity Repricing Proposal (hereafter, “PJM’s Repricing Proposal”). The alternate proposal, MOPR-Ex, was primarily developed by the PJM Independent

Market Monitor, Monitoring Analytics, LLC. PJM claims that either proposal is just and reasonable (p. 42) and that Commission action is needed now (p. 18).

**B. There is No Present Need for Comprehensive Revision or Expansion of the RPM MOPR Rules**

9. Resource adequacy has been easily achieved in the PJM footprint in recent years, with large amounts of excess capacity cleared through RPM despite numerous retirements. There has been substantial entry and exit each year, large amounts of uncleared resources, and more and more offers at prices close to clearing prices (the supply curves are becoming more gently sloped). This means that RPM has substantial ability to absorb new resources of all types, while maintaining clearing prices within a range that balances entry and retirements. The RPM market is not nearly as fragile as suggested by PJM and other proponents of major tariff changes to support higher capacity price levels.

10. PJM’s estimates of the potential impacts of new or retained resources on RPM prices (PJM Filing, pp. 28-29) ignore these dynamics and, as a result, greatly overstate the potential impacts. New entrants generally offer at low prices, whether or not they receive state policy support; and all new entry at low prices has the same potential impact on RPM prices. However, as market participants plan their entry and exit choices, they take into account the anticipated supply/demand balance and the anticipated actions of other market participants that affect that balance. As a result, despite entry and exit each year, the RPM supply curves end up being quite similar year to year.

11. Both of PJM’s proposals (the Repricing Proposal, MOPR-Ex) represent fundamental changes to the RPM MOPR rules, which are designed to support higher capacity prices by imposing minimum offer prices on certain resources. Minimum offer price rules are market interventions that lead to administrative pricing. It should be a goal of the design of such
interventions that they have the minimum necessary impact for the minimum necessary duration, allowing the market to return to market-based pricing. Both proposals ignore the market’s dynamic ability to absorb incremental resources with clearing prices maintaining, or quickly returning to, the levels that balance supply and demand, entry and exit.

C. PJM’s Repricing Proposal is Fatally Flawed and Would Be Harmful to the Market and Costly to Consumers

12. PJM’s Repricing Proposal contains three characteristics that I consider to be fatal flaws – each individually warrants rejection of the proposal. The first fatal flaw has to do specifically with RPM, while the other two are market design fatal flaws of a more generic nature.

1. The first fatal flaw is that PJM’s Repricing Proposal establishes an auction clearing price and quantity pair that does not lie on the auction’s sloped Variable Resource Requirement (“VRR”) capacity demand curve; as discussed in detail below, under very likely circumstances, the auction result would lie well above the VRR curve. This violates a bedrock principle of capacity market design – auction outcomes must lie upon the agreed sloped demand curve. As noted below, the Commission has seen a proposal with this feature before, and rejected it on this basis. A proposal with this characteristic would require, among other things, a fundamental reconsideration of the interpretation and role of the sloped capacity demand curve, and of its shape and position. No such reconsideration has occurred.

2. The second fatal flaw is that PJM’s Repricing Proposal divorces the determination of who clears in the auction from the determination of what price those winners will be paid, which will badly distort resources’ offer prices. Functioning markets and workable market and auction designs share the characteristic that a seller’s offer price will determine whether the seller will make a sale, and also the minimum price the seller might receive. This disciplines offer conduct, pushing sellers to offer based on cost. PJM’s Repricing Proposal will determine who clears the auction based on one supply curve (“Stage 1”), but will determine the price to be paid based on a potentially very different supply curve (“Stage 2”) that, as I will
show, is very likely to result in a much higher clearing price in Stage 2. This will create strong incentives for sellers in a broad cost range near the likely Stage 1 clearing price to “race to the bottom” – offer below their cost to try to clear in Stage 1, knowing that they will get paid the much higher price established in Stage 2. And higher-cost sellers that won’t enter the “race to the bottom” will realize that their offer prices are not meaningless; they can contribute to higher Stage 2 clearing prices (that will be earned by all affiliated cleared resources) by “clearing out the top” and offering at the highest prices allowed. I am not aware of any market or auction that has this characteristic except perhaps under trivial circumstances (and as shown below, the impact in this instance is far from trivial). This design characteristic – one process determines who clears, a quite different one the price – is unworkable and should be considered an auction design non-starter.

3. The third fatal flaw is related to the second one. As noted, under quite reasonable assumptions, the Stage 2 clearing price can be well above the Stage 1 price that resources must offer under to be chosen in the auction. That means that the Stage 2 clearing price would likely be set by the offer from a resource that knew it would not be receiving a capacity commitment. In addition, as noted above, such resources have incentives to offer above cost, to support a higher Stage 2 clearing price. Thus, the Stage 2 clearing price is arguably quite arbitrary and not cost-based or the result of a workably competitive market mechanism. While it futile to attempt to administratively reconstruct the “competitive” price that would occur without subsidies – the market would adapt to that alternate world, adjusting entry and exit decisions – the Stage 2 price is a particularly flawed attempt to determine such a price. This design characteristic – a price that will determine billions in capacity payments may be set by an offer from a resource that had nothing at stake in selecting its offer price, and indeed had incentives to inflate its offer price – should also be considered an auction design non-starter.

13. I simulated the results of PJM’s Repricing Proposal for the RTO Region using actual demand curves and supply curves based on recent auctions. Even assuming market participants naively do not adjust their offers based on the incentives created by PJM’s Repricing
Proposal, if 5,000 MW (the minimum amount) is repriced, it would raise RPM prices and the cost to consumers by 28%; if 9,000 MW is repriced, it would raise prices and cost by 50%. Under the assumption that half of the market participants would adjust their offers due to the clear incentives created by the PJM Repricing Proposal, prices and cost would increase by 66% if 9,000 MW is repriced, or by 42% if only 5,000 MW is repriced. These examples are explained in detail and summarized in Figures 1 to 5 and Table 1 below.

14. The incentives created by the PJM Repricing Proposal would raise RPM prices and costs; as explained below, the incentives would also cause the RPM supply curves to become steeper in the relevant range near likely clearing prices. This is a highly undesirable result. Over recent years, RPM supply curves have become more gently sloped, which contributes to more competitive conduct and relatively stable prices over time. These conditions provide stronger incentives for investment in the PJM markets. The PJM Repricing Proposal would lead to steeper supply curves and more volatile prices, weakening investment incentives and increasing risk premiums.

15. PJM suggests that market participants may not act on the incentives resulting from its Repricing Proposal, because the RPM Stage 1 and Stage 2 prices and price differences might not be sufficiently predictable, so such action would be “speculative.” This would seem to leave PJM, market participants and the Commission hoping for market uncertainty and volatility, because the market design would only work acceptably under such conditions.

D. The Proposed Applicability and Duration of Mitigation Are Excessive Under Both Proposals (Repricing and MOPR-Ex)

16. In addition to the issues raised above, both of PJM’s proposals also share the following characteristic: Both call for mitigating (repricing) resources with actionable subsidies for an unlimited period, without regard to how many years the market may have had to adjust to
and absorb the resource, either before it enters the market, or after. In applying market interventions that result in administrative prices (such as MOPRs and repricing do), the goal should be to apply the minimum intervention for the minimum period, such that the market can absorb and adjust to the resource, and return to market-based pricing without interventions as soon as possible. MOPRing or repricing a resource year after year, despite plenty of time for the market to absorb the resource, leads to artificial prices that do not reflect the true supply/demand balance, and that delay the market’s adjustment to the resource. Any tariff rules to expand the mitigation or repricing of resources with actionable subsidies should limit the mitigation or repricing in the following two ways:

1. Resources with actionable subsidies that meet criteria indicating that the market has been able to absorb them should not be mitigated or repriced. The criteria would have to do with a) how far in advance the resource’s entry was known, and perhaps b) the size of the resource compared to its zone of entry.

2. When mitigation or repricing does apply to a resource, the duration of the mitigation or repricing should be limited, and should again depend upon the advance knowledge and the size of the resource compared to the zone of entry.

17. These changes would be more consistent with the recently-approved provisions of ISO New England’s capacity construct to address policy resources, under which such resources are treated as existing resources and no longer mitigated once they clear in the new substitution auctions.³

18. The remainder of this affidavit is organized as follows. The next section discusses PJM capacity market conditions and the ability of the market to absorb new entry and retirements without impacts on prices. It suggests that there is not a crisis calling for urgent action on the

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³ 162 FERC ¶ 61,205 Order on Tariff Filing, issued March 9, 2018 in Docket No ER18-619.
issues raised in PJM’s Filing. The final section evaluates PJM’s Repricing Proposal, and describes in greater detail the three fatal flaws noted above, with numerical examples.

III. PJM’s Capacity Market and Policy Resources

A. Resource Adequacy is in Good Shape in PJM; There is No Imminent Crisis

19. As PJM acknowledges, year after year, RPM clears substantial amounts of excess capacity, at prices well below the administrative Net CONE values. Resource adequacy in PJM is in good shape. This is largely due to flat loads, moderate natural gas prices, and declining costs for natural gas and renewable resources, as PJM also acknowledges (p. 11). These circumstances are not expected to end anytime soon. New resources are likely to continue to push into the PJM market through RPM, even if, as has been the case in recent years, many higher-cost existing resources are unwilling to retire.

B. The PJM Capacity Market has become Increasingly Dynamic and Competitive with Substantial Ability to Absorb New Resources of All Types

20. As the PJM Filing states (p. 37), “A properly designed competitive market will address excess or shortage positions over time through the actions of competitive market participants.” Over the past several years, RPM base residual auctions have seen a substantial volume of entry and exit in each auction. Specifically, over the past six delivery years, the base residual auction has seen over 35,000 MW of incremental generation resources, while each auction
has also had 11,000 to 18,000 MW of uncleared resources;\(^4\) and over six years from June 1, 2011 through June 1, 2017, just under 25,000 MW of installed capacity deactivated in PJM.\(^5\)

21. Market participants generally will select the timing of retirements and new capacity additions in anticipation of the RPM supply-/demand balance and price level; if RPM prices are expected to rise, some retirements may be delayed or relatively more new entry may be offered, and if prices are expected to be soft there might be more retirements or some new entry may be delayed. Such adjustments have kept RPM prices within a limited range over the past several years despite the retirements and new entry. In addition, various short lead time resources that can efficiently take on RPM obligations, or not, on a year-by-year basis depending upon need and prices (such as some imports, some demand response, and resources that are economic on an energy-only basis) also tend to buffer the RPM price changes from year to year.

22. When certain additional resources are expected to enter or exit the market (be it “competitive” or sponsored resources), market participants will take these changes into account in planning the timing of retirements, other new entry, and other actions that affect the balance of supply and demand. If the additional resources or retirements are anticipated well in advance, it is reasonable to expect that they are fully anticipated and absorbed by market participants’ adjustments, and have minimal, if any, impact on capacity prices.

23. In particular, with regard to resources with state policy support of some kind, states generally pursue lengthy regulatory processes before any procurement of new resources to meet state mandates. In most cases, state policies result in quantities of new capacity that are relatively

\(^4\) PJM, 2020/2021 RPM Base Residual Auction Results, Tables 6 and 8.

small and known well in advance of the RPM auctions in which they first participate. To the extent
the market has had ample time to see that these resources were coming, it is reasonable to assume
that the incremental resources are reflected in market participants’ various entry and exit decisions,
and do not affect price appreciably.

24. While the entry of the public policy resources will likely correspond to some delay
of other new entry, acceleration of retirements, or adjustments by resources able to enter and exit
on a year-by-year basis, this displacement is a natural consequence of the policy, perhaps even an
objective of the policy.

25. When, on the other hand, an incremental (or retained) resource was not fully
anticipated by the market (due to, for example, a relatively last-minute state action affecting a large
resource), it could have some impact on the RPM auction. However, even in this case, after a few
delivery years it should again be the case that the market has adjusted to and absorbed the
additional capacity, with RPM prices again finding the point that balances supply and demand,
entry and exit. So while the resource may have had an impact initially, it is reasonable to assume
that after it has participated in a few auctions there is no further lasting impact on RPM prices.

C. PJM’s Estimates of the Impacts of State-Supported Resources on RPM Prices
Are Vastly Overstated

26. The PJM Filing at pp. 28-29, citing to the affidavit of Mr. Adam J. Keech, Executive
Director, PJM Market Operations (Attachment E), alleges that state subsidies can result in large
impacts on RPM clearing prices. For example, citing to auction sensitivity analyses, Mr. Keech
suggests (p. 2) that adding 6,000 MW in the Rest of RTO region (outside of the Mid-Atlantic)
would reduce RPM prices by 21%. These estimates are based on oversimplified calculations that
vastly overstate the potential impacts of incremental resources. PJM’s Independent Market Monitor has made similar claims, using the same flawed approach.

27. As a preliminary observation, note that new resources, whether subsidized or “competitive”, generally offer at low prices that are very likely to clear in the RPM auctions; and all new entry that offers at low prices and clears, whether subsidized or “competitive”, has exactly the same impact, if any, on RPM clearing prices. So the 50,792 MW of new generation capacity that has been added from 2010 to 2017 (PJM Filing, p. 9) would all have had the same impact on RPM prices, if any, as any future new entry, whether subsidized or “competitive”.

28. If incremental resources have huge impacts on RPM prices (as PJM and Mr. Keech allege), how can RPM prices have remained well above zero? The answer was explained in the previous section: as entry and exit occur, other resources are adjusting entry and exit plans, resulting in a buffering of RPM clearing prices. The RPM supply curves are less steeply sloped than in the past, which moderates the price impact of changes in supply or demand. More important, market participants respond to other participants’ entry and exit decisions by adjusting their own entry and exit plans. As a result, the RPM supply curves generally end up in about the same place year to year, and result in roughly similar prices, despite various new resources and removed resources.

29. By contrast, Mr. Keech’s calculations simply add or remove resources, assuming all other resources’ offer prices and quantities are unchanged, and ignoring how the market might adjust to the change in resources, if known in advance, with adjustments to new entry or retirements (among other adjustments, as described in the previous section). Mr. Keech’s simple calculations would be accurate for a change in a resource that catches the market totally by surprise – for example, a last-minute action allowing a resource to participate in the auction that the market
expected would not participate. Such a “shock” could potentially have the impacts suggested by Mr. Keech’s calculations, for a single auction. However, by the next RPM auction, the market would have reacted to and absorbed the resource, with its presence reflected in market participants’ forecasts of prices and needs, and undoubtedly reflected in some participants’ choices to adjust their actions or timing.

30. The fact that there has been so much entry (and exit) through RPM over the past several years, while RPM prices have remained in roughly the $70 to $170/MW-day range, reflects this dynamic – market participants are adjusting their entry and exit timing based on anticipated market supply/demand balance and resulting prices. In particular, gas-fired combined cycle units are apparently economic at recent RPM price levels, and will enter at such levels and keep prices from rising higher. There are many more new plants (mainly combined cycle) eligible for participation in RPM than participate and clear in each auction, suggesting that some plants may be holding off and waiting for additional retirements and/or somewhat higher prices.

31. Mr. Keech also discusses the economic principles behind resources’ offer price choices, and what constitutes a competitive offer (Attachment E, p. 4). His discussion is rather vague; he refers to a resource’s “cost” or “revenue need” without indicating exactly which of the many cost concepts used by economists, and over what time frame, he has in mind. However, he apparently discusses going-forward costs, and makes no reference to opportunity costs. As such, his view contradicts PJM’s position in the Capacity Performance docket, accepted by the

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6 For instance, in the 2020/2021 RPM base residual auction, while 12,161.0 MW of new resources received Competitive Entry exemptions from the MOPR, only 2,675.6 of these MW cleared the auction. 2020/2021 RPM Base Residual Auction Results report, p. 5.
Commission, that under Capacity Performance, any RPM offer up to Net CONE times the Balancing Ratio is competitive, due to the opportunity cost of taking on a commitment.7

32. The PJM Filing also includes an over-simplified and flawed example, not supported by an affidavit, upon which it alleges that a state subsidy program “is being underwritten by other participants in the wholesale market.” First, note again that any entry, including purely merchant entry, would potentially lower market prices in the same manner, and, therefore, would also be “underwritten” by other market participants, under PJM’s flawed logic in this example. Furthermore, the example includes a new entrant that needs $45/MW-day to enter, and incorrectly suggests that subsidized entry would harm the entrant. If there is no subsidized resource, the market clears at the entrant’s $45/MW-day offer, but with the subsidized resource the entrant does not clear. The entrant, according to the example, is indifferent between these two outcomes (neither makes any net revenue over cost), but the PJM Filing incorrectly suggests the subsidized entry results in harm to the entrant, stating (p. 32) that the new entrant “forgoes the $45/MW-day it would have received.”

33. To summarize, because the market is dynamic and market participants are adjusting their entry, exit, and other plans taking into account the anticipated supply/demand balance and prices, it is unclear what impact, if any, a new resource has on RPM prices, especially if its entry has been anticipated well in advance. PJM’s impact estimates would, at best, be applicable only to resources that catch the market by total surprise.

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7 155 FERC ¶ 61,157, Order on Rehearing and Compliance, P 184 (noting that the Commission accepted PJM’s Capacity Performance default offer cap (Net CONE times the Balancing Ratio) on the grounds that it is based on a reasonable estimate of a low-end competitive offer, after accounting for all marginal costs, opportunity costs, and risks associated with assuming a Capacity Performance commitment).
D. Many of the Potentially Subsidized Resources Would Receive Payments to Reflect Value Not Captured in the PJM Markets

34. PJM suggests there is an imminent crisis calling for immediate Commission action, referring (at p. 24) to “a growing trend among the PJM states... to intervene in resource selection with targeted subsidies.” Notably, the state programs PJM identifies all exclusively pertain to zero-carbon resources (p. 25, noting zero-emission credit programs, off-shore wind procurement, and renewable portfolio standards). Anticipated subsidies generally pursue legitimate policy goals of geographically broad value, such as carbon reduction and encouraging innovation, that are not valued in the PJM markets. While the preferred approach, in the face of such environmental and learning externalities, is generally to bring those values into the markets, in the meanwhile, subsidies to address such externalities arguably represent a second-best approach that enhances market efficiency.

35. Furthermore, these policies, which generally either support entry over time by new zero carbon resources, or further retention of zero carbon resources that have been in the market for decades, typically result from lengthy, transparent regulatory processes. The new zero carbon resources will typically be added to the market at a steady pace that is known to the market well in advance, and can easily be absorbed (especially since these resources are typically assigned capacity values well below their installed capacity ratings). The existing zero carbon resources that may be retained by such programs are already in the market so generally do not need to be absorbed.
IV. Evaluation of PJM’s Repricing Proposal

A. PJM’s Repricing Proposal: Description

36. The basic idea of PJM’s Repricing Proposal (described in the PJM Filing, pp. 59-96), is as follows. When repricing is triggered (when the quantity of cleared resources with Actionable Subsidies exceeds 5,000 MW across the RTO, or 3.5% of the reliability requirement in any modeled zone; PJM Filing, p. 52), the RPM Base Residual Auction software would be run to solve the auction twice, in two “stages.” In what PJM calls Stage 1, no resources are repriced; so capacity resources with Actionable Subsidies (hereafter, “CRAS” resources) would presumably be offered at low prices and “clear” the Stage 1 auction. Stage 1 would determine which resources will receive capacity supply obligations (“CSOs”); all resources that clear in Stage 1 would receive CSOs for their cleared quantities.

37. Then Stage 2 of the auction would be run, for the sole purpose of determining the price to be paid to the resources that cleared in Stage 1. In Stage 2, PJM would reprice the CRAS resources (substitute “Actionable Subsidy Reference Prices” for the CRAS resources’ voluntary offer prices), while all other resources’ offers are unchanged, with the goal of removing the impact of subsidies on the resulting Stage 2 clearing price. The repricing would generally associate very high offer prices to all or nearly all CRAS resources, pushing them out of the relevant portion of the supply curve. As a result, the supply curve would shift to the left for Stage 2, which would in general result in a higher clearing price. Then all resources that cleared in Stage 1, including any CRAS resources that cleared in Stage 1, would get CSOs and be paid the Stage 2 clearing price. The clearing price from Stage 1, and the cleared quantity from Stage 2, are not used.

38. Note that under PJM’s Repricing Proposal there likely would be resources that offered at prices below the Stage 2 clearing price, but above the Stage 1 clearing price. Since these resources (sometimes referred to as “in-between” or “tweener” resources) were offered at prices
below the Stage 2 clearing price (which is intended to be a “competitive” price), they are presumably economic; but under PJM’s proposal, having failed to clear in Stage 1, they do not receive CSOs.

39. With regard to the three conflicting objectives in MOPR design identified above, PJM’s Repricing Proposal at least nominally addresses the first two objectives, while sacrificing the third objective:

1. All CRAS resources that clear get CSOs (as a result of Stage 1); and
2. The clearing price is set to a purportedly “competitive” level due to the repricing of CRAS resources (Stage 2); however
3. The reasonable total cost objective is compromised (discussed further below).

40. There are of course various other details to PJM’s Repricing Proposal; these are not discussed here as they are not important to my evaluation of the proposal.

B. History of Proposals for Two-Stage Capacity Market Repricing

41. The New England ISO raised the possibility of such a two-stage capacity pricing approach (also sometimes called “two-tiered”) in 2010, in a proceeding pertaining to its minimum offer price rules. The Commission rejected the proposal, finding that it would have cleared a quantity of capacity in excess of the Net Installed Capacity Requirement, thereby violating what it referred to as a “bedrock principle” of the New England capacity market (which at the time was designed to clear exactly the Net Installed Capacity Requirement).8

42. Two-stage approaches were again proposed in New England in 2016, in the context of the New England “IMAPP” (Integrating Markets and Public Policy) stakeholder process. The proposals did not receive sufficient support, and stakeholders ultimately settled on an entirely different approach.

43. PJM first proposed its two-stage capacity market concept in a white paper in June, 2016. PJM’s proposal was discussed at a Grid 20/20 event in August, 2016, and it remained one of the many proposals considered throughout the CCPPSTF stakeholder process in 2017. Two other two-stage proposals were also considered by CCPPSTF. In the final CCPPSTF poll, PJM’s proposal gained only 26% support, while the other two-stage proposals gained less than 20% support.

44. I am not aware of any market in which such a two-stage capacity pricing proposal has been implemented.

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C. PJM’s Repricing Proposal: Evaluation

45. This section of my affidavit evaluates the market design elements of PJM’s Repricing Proposal and their potential impacts on RPM, describing in further detail the three fatal flaws in the proposal. To help this discussion, I have prepared examples that illustrate the potential impacts of PJM’s Repricing Proposal under realistic assumptions, focusing on the RTO Region. For these examples I used the VRR capacity demand curve and Net CONE value for the 2021-22 base residual auction. I used an RTO region supply curve with shape and slope similar to the supply curves from recent base residual auctions, as reported by The Brattle Group in its

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Quadrennial Review report. The supply curve (depicted in Figure 1, based on a graphic from the Quadrennial Review report) is relatively gently sloped (compared to earlier delivery years), with a slope of $1.25/MW-day/1000 MW up to a price of $100/MW-day, and a slope of $7/MW-day/1000 MW at prices above $100/MW-day up to $200/MW-day (while a case could be made for various other supply curve shapes, the nature of the results discussed below is not sensitive to this detail). I shifted the supply curve to give a clearing price near $100/MW-day, which I consider

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13 The Brattle Group, Fourth Review of PJM’s Variable Resource Requirement Curve, prepared for PJM, April 19, 2018, Figure 13, p. 42.
to be a reasonable starting point. Although higher than the clearing price from the most recent auction result available at the time of this testimony ($76.53/MW-day, for the 2020/2021 delivery year), both the average, and median, RTO clearing prices over the past five delivery years are roughly $100/MW-day.\footnote{14}

46. Figure 2 shows the “base case” auction result with these assumptions, assuming no mitigation or repricing of resource offer prices. The clearing price is $102.80/MW-day, with a cleared quantity of 161,474 MW, resulting in a total market annual capacity cost of $6.1 billion.\footnote{15} The base case represents the result of “Stage 1” under PJM’s Repricing Proposal, in which the CRAS resources are not mitigated; it also represents the status quo, assuming all CRAS resources would either not be subject to mitigation, or would qualify for an exemption.

47. I then assumed a quantity of CRAS resources (with actionable subsidies) of 9,000 MW. This assumption is supported by the PJM Filing, Attachment F, Affidavit of Dr. Anthony Giacomoni (suggesting 4,969 MW of “around-the-clock” capacity to meet renewable targets, and potentially similar amounts of zero emissions credits; pp. 6-10). This assumption represents about five percent of the total offered unforced generation capacity in RPM, which is usually about 180,000 MW.\footnote{16} I assumed these CRAS resources are re-priced in a manner that effectively removes them from the relevant portion of the supply curve; that is, to prices well above clearing prices under any of my examples.


\footnote{15} For brevity and simplicity in these examples, the reported cost will simply be the clearing price times the cleared quantity times 365 days; this calculation ignores, among other complexities, that some of the obligation clears in zones at higher prices, and some is self-supplied or hedged.

\footnote{16} 2020/2021 RPM Base Residual Auction Results, Table 5 p. 17.
1. **Fatal Flaw #1:** Under PJM’s Repricing Proposal, the base residual auction price and quantity result are not consistent with the auction capacity demand (VRR) curve and would result in excessive cost to consumers.

48. Figure 3 illustrates the result of “Stage 2” under PJM’s proposal, with 9,000 MW repriced (and no change in conduct).\(^\text{17}\) Under these assumptions, the Stage 2 result is a clearing price of $154.53/MW-day, an increase of 50 percent compared to the base case. This results in a total annual market capacity cost of $9.1 billion, also a 50% increase compared to the base case.

\(^{17}\) Rather than suggesting where in the upper reaches of the supply curve the re-priced 9,000 MW might end up, Figure 3 (and later figures) simply shifts the entire supply curve by 9,000 MW.
This example shows that the PJM proposal can substantially increase the cost to consumers, under what I consider to be reasonably likely assumptions about the supply and demand curves, and CRAS resources.

49. The Stage 2 price corresponds to a quantity of 159,800 MW on the VRR curve; however, under PJM’s proposal, this price will be paid to all resources that cleared in Stage 1 (161,474 MW). Figure 3 also shows the cleared price (from Stage 2) and the cleared quantity (from Stage 1) under PJM’s proposal. This price, quantity pair lies above, not on, the VRR curve.

50. In the 2010 New England case mentioned above, the Commission rejected ISO New England’s two-stage proposal because it would clear a total quantity in excess of the Net Installed Capacity Requirement, and thereby violate a “bedrock principle” of the capacity
construct. In a capacity construct with a sloped demand curve (such as RPM, or ISO New England’s current construct), the analogous bedrock principle is that the auction result lie on the sloped demand curve; the sloped demand curve identifies the universe of acceptable auction clearing outcomes. PJM’s proposal, by resulting in a cleared quantity and clearing price that are not on the VRR curve, violates the bedrock principle, as applied to a sloped demand curve.

51. In rejecting ISO New England’s two-stage proposal for violation of a bedrock principle, the Commission did not have to evaluate the evidence and testimony regarding other fatal flaws of the proposed two-stage pricing approach. While Fatal Flaw #1 is sufficient to reject PJM’s Repricing Proposal, the next fatal flaw is an even more serious problem.

2. **Fatal Flaw #2: Under PJM’s Repricing Proposal, incentives to submit competitive offers are distorted and will lead to undesirable conduct that affects quantity and price, and further raises the cost to consumers**

52. The second issue is that the proposal reflects a fundamentally flawed market approach that would badly distort resources’ choices with regard to offer prices, leading to unintended and undesirable results and further raising cost.

53. Under the current auction rules (or the rules of just about any well-structured auction or market process), a resource’s offer price determines both whether the resource will be chosen in the auction, and also the minimum price the resource will be paid. This generally leads a resource to offer at the price the resource requires in order to want to clear in the auction. That is, the resource’s offer price should be the price needed to make taking on a CSO worthwhile. If the auction clears at a price above a resource’s offer price, it clears and gets a CSO, and is satisfied with this result because the price is enough (likely more than enough) to make taking on the CSO worthwhile. If, instead, the auction clears at a price below the resource’s offer price, the resource does not receive a CSO and is again satisfied with this result, because at that clearing price it does
not want a CSO. An owner might determine the price its resource “needs” to make a CSO worthwhile based on its avoided cost, or an opportunity cost concept, or some other analysis, it does not matter; if the auction is well-structured, the incentive is to make an offer based on the price considered needed (setting aside market power considerations). For the discussion here, this price will be referred to as the resource’s “cost-based” offer price, recognizing that this may be an opportunity cost or have some other basis.

54. However, under the PJM Repricing Proposal, a resource’s offer price does not serve in this role. Under this proposal, the resource will get a CSO and be paid the higher Stage 2 price if and only if its offer is below the lower, Stage 1 clearing price. In the example above, if the resource offers at less than or equal to $102.80/MW-day (the Stage 1 price; Figure 2), it clears, and will be paid $154.53/MW-day (the Stage 2 price; Figure 3).

55. Now suppose the resource’s cost-based offer price would be, say, $115/MW-day. If the resource offers at this price, it will not clear in Stage 1, and will not receive a CSO or payment. But the Stage 2 price (that it won’t get, because it didn’t clear in Stage 1) is well above the $115/MW-day price it needs. So if the owner suspects that Stage 1 may clear in the $90 to 110/MW-day range, and that Stage 2 will very likely clear above $115/MW-day (as in the example), the owner might quite rationally choose to offer somewhat lower than its $115/MW-day price, even though that is below the price it needs. With this strategy the owner would increase the chance that the resource will clear in Stage 1 and get paid the higher Stage 2 clearing price, without much risk of clearing and receiving a price less than its $115/MW-day cost. This strategy is of course more profitable than the initial approach of offering at $115/MW-day (the cost-based offer) and failing to clear.
56. So to the extent 1) it is likely that there will be a substantial wedge between the Stage 2 and Stage 1 prices (which, as shown below, will be the case when there are enough CRAS resources to trigger mitigation), and 2) the likely range of the auction Stage 1 clearing price is reasonably predictable, resources whose cost-based offers are close to or somewhat above the expected Stage 1 clearing price have incentives to lower their offer prices, to increase their chances of clearing in Stage 1 and earning the Stage 2 price. This incentive issue has frequently been noted and is called the “race to the bottom.” To the extent this conduct occurs, Stage 1 will clear a somewhat larger quantity, at a lower Stage 1 price, than if all resources submitted their undistorted cost-based offers.

57. The “race to the bottom” – resources lowering their offer prices below cost, in order to clear the auction Stage 1 to earn the higher Stage 2 price – is one bad incentive created by PJM’s proposal. There is a second one, applicable to higher-cost resources. Now consider a resource whose cost-based offer price is $140/MW-day. Suppose the owner considers it too risky to lower the offer price enough to be likely to clear in Stage 1 (that is, down to the $100/MW-day range, in my example). The owner chooses to not join the “race to the bottom” that he would likely not win (and could potentially regret, if he does clear, but Stage 2 clears below his cost, $140/MW-day). So does the owner offer the resource at $140/MW-day? If the owner accepts that the resource won’t clear in Stage 1 and won’t receive a CSO, it would appear that the selected offer price won’t make any difference.

58. However, while the selected offer price for this resource won’t determine whether the resource will clear (it won’t), the offer price could very well affect the Stage 2 clearing price. Suppose the owner anticipates that Stage 2 will likely clear at a price in the $140 to $170/MW-day range, above his offer price, if the offer is based on his cost. If he instead offers at, say, $190/MW-
day, this removes the resource from the Stage 2 clearing result, and leads to Stage 2 likely clearing at a somewhat higher price than it would have. If the owner has only the one resource, this still makes no difference to the owner. But if the owner has other capacity that will clear Stage 1 in the auction and earn the Stage 2 price, then the owner will likely increase profits by offering this resource not at its cost-based $140/MW-day price, but at a higher price (consistent with applicable market power mitigation rules), in order to support a higher Stage 2 clearing price that will be earned by the rest of the owner’s portfolio. This second incentive problem, applicable to higher-cost resources, has been called “clear out the top”. While resources with costs reasonably close to the anticipated range of Stage 1 clearing prices will be tempted to join the “race to the bottom”, higher cost resources that do not enter the race, especially if affiliated with other resources that will clear, will be tempted to “clear out the top” and help Stage 2 clear at a higher price.

59. Note also that while the owners of CRAS resources can apply for lower, resource-specific repricing based on a resource’s avoidable cost (PJM Filing, pp. 82-85), in many cases owners would have no incentive to do so; this is another perverse incentive resulting from PJM’s Repricing Proposal. While a CRAS resource’s actual cost might be considerably lower than the applicable Reference Price, if the resource is unlikely to clear in Stage 1, the owner would generally prefer a higher rather than lower price imposed on the resource, to support a higher Stage 2 clearing price earned by the owner’s other resources that will clear in the auction.

60. I simulated the potential impact of these incentives issues, on the base of the numerical example discussed above. For the “race to the bottom”, I assumed half of the resources with costs in the $80 to $130/MW-day range would lower their offer prices by 20%, to increase their chances of clearing in Stage 1, while half the resources would not change their offer prices. This assumption leads to the Stage 1 clearing result shown in Figure 4. The Stage 1 cleared
quantity increases by 167 MW, and the Stage 1 clearing price declines by $5.17/MW-day, compared to the results assuming no change in offer conduct. If sellers were more aggressive (if more were lowering their prices, or by larger amounts), the impact on the Stage 1 price and quantity could be larger.

61. I simulated the potential conduct of higher-cost resources by assuming that half of the resources with costs in the $130 to $170/MW-day range would raise their offer prices by $50/MW-day. The Stage 2 clearing results are shown in Figure 5. The Stage 2 clearing price now
increases to $170.70/MW-day,\(^{18}\) a further 10% increase due to the conduct. The market cost under this scenario is now $10.1 billion, an 11% increase over the repricing result with no change in offer behavior, and 66% higher than the cost under the status quo. The resulting RPM auction price and quantity represent a point even further above the sloped VRR curve, due to the conduct.

62. Table 1 summarizes the results of these analyses. In addition to the 9,000 MW repricing assumption shown in the figures and discussed above, Table 1 also shows results for 5,000 MW of repricing (for this scenario, it was assumed half the resources with cost below

\(^{18}\) Note that this clearing price is still well below the applicable Net CONE value, $321.57/MW-day. If Net CONE is substantially reduced in future auctions this would scale the VRR curve, and these examples, downward but not change the fundamental conclusions.
$110/MW-day would “race to the bottom”, while half the resources with cost above this level would “clear out the top”). Even this minimum amount of repriced resource leads to substantial differences in price and cost, and large enough price differences to influence bidding behavior.

<table>
<thead>
<tr>
<th>RTO Region, 9,000 MW Repriced:</th>
<th>Quantity (MW)</th>
<th>Price ($/MW-day)</th>
<th>Cost ($ bil./year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (current rules; = Stage 1)</td>
<td>161,474</td>
<td>$102.80</td>
<td>$6.06</td>
</tr>
<tr>
<td>Repricing, No Conduct Change, Stage 2</td>
<td>159,800</td>
<td>$154.53</td>
<td>$9.11</td>
</tr>
<tr>
<td>Repricing, Conduct Change, Stage 1 Clearing</td>
<td>161,641</td>
<td>$97.63</td>
<td>n.a.</td>
</tr>
<tr>
<td>Repricing, Conduct Change, Stage 2 Clearing</td>
<td>159,277</td>
<td>$170.70</td>
<td>$10.07</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>RTO Region, 5,000 MW Repriced:</th>
<th>Quantity (MW)</th>
<th>Price ($/MW-day)</th>
<th>Cost ($ bil./year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case (current rules; = Stage 1)</td>
<td>161,474</td>
<td>$102.80</td>
<td>$6.06</td>
</tr>
<tr>
<td>Repricing, No Conduct Change, Stage 2</td>
<td>160,545</td>
<td>$131.50</td>
<td>$7.75</td>
</tr>
<tr>
<td>Repricing, Conduct Change, Stage 1 Clearing</td>
<td>161,585</td>
<td>$99.38</td>
<td>n.a.</td>
</tr>
<tr>
<td>Repricing, Conduct Change, Stage 2 Clearing</td>
<td>160,092</td>
<td>$145.50</td>
<td>$8.58</td>
</tr>
</tbody>
</table>

Note: The results shown in italics (Stage 1 prices and costs, and Stage 2 quantities) are not used if repricing is triggered. The Stage 2 cost is calculated using the Stage 1 quantity.

63. The PJM Filing notes these incentive issues, but it notes them and dismisses them in a single paragraph, with only the following discussion (p. 58, citations omitted), and there is no discussion of the incentive issues in either attached affidavit:

“Some stakeholders have raised a concern that this effect of repricing could distort participants’ bidding behavior; for example, encouraging sellers to bid low so as to guarantee they clear in the face of a subsidized low-price offer. To the extent this posits that unsubsidized sellers would offer below their own net costs, so as to commit to provide PJM capacity for a full Delivery Year at a loss, such concerns are speculative, to say the least. It is worth noting, moreover, that in the current PJM capacity market, the high-cost, marginal sellers likely will be less efficient legacy units (with a limited future economic life), as opposed to the new entry units classically assumed to be at the margin.”
64. PJM has been aware of the incentive issues raised by its Repricing Proposal since it was first proposed, in mid-2016. For example, the PJM re-pricing proposal was presented and discussed at the August 18, 2016 PJM-sponsored event, Grid 20/20: Focus on Public Policy and Market Efficiency. At that event, Stu Bresler, PJM’s Senior Vice President – Operations and Markets, noted that stakeholders had raised the two incentive issues, and acknowledged the possibility that they could represent fatal flaws. Throughout the twenty-two meetings of the CCPPSTF, the incentives issues were repeatedly raised by various stakeholders, including stakeholders representing public power, capacity seller, and consumer interests (perhaps among other interests). However, PJM never responded to these concerns with any discussion or analysis; PJM’s only response has been to dismiss the concern as speculative, as it has in the PJM Filing. In a question-and-answer document responding to questions about its proposal, PJM summarily dismissed the incentive issue as follows:

“How do you think your proposal will impact bidding behavior?
Response: Minimum impact as the MW commitment is based on “as offered” with no adjustments.”

65. While the fact that the commitments are based on “as offered with no adjustments” prevents some types of distortion of bidding behavior, it does not prevent behavior following the clear incentives created by PJM’s Repricing Proposal, as discussed in detail above.


66. Although PJM has failed to provide any cogent response to concerns about bidding behavior, it could be argued that the incentive problems could be unimportant because RPM prices are somewhat unpredictable. While RPM prices have been somewhat variable (although less so recently), the market design should be robust and workable from a long-run, equilibrium point of view. If the RPM rules are reasonably stable over time, clearing prices should become more predictable. I believe RPM prices have been sufficiently stable recently such that many market participants would find it profitable to act according to the incentives created by PJM’s Repricing Proposal, as suggested in the examples above. In any case, market participants and stakeholders should not be left hoping for uncertainty and volatility, because PJM has implemented a market design that only performs acceptably under such conditions.

67. It could also be argued that this incentive problem would be unimportant if the Stage 1 and Stage 2 prices are not very different, as would be the case if repricing does not shift the supply curve very much. However, as Table 1 above shows, if the minimum 5,000 MW is repriced such that it fails to clear in Stage 2, this can still drive a substantial wedge between the Stage 1 and Stage 2 prices, if the supply curve is shaped as in recent auctions. Again, the market design should be robust under a range of reasonably likely circumstances, including circumstances under which the quantities of CRAS resources may be large.

68. PJM dismisses the incentive issues as “speculative”; I do not consider the conduct assumptions adopted in my examples at all speculative. Perhaps more difficult to explain would be: faced with such an auction mechanism, why would profit-maximizing sellers not behave in this manner? If it is likely that repricing will be triggered (and this will generally be known before the auction), it is easy to roughly estimate the wedge the CRAS resources will create between the Stage 2 and Stage 1 prices. Much of the PJM capacity is owned in large portfolios, and these
owners would rationally segment their resources into those they desire to clear (“race to the bottom”) and those they do not expect to clear (“clear out the top”).

69. PJM apparently does not propose to publish the Stage 1 clearing prices. That would mean that the determination of which resources clear the auction and are selected to provide capacity would be based on a non-transparent, unpublished clearing price. And while not publishing the Stage 1 price could contribute to keeping some market participants guessing about the price level they must beat to clear Stage 1 (detracting adjusting offer prices), market participants with portfolios could easily discover this price, by, say, ensuring that at least a small bit of the portfolio is offered within every $5/MW-day price interval through the range of likely clearing prices.

70. Furthermore, while perhaps many market participants would not adjust their offers very much in the first auctions held with such rules, the problem would likely increase over time. The RPM auctions are held every year. Market participants might approach the new market design somewhat tentatively in the first year or two, but over time it should be expected that conduct consistent with the incentives will increase. Note that in my example, some resources that did not engage in the conduct have regrets – that is, they would have a better outcome, had they pursued the conduct (lowering offer prices to clear in Stage 1, or raising offer prices to contribute to a higher clearing price in Stage 2). But no resources that engaged in either conduct have regrets. Thus, it should be expected that year to year, the distortion of offer prices would only increase.

71. As a result of these incentives and the resulting rational conduct, the RPM supply curves would become steeper and steeper over time (as suggested by the figures above). This is

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22 See proposed PJM Tariff, Attachment DD § 5.11 (Option A).
exactly the opposite of the result that is desired – gently sloped supply curves lead to competitive outcomes and relatively stable capacity prices over time, resulting in stronger investment incentives and weaker incentives to exercise market power. Steeper supply curves lead to more volatile prices, greater incentives to physically or economically withhold to raise prices, and weaker incentives for investors.

72. In dismissing the concerns about the distortion of offer price incentives, PJM states (as quoted above), “To the extent this posits that unsubsidized sellers would offer below their own net costs, so as to commit to provide PJM capacity for a full Delivery Year at a loss, such concerns are speculative, to say the least.” As my examples have shown, with realistic supply curves, there will be a large difference in the Stage 1 and Stage 2 prices when repricing is triggered, and sellers that lower their offer prices will not be at much risk of providing capacity “at a loss.”

73. PJM also suggests, in the above quote, that the price-setting offers may be from higher-cost existing units that are close to retirement rather than from new entrants. But the distortion of offer incentives is the same for existing or new units – if the likely Stage 2 price is attractive, it makes sense to lower the offer price in order to clear in Stage 1, if that is not too much of a reach. And if clearing in Stage 1 is too much of a reach, it makes sense to instead bid high to support a high Stage 2 clearing price, if there is affiliated generation in the auction.

74. Finally, I note that concerns about “bid shading” were raised in regard to ISO New England’s “CASPR” (Competitive Auctions with Sponsored Policy Resources) mechanism, and the Commission was not persuaded that these concerns rendered the proposal unjust and unreasonable.23 However, the distortion of offer incentives that would result from PJM’s proposal

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23 162 FERC ¶ 61,205 Order on Tariff Filing, issued March 9, 2018 in Docket No ER18-619, P. 85.
is easily distinguished from the CASPR circumstances, and is much more serious. One key difference is that the bid shading concern around CASPR had to do with opportunities following the forward capacity auctions; the forward capacity auction retains the necessary feature that the price used to clear resources is the price the cleared resources will be paid. By contrast, under PJM’s Repricing Proposal, if repricing will be triggered, resources can be confident there will be a substantial wedge between the Stage 1 price that determines who clears, and the Stage 2 price that will actually be received.

3. **Fatal Flaw #3: Under PJM’s Repricing Proposal, the ultimate capacity price is arbitrary and not the result of a workable market mechanism**

75. The third fatal flaw in PJM’s Repricing Proposal has to do with the formation of the Stage 2 price that would be paid to all resources clearing in Stage 1. The Stage 2 clearing price would likely be set by an offer from a “competitive” resource (resources with actionable subsidies, that are repriced, are likely out of the money). Assuming the Stage 1 and Stage 2 prices are substantially different (which, as I have explained, is very likely to be the case when there are resources with actionable subsidies), the owner of the competitive resource that sets the Stage 2 price very likely knew the resource would not clear in Stage 1 and would not receive a CSO. Accordingly, the Stage 2 price would be set by an offer from a resource that had nothing at stake in the auction and in selecting its offer price (except for the incentive, described above, to inflate the offer price to support a higher Stage 2 clearing price, which only makes things worse). Thus, the Stage 2 price, which becomes a rate upon which billions of dollars in capacity payments will be based, is rather arbitrary and does not result from a workably competitive mechanism.
4. PJM’s Repricing Proposal raises additional concerns as applied to capacity zones, of which some are quite small and/or have concentrated ownership

76. My illustrative examples have pertained to the very large and relatively competitive RTO Region. PJM’s Repricing Proposal would apply to all zones modeled in RPM, of which, for the 2021/22 base residual auction there will be a total of fifteen. The modeled zones range in size from the Mid-Atlantic zone (about half the size of the RTO Region), down to DPL South, with a Reliability Requirement of 2,907 MW; eight zones are under 10,000 MW. Repricing would be triggered by 3.5% CRAS resources (350 MW, in a 10,000 MW zone), and any particular quantity of repriced resource will have a proportionally larger impact in smaller zones. Zonal supply curves can be quite steep, which would lead to relatively large differences between Stage 1 and Stage 2 quantity and price clearing results.

77. In addition, the smaller a zone, the larger the impact of any particular change in offer behavior. Ownership of capacity is generally much more concentrated in zones than in the RTO Region, with single sellers owning 50% or more of the capacity in some zones. Potential changes in conduct due to the PJM Repricing Proposal should be an even greater concern in zones.

78. PJM’s Repricing Proposal could potentially result in repricing, and resulting high capacity prices, in some zones, while repricing is not triggered, and capacity prices remain at moderate levels, in adjacent or surrounding zones. This could result in large differences in capacity prices between zones in which the actual capacity supply and demand circumstances may be very similar. This would send confusing and misleading price signals, and result in unwarranted differences in the cost to consumers.

D. Applicability and Duration of Mitigation

79. The final issue with regard to PJM’s Repricing Proposal (which is equally applicable to the MOPR-Ex proposal) has to do with the applicability and duration of repricing or
MOPR mitigation. As explained in Section III above, when the market has known well in advance that certain additional resources will be entering the market (whether “competitive”, state sponsored, or of any other type), market participants will have factored those resources into their estimates of the supply/demand balance and RPM clearing prices, and adjusted their entry and exit plans accordingly. Therefore, resources known well in advance do not affect price when they enter; they are already “baked in”. Repricing or MOPRing such resources distorts the RPM picture by effectively removing from the auction resources that are known to be present.

80. Furthermore, any repricing or application of the MOPR that is applied should last for no more than a few years, after which (if not sooner) the market will have fully absorbed the resource. The goal in applying repricing or the MOPR, as with any market intervention, should be to apply the minimum intervention for the minimum period, so that the market can return to pricing based on the true supply/demand balance without administrative interference.²⁴

81. This concludes my affidavit.

²⁴These concepts were proposed and discussed in the CCPPSTF process, but not included in either of PJM’s proposals. See, for instance, Wilson, James F., Proposed Path for Policy Resources based on Substantial Advanced Notice, CCPPSTF meeting September 11-12, 2017.
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SUMMARY  

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.  

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.  

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.  

EDUCATION  

  MS, Engineering-Economic Systems, Stanford University, 1982  
  BA, Mathematics, Oberlin College, 1977  

RECENT ENGAGEMENTS  

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.  
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.  
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.  
- Evaluation of proposals for natural gas distribution system expansions.  
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.  
- Cost-benefit analysis of a new natural gas pipeline.  
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.  
- Panelist on a FERC technical conference on capacity markets.  
- Affidavit on the potential for market power over natural gas storage.  
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
• Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
• Participated in a panel teleseminar on resource adequacy policy and modeling.
• Affidavits on opt-out rules for centralized capacity markets.
• Affidavits on minimum offer price rules for RTO centralized capacity markets.
• Evaluated electric utility avoided cost in a tax dispute.
• Advised on pricing approaches for RTO backstop short-term capacity procurement.
• Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
• Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
• Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
• Participated on a panel teleseminar on natural gas price forecasting.
• Affidavit evaluating a shortage pricing mechanism and recommending changes.
• Testimony in support of proposed changes to a forward capacity market mechanism.
• Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
• Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
• Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
• Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE
Principal
• Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
• Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
• Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
• Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
• Analyzed impacts and potential damages of natural gas migration from a storage field.
• Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
• Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
• Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
• Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
• Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
• Evaluated market power issues raised by a possible gas-electric merger.
• Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission (“FERC”) policy.
• Prepared an expert report on damages in a natural gas contract dispute.
• Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
• Prepared testimony evaluating natural gas procurement incentive mechanisms.
• Analyzed the need for and value of additional natural gas storage in the southwestern US.
• Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
• Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
• Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
• Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
• Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
• Advised a major US utility with regard to the Federal Energy Regulatory Commission’s proposed Standard Market Design and its potential impacts on the company.
• Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
• Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
• Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
• Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
• Reviewed the reasonableness of an electric utility’s wholesale power purchases and sales in a restructured power market during a period of high prices.
• Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
• Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
• Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
• Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
• Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
• Authored a report on the role of regional transmission organizations in market monitoring.
• Prepared market power analyses in support of electric generators’ applications to FERC for market-based rates for energy and ancillary services.
• Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
• Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
• Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
• Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy’s Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.


Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (the Program on Natural Monopolies, a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.
Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992


- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Evaluated oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS


In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company’s Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.


Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.


Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.


Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.


PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.


PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.


Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

PUBLISHED ARTICLES

*Forward Capacity Market CONEfusio*... Journal Vol. 23 Issue 9, November 2010.


OTHER ARTICLES, REPORTS AND PRESENTATIONS


*Panel: Demand Response*, Organization of PJM States Spring Strategy Meeting, April 9, 2018.


*Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR*; moderator; Infocast’s Mid-Atlantic Power Market Summit, October 24, 2017.


IMAPP “Two-Tier” FCM Pricing Proposals: Description and Critique, prepared for the New England States Committee on Electricity, October 2016.


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The Regional Transmission Organization’s Role in Market Monitoring, report for the Edison Electric Institute attached to their comments on the FERC’s NOPR on RTOs, August, 1999.


PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

April 2018
Wilson CV
James F. Wilson
Principal, Wilson Energy Economics

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Bethesda, Maryland 20814 USA

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Cell:  (301) 535-6571
Email: jwilson@wilsonenec.com
www.wilsonenec.com

SUMMARY
James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

- MS, Engineering-Economic Systems, Stanford University, 1982
- BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE
Principal
- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission (“FERC”) policy.
- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructuring Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission’s proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility’s wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators’ applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.
Project Manager
- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy’s Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

Project Director, Moscow, Russia
Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (the Program on Natural Monopolies, a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):
- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.

Independent Consultant stationed in Moscow, Russia, 1991–1996
Projects for the WORLD BANK, 1992-1996:
- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.
Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Evaluated potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS


In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company’s Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.


Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.


Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.


PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.


PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.


Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

PUBLISHED ARTICLES

Forward Capacity Market CONEfusion, Electricity Journal Vol. 23 Issue 9, November 2010.


Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.


OTHER ARTICLES, REPORTS AND PRESENTATIONS


Panel: Demand Response, Organization of PJM States Spring Strategy Meeting, April 9, 2018.


Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR; moderator; Infocast's Mid-Atlantic Power Market Summit, October 24, 2017.


IMAPP “Two-Tier” FCM Pricing Proposals: Description and Critique, prepared for the New England States Committee on Electricity, October 2016.


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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

April 2018
Goggin Affidavit
I. Introduction

1. I am an independent consultant specializing in wholesale electricity markets and transmission policy. Previously, I have served as the Senior Director of Research for the American Wind Energy Association (AWEA). My biography can be found at https://gridstrategiesllc.com/about/.

2. I was asked to calculate the cost of the redundant capacity that would be procured due to PJM’s MOPR-Ex proposal. PJM’s MOPR-Ex proposal threatens to exclude nuclear and renewable resources that benefit from state policies from participation in the capacity market. My estimate calculates the rough costs should that occur.
II. PJM’s MOPR-Ex proposal would impose significant costs on consumers by procuring redundant capacity to replace capacity excluded from the capacity market

3. I have determined that PJM’s MOPR-Ex proposal would result in the procurement of roughly between $14 billion and $24.6 billion of redundant capacity over roughly the next 10 years. These costs would utility be borne by PJM customers, translating to a cost of between $216 and $379 for each of the 65 million people in the PJM footprint.

4. These estimates assume that all resources receiving revenue pursuant to state programs would be excluded from participation in the capacity market under MOPR-Ex. The range in costs accounts for the fact that it was not possible to precisely determine whether resources procured as part of state Renewable Portfolio Standard (RPS) policies would be able to use the exemptions in the MOPR-Ex proposal to participate in the capacity market. The lower-end $14 billion cost assumes resources contracted under state RPSs are able to use the exemptions and participate in the capacity market. The higher-end $24.6 billion cost assumes those resources are barred from participation in the capacity market. It is likely that some, but not all, renewable resources will be able to use the exemptions, so the actual cost impact from the MOPR-Ex proposal will most likely falls between those two numbers.

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1 The roughly 10-year time horizon reflects the timeline on which most currently adopted RPSs and nuclear support policies will operate.
2 This cost per customer calculation is not intended to be a precise estimate of what retail customers would pay, which would require detailed modeling of impacts on capacity market clearing prices and a deep examination of how capacity costs are reflected through to retail rates in different states. Rather, it is simply intended to give a sense of the scale of PJM’s proposal with relation to its impact on retail customers.
3 The proposed exemptions are listed here: https://www.pjm.com/-/media/committees-groups/committees/mc/20180125/20180125-item-02-mopr-ex-proposal.ashx
A. Calculating the lower-end cost impact from PJM’s MOPR-Ex Proposal

5. To determine the lower bound of cost impacts from PJM’s proposal, I considered only the capacity of the five Illinois nuclear plant in PJM and two nuclear plants in New Jersey.\(^4\) The nameplate capacity for the five Illinois nuclear plants in PJM – Braidwood, Byron, Dresden, LaSalle, and Quad Cities generation stations - total 11,276 MW.\(^5\) The nameplate capacity for the two nuclear plants in New Jersey that will continue to operate after 2019 - Hope Creek and Salem- total 3,631 MW. PJM calculates that nuclear plants have 98.397% availability for purposes of computing the share of nameplate capacity that receives credit in the capacity market,\(^6\) so those seven nuclear plants have an accredited capacity of 14,668 MW in PJM’s capacity market.

6. To calculate the cost of replacing that capacity, I assume that enough natural gas combustion turbines are built to provide an equal amount of accredited capacity. I assume the use of combustion turbines (CTs), instead of combined cycle (CC) power plants, because while CC plants are built to provide both energy and capacity, CTs are built almost entirely to provide capacity and not energy. This is evidenced by their very low capacity factors.\(^7\) Therefore, CTs better represent the cost of replacement capacity than CC plants do.

\(^{4}\) As of the time of this filing, legislation to support New Jersey’s nuclear power plants and advance greater penetration of renewable resources remains pending. This analysis assumes that Governor Murphy will sign this legislation into law.

\(^{5}\) Clinton Power Station is located within the MISO footprint in Illinois.

\(^{6}\) https://www.pjm.com/-/media/planning/res-adeq/res-reports/2012-2016-pjm-generating-unit-class-average-values.ashx?la=en

7. PJM calculates that gas combustion turbines have a capacity market availability rate of 88.687%,\(^8\) so 16,539 MW of nameplate CT capacity would be needed to provide the equivalent 14,668 MW of accredited capacity. Using a regional CT installed cost of $848,500/MW, the midpoint of the $799,000-898,000/MW range reported by Brattle for the PJM region,\(^9\) indicates a cost of $14.033 billion for 16,539 MW of nameplate capacity. This $14 billion is thus the low-end estimate, assuming that all renewable resources are able to use the MOPR-Ex RPS exemption to participate in the capacity market and only nuclear plants receiving state subsidies are impacted by the MOPR-Ex proposal.

B. Calculating the higher-end cost impacts of PJM’s MOPR-Ex Proposal

8. The high-end estimate includes the associated capacity and replacement costs of the seven nuclear plants discussed above, as well as all renewable capacity that will be built under state RPS policies after this year (2018). This high-end estimate reflects the rough cost of MOPR-Ex without the RPS exemption. To determine the amount of RPS demand remaining pursuant to currently enacted or imminently pending state policies, I used the AWEA 2017 assessment database, which compiles data concerning these policies to inform members on the amount of market demand.\(^{10}\) I updated that assessment to account for pending legislation in New Jersey that is likely to be adopted imminently,\(^{11}\) Maryland state laws and regulations (to reflect Offshore Renewable Energy Credits (ORECs) that were awarded), and Illinois (because AWEA does not group Illinois with PJM for the purposes of its state RPS analysis).

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\(^8\)https://www.pjm.com/-/media/planning/res-adeq/res-reports/2012-2016-pjm-generating-unit-class-average-values.ashx?la=en


\(^10\)https://www.awea.org/tps2017

\(^11\) N.J. Stat. § 48:3-49 et seq. (last revision S.2313)
9. Maryland law calls for up to 2.5% of state electricity demand to be met by offshore wind, which would require just over 1.53 million MWh of ORECs. The state awarded 368 MW of ORECs to two projects in 2017, so those resources would be exempt from MOPR-Ex as they were contracted before the end of 2018. Assuming a 40% capacity factor (CF) for offshore wind, that leaves around 70 MW of remaining offshore capacity under the OREC program. At a 27% capacity value, that equals 18.83 MW of accredited capacity.

10. New Jersey recently updated its state RPS to include 3,500 MW of offshore wind, a solar carveout equal to 5.3% of electricity demand, and an overall RPS level of 50%. At 27% capacity value (per PJM’s capacity value above), the offshore requirement equates to 945 MW of accredited capacity. The 5.3% solar carveout equals 3,868,298 MWh of RECs or the annual production of 2,598 MW at the region’s typical 17% CF. This is equal to 1,559 MW of accredited capacity at PJM’s 60% capacity value.

11. After the offshore and solar carveouts, there would be 9,204,661 MWh of outstanding RECs that would likely be almost entirely provided by a mixture of onshore wind and solar. Historically, onshore wind has accounted for around 75% of New Jersey’s RPS procurement. I conservatively assume that that ratio will continue. However, if onshore wind captures a lower share than 75%, as is likely given recent cost trends for solar PV, then my estimate underestimates the capacity value of NJ’s RPS resource mix, as onshore wind’s 13%

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capacity value is markedly lower than the capacity value of other renewable resources. Using a 75% onshore wind and 25% solar mix to meet the remaining RPS demand equals 2,440 MW of nameplate onshore wind capacity and 1,545 MW of nameplate solar. This is equivalent to 317 MW and 927 MW of accredited capacity at PJM’s 13% and 60% capacity values.

12. The incremental renewable build under the Illinois RPS is driven through the procurements of 3 million additional wind RECs and 3 million additional solar RECs through 2030. Using a 17% CF for PV,\(^{17}\) as assumed by the state, and a 37.6% CF for wind, as assumed by AWEA’s report based on observed trends, yields nameplate capacities of 911 MW of wind and 2,015 MW of solar. This is equal to 118 MW and 1,209 MW of accredited capacity respectively.

13. In 2017, AWEA had projected that all parts of PJM, except Illinois had enough remaining RPS demand to drive 10,500 MW of new wind capacity. However, AWEA assumed that only 5,400 MW was likely to be met by wind, with the remainder likely met by solar due to recent cost and deployment trends.\(^{18}\) Because the New Jersey and Maryland ORECs are accounted for separately above, I subtracted from AWEA’s 5,400 MW of likely wind builds both the 1,600 MW of new wind AWEA had projected would have been driven under the old NJ RPS and the roughly 70 MW of remaining OREC capacity I accounted for above. That leaves 3,730 MW of remaining nameplate wind builds driven by RPS requirements, or at PJM’s 13% capacity value, a total of 485 MW of accredited wind capacity.

14. To calculate the remaining non-wind RPS demand in the region, I also subtracted out AWEA’s calculated 2,133 MW of wind-equivalent MW\(^{19}\) of new renewable capacity demand

\(^{17}\) https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/20180227-REC-Pricing-Model-Update.pdf
\(^{18}\) https://www.awea.org/rps2017
\(^{19}\) AWEA calculates the required wind capacity assuming a regional wind capacity factor of around 34%.
remaining under the old New Jersey RPS. Subtracting out the other 3,800 MW of wind capacity (3,730 MW from preceding paragraph plus the remaining 70 MW of Maryland ORECs) leaves 4,567 MW of wind-equivalent RPS driven capacity left to be accounted for. I assumed solar provides this remaining non-wind RPS supply, given recent cost trends for solar and the fact that the region’s resource potential for other eligible renewables, like biomass, has already largely been developed. Since the regional capacity factor of solar is half that of wind (17% CF versus a 34% CF for eastern PJM), the 4,567 MW of non-wind capacity equals 9,134 MW of solar capacity. At PJM’s 60% capacity value, that equals 5,480 MW of accredited capacity.

<table>
<thead>
<tr>
<th>Nameplate Capacity (MW)</th>
<th>Capacity Value</th>
<th>Accredited Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NJ nukes</td>
<td>3,631</td>
<td>98.397%</td>
</tr>
<tr>
<td>IL PJM nukes</td>
<td>11,276</td>
<td>98.397%</td>
</tr>
<tr>
<td>MD post-2018 ORECs</td>
<td>70</td>
<td>27.00%</td>
</tr>
<tr>
<td>NJ generic RPS, wind</td>
<td>2,440</td>
<td>13.00%</td>
</tr>
<tr>
<td>NJ generic RPS, solar</td>
<td>1,545</td>
<td>60.00%</td>
</tr>
<tr>
<td>NJ solar carveout</td>
<td>2,598</td>
<td>60.00%</td>
</tr>
<tr>
<td>NJ offshore wind</td>
<td>3,500</td>
<td>27.00%</td>
</tr>
<tr>
<td>Incremental IL RPS demand 2019-2030, wind</td>
<td>911</td>
<td>13.00%</td>
</tr>
<tr>
<td>Incremental IL RPS demand 2019-2030, solar</td>
<td>2,015</td>
<td>60.00%</td>
</tr>
<tr>
<td>Other post-2018 state RPS demand, wind</td>
<td>3,730</td>
<td>13.00%</td>
</tr>
<tr>
<td>Other post-2018 state RPS demand, solar</td>
<td>9,134</td>
<td>60.00%</td>
</tr>
<tr>
<td><strong>Total Accredited Capacity (MW)</strong></td>
<td><strong>25,727</strong></td>
<td></td>
</tr>
</tbody>
</table>

15. As shown in the table above, these state-supported nuclear and RPS resources have a combined 25,727 MW of accredited capacity. at PJM’s 88.687% capacity value for gas CTs that is equal to 29,009 MW of nameplate CT capacity. Using an installed cost of $848,500/MW,20 this represents a cost of $24.614 billion. This $24.6 billion figure represents

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20 As discussed earlier in this affidavit, this is the midpoint of the $799,000-898,000/MW range reported for PJM. [Link](http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-variable-resource-requirement-curve-study.ashx?la=en)
the high-end estimate of cost impacts from PJM’s MOPR-Ex proposal, assuming that no RPS-driven renewable resources are able to use the MOPR-Ex exemptions and are therefore barred from the capacity market.

This concludes my affidavit.
UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection LLC  )  ER18-1314-000

Verification of Michael Goggin

On Behalf of the Sustainable FERC Project, Natural Resources Defense Council, and Sierra Club

I, Michael Goggin, declare under penalty of perjury that the attached affidavit is true and correct to the best of my knowledge, information and belief.

Michael Goggin

Execution Date: May 7, 2018
Clean Energy Advocates Protest ER18 1314 - Final.PDF......................1-291
Exhibit B
Protest of Clean Energy Advocates, June 20, 2018
Docket No. EL18-169
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC, Complainants,
v. PJM Interconnection, L.L.C., Respondent.

PROTEST OF CLEAN ENERGY ADVOCATES

Pursuant to Rule 211 of the Federal Energy Regulatory Commission’s (“Commission”) Rules of Practice and Procedure, the Sustainable FERC Project, Sierra Club, and Natural Resources Defense Council (“Clean Energy Advocates”) respectfully submit this protest and comment on the Federal Power Act (“FPA” or “the Act”) section 206 complaint dated May 31, 2018 of CPV Power Holdings, L.P., Calpine Corporation, and Eastern Generation, LLC (collectively, “Complainants”) against PJM Interconnection, L.L.C. (“PJM”). Complainants request that the Commission find that current rates concerning the Reliability Pricing Model (“RPM”) administered by PJM are unjust and unreasonable, and ask that PJM be required to adopt rules expanding the scope of the Minimum Offer Price Rule (“MOPR”). However, Complainants have failed to meet their twin burden under section 206: they have neither demonstrated that the status quo is unjust and unreasonable, nor have they shown that their

1 18 C.F.R. §§ 385.211 and 214.
2 16 U.S.C. § 824e.
4 Id. at 22.
proffered alternative is itself just and reasonable. Accordingly, the Commission must reject the Complaint.

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I. **Background.**

On April 9, 2018, PJM proposed revisions to the RPM via a filing to the Commission under section 205 of the FPA.\(^5\) Specifically, PJM asserted that state policies to encourage certain classes of generating resources were having increasingly adverse effects on the RPM’s ability to attract investment in new capacity, and offered in the alternative two proposals to reform the market’s rules. PJM claims that it preferred approach, “Capacity Repricing,” would “accommodate” state-supported resources by splitting the RPM into two stages: in the first stage, resources receiving support through state policy would still be given the opportunity to clear the auction based on their actual offer price (reflecting their rights and obligations under state law); in the second stage, the clearing price paid to all resources would be determined in a second run of the algorithm in which all resources deemed to have received “actionable subsidies” have their offers administratively adjusted to remove the value of the subsidy received.\(^6\) PJM’s alternative proposal, “MOPR-Ex,” would “mitigate” state policies by extending the current MOPR to existing and new capacity resources of all types, while offering several unit-specific or categorical exemptions.\(^7\)

Clean Energy Advocates and others protested PJM’s April 9 filing.\(^8\) Clean Energy Advocates urged the Commission to reject the filing, showing that both Capacity Repricing and MOPR-Ex are unduly discriminatory and preferential, arbitrarily imposing excessive costs on some customers and not others, and harming some resources and not others without a principled basis. We further demonstrated that neither proposal is just and reasonable because both are based on arbitrary line-drawing, would saddle

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5 Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the Capacity Market, Docket No. ER18-1314, PJM Interconnection, L.L.C. (Apr. 9, 2018) (‘Jump Ball filing’).
6 *Id.* at 59-60.
7 *Id.* at 98-99.
8 Protest of Clean Energy Advocates, Docket No. ER18-1314 (May 7, 2018) (“Jump Ball filing protest”). The Jump Ball filing protest is attached hereto in its entirety, as Attachment A.
consumers with billions in extra costs without providing any resource adequacy or other benefits, and would increase market uncertainty. PJM’s proposals are currently under consideration at the Commission.9

Complainants now offer for the Commission’s consideration of a third proposal. Complainants echo PJM’s assertions that “Commission action is needed now,” arguing that the participation of resources supported by state policies in the RPM leads to severe price suppression, posing a “[s]erious [a]nd [i]mminent [t]hreat” to the market.10 However, in Complainants’ view, PJM’s proposals do not go far enough, and an even more extreme expansion of the MOPR “[i]s [r]equired [t]o [e]ffectively [a]ddress [t]he [p]ernicious [i]mpacts [o]f [s]ubsidy [p]rograms.”11 Specifically, this Extreme MOPR “would be MOPR-Ex with the Unit-Specific Exception but without the Self-Supply, Competitive, Public Entity and RPS Exemptions.”12 Complainants thus argue that “the currently effective MOPR is unjust and unreasonable, because it permits artificial price suppression by resources that are receiving out-of-market subsidies,” and urge the Commission to require PJM to adopt the Extreme MOPR as a just and reasonable alternative.13

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9 PJM also suggested that a third option, altering the terms of the MOPR-Ex to remove the Renewable Portfolio Standards (“RPS”) exemption, might be available for consideration by the Commission. Jump Ball filing at 114. But, as the current Complaint concedes, that proposal is not properly before the Commission. Complaint at 9-10.

10 Complaint at 10.

11 Complaint at 18. Although Complainants dub their proposal the “Clean MOPR,” this protest refers to Complainants’ proposal as the “Extreme MOPR.”

12 Id. at 22-24. Complainants also assert that “unmitigated participation of subsidized resources will inevitably undermine grid resilience.” Id. at 16-17. The definition of resilience and actions to ensure it are under active consideration in Docket No. AD18-7. Indefinite “resilience” concerns do not provide a reasoned basis to assess whether rates are just and reasonable, nor do they justify interventions into the market.
I. Argument.

Under FPA section 206, Complainants bear the burden of demonstrating that existing rates are “unjust, unreasonable, unduly discriminatory or preferential.” 14 Complainants have failed to meet this burden. Moreover, the Extreme MOPR is not just and reasonable; indeed, it suffers from the same fundamental defects that make MOPR-Ex unjust and unreasonable. Indeed, under Extreme MOPR the harmful effects to customers, other market participants, and market certainty are far worse.

A. Complainants Have Failed to Demonstrate that the Status Quo is Unjust and Unreasonable.

Echoing PJM, Complainants assert that “Commission action is needed now” to address the supposed pernicious effects of state-supported resources’ participation in the RPM. 15 But there is simply no evidence that investment in PJM is lacking, reliability is threatened, that the impacts of state policies on the wholesale market now are larger than ever before, or that the programs targeted have any different or more harmful impacts than policies that have long affected the markets. Indeed, state policy preferences have always affected market prices, and RPM prices should reflect this reality. As scholars at the Institute for Policy Integrity summed up their own assessment of PJM’s proposal, “[t]here is no credible evidence that externality payments [the policies targeted by PJM] threaten the viability of markets.” 16 Complainants have plainly failed to demonstrate that the status quo is unjust and unreasonable.

14 16 U.S.C. § 824e; see also FirstEnergy Serv. Co. v. FERC, 758 F.3d 346, 353 (D.C. Cir. 2014) (“Under section 206, ‘the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon . . . the complainant.’”) (quoting Sithe/Independence Power Partners, L.P. v. FERC, 165 F.3d 944, 948 (D.C. Cir. 1999)).

15 Complaint at 10.

1. PJM faces no conceivable threat to reliability.

Complainants assert that “the effects of below-cost offers from subsidized resources on prices in the RPM Auctions will be nothing short of devastating.”\textsuperscript{17} However, Complainants could not conceivably substantiate a claim that PJM’s market faces any foreseeable threat to the RPM’s core function, ensuring resource adequacy, and do not try to do so. Objective standards of the market’s performance simply would not support such an assertion. The idea that market prices are too low to support new entry is defied by the tremendous amount of new build entering PJM in spite of already high reserve margins.

PJM's latest planning reserve margin for the summer of 2018 is 28.7 percent.\textsuperscript{18} This is significantly higher than PJM Staff’s recommended installed reserve margin target of between 15.8 and 16.1 for delivery years 2018/2019 through 2021/2022.\textsuperscript{19}

Further, when looking forward at expected power builds and retirements, there appears to be no risk of a capacity shortfall in the next few years. As shown in Figure 1, there are over 20 GW of new natural gas capacity under construction or in advanced development expected to enter operation by the end of 2021. An additional 18 GW of natural gas capacity has been announced or is in early development. At the same time, only 7.4 GW of fossil and nuclear capacity have announced and approved retirement dates between now and 2021, according to S&P Global Market Intelligence.\textsuperscript{20} By 2021, PJM could see a

\textsuperscript{17} Complaint at 13.
\textsuperscript{19} PJM, \textit{2017 PJM Reserve Requirement Study} 8 (Oct. 12, 2017), \url{http://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx}.
\textsuperscript{20} S&P Market Intelligence did not include FES’ most recent announcements around Davis-Besse, Perry, and Beaver Valley in their list of announced retirements due to the status of deactivation materials and approval as of April 20, 2018. S&P Global Market Intelligence, Power Plants Database and Screener Tool, \textit{Subscription required}, \url{https://www.spglobal.com/marketintelligence/en/} (Accessed May 3, 2018).
net addition of up to 40 GW, even as load is expected to see relatively little growth over the same timeframe.  

Figure 1: New Capacity in PJM (MW)

<table>
<thead>
<tr>
<th>New Capacity in PJM (MW)*</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023 NA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>11,444.7</td>
<td>1,182.0</td>
<td>6,323.4</td>
<td>2,662.0</td>
<td>43.2</td>
<td></td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>2,025.4</td>
<td>2,359.0</td>
<td>6,224.8</td>
<td>7,418.5</td>
<td>2,059.2</td>
<td></td>
</tr>
<tr>
<td>Renewables</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>1,164.1</td>
<td>545.3</td>
<td>73.7</td>
<td>10.9</td>
<td>34.0</td>
<td>220.2</td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>1,301.7</td>
<td>3,180.8</td>
<td>2,413.7</td>
<td>-</td>
<td>1,006.0</td>
<td>50.0</td>
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<tr>
<td>Other</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>60.0</td>
<td>135.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>114.1</td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>11.6</td>
<td>11.6</td>
<td>0.8</td>
<td>-</td>
<td>-</td>
<td>1,754.1</td>
</tr>
<tr>
<td>Total Capacity Announced or In Development</td>
<td>16,007.6</td>
<td>7,413.7</td>
<td>14,036.4</td>
<td>10,080.5</td>
<td>1,016.9</td>
<td>84.0</td>
</tr>
<tr>
<td>Announced Retirements</td>
<td>5,587.1</td>
<td>1,707.6</td>
<td>118.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Cumulative Net Capacity Change (High) | 10,420.5 | 16,126.8 | 30,045.0 | 40,125.5 | 41,142.3 | 41,226.3 |
Cumulative Net Capacity Change (Low) | 7,081.7 | 7,236.4 | 12,515.5 | 15,177.5 | 15,188.4 | 15,222.4 |

Source: S&P Global Market Intelligence. * When a unit development is announced, all units listed are considered; some additional public announcement or permit application will be taken to initiate coverage. A project is updated to early development when the permitting process begins. A project is approved or contract signed to the project. A project is updated to construction when a new unit begins; site preparations are not under construction.

There is no evidence at all to suggest the investor appetite in the PJM region is on the wane. A recent, informal poll at the Platt Global Power Markets Conference found that a large plurality (45 percent) of respondents “think that PJM is the best place where investors are likely to earn a targeted rate of return on new generation.” This was more than double the next highest polling region (20 percent). As PJM itself stated in the Resource Investment Whitepaper cited in its filing, “Given the level of capital being...

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23 Id.
attracted to PJM, it seems highly implausible to claim the market is not compensating merchant investors enough for risks they assume.”

PJM’s markets have succeeded at attracting substantial investment at the same time PJM member states have pursued their own policies to incentivize certain types of generation. Indeed, PJM has successfully run a “hybrid” market for decades without any reliability crisis. PJM became the first fully-functioning U.S. independent system operator and then regional transmission organization in 1997 and 2002, respectively. By that time, member utilities in New Jersey were already complying with state policies including renewable or alternative energy standards and energy efficiency resource standards. As additional utility territories were added into PJM’s footprint over the next three years, Delaware, Pennsylvania, Maryland, and the District of Columbia also implemented new state policies supporting the development of renewable and other resources. By the end of the decade, 10 states within the PJM territory had adopted state policies promoting and/or mandating renewable energy technology adoption and energy efficiency savings levels. Three states were also members of a regional carbon market.

As shown in Figure 2 below, despite this concurrent growth of PJM’s footprint and state energy policies since the early 2000s, the region was routinely able to attract new capacity under both the current RPM design and earlier market structures.

27 PJM History, *supra* n.25.
28 See Jump Ball filing protest, Attachment A.
29 *Id.*
There is also little evidence that state policies supporting renewable energy development have had or are having a measurable impact on market prices or investor confidence. The largest source of new builds, both historically and the near-term future, are natural gas facilities. As shown in Figure 3, around 95 percent of all projects identified by S&P Global Market Intelligence as under construction or in advanced development within the PJM footprint are natural gas projects. Just five percent are wind and solar energy. Even when accounting for all stages of development, wind and solar projects represent just a quarter of all projects in S&P’s tracking database.

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Stakeholder support for the current RPM construct, including the current MOPR, evinces widespread confidence in the continued ability of PJM’s capacity market to work alongside state policies. PJM’s stakeholder engagement process prior to its April 9, 2018 filing revealed that the maintenance of the status quo in the RPM has greater support among stakeholders than any proposed reforms. In a November 2017 straw poll of members of the Capacity Construct/Public Policy Senior Task Force (“CCPPSTF”), the proposal that received the most support from participating stakeholders (64 percent in favor) was to retain the status quo and not file any tariff revisions with the Commission.32

Complainants assert that “the currently effective MOPR is manifestly unjust and unreasonable because it fails adequately to mitigate artificial suppression of RPM clearing prices by subsidized resources.”33 This claim is belied by the fact that the RPM continues to secure ample capacity reserves and maintain a high level of investor confidence under current market rules. Complainants have failed to demonstrate that the current MOPR is unjust and unreasonable.

32 PJM, CCPPSTF Vote Results at 5 (Nov. 21, 2017), http://pjm.com/-/media/committees-groups/task-forces/ccppstf/20171121/20171121-ccppstf-vote-results.ashx. Because PJM did not allow the status quo to be considered as a binding option, an alternate option receiving the next highest level of support was advanced (a version that would become the pending MOPR-Ex proposal).

33 Complaint at 10.
2. Complainants have not shown that the RPM’s inclusion of state-supported resources makes the current MOPR unjust and unreasonable.

Complainants assert that the Extreme MOPR is “particularly appropriate” for PJM and consonant with past modifications to the PJM MOPR.\(^\text{34}\) This is not true. In targeting renewable resources that do not present a risk of the exercise of monopsony power, the Extreme MOPR would represent an unprecedented expansion of the rule. Past MOPR modifications do not support Complainant’s claim that allowing state-supported renewable resources to participate in the RPM makes the current MOPR unjust and unreasonable.

Several principles have remained constant since the PJM MOPR was first introduced in 2006. As the Commission described to the D.C. Circuit in a case defending its rejection of several proposal changes to the MOPR, the rule was designed with a purpose “to prevent the exercise of monopsony power—that is, price suppression by utilities that offer capacity into the market but buy more capacity than they sell.”\(^\text{35}\) The goal is to “prevent market manipulation,” and thus “[MOPR] is designed to identify new resources with the incentive and ability to depress auction clearing prices.”\(^\text{36}\) Further, the Commission has always balanced the need for mitigation of buyer-side market power against the “risk of over-mitigation.”\(^\text{37}\) Accordingly, the current MOPR does not apply to categories of resources that are not considered to present the threat of price suppression including nuclear, coal, hydroelectric, integrated gasification combined cycle plants, wind, and solar.\(^\text{38}\)

\(^{34}\) Complaint at 21.
\(^{35}\) Brief of Respondent, FERC, *NRG Power Marketing, LLC v. FERC*, D.C. Cir. Case Nos. 15-1452, 15-1454 (Sept. 27, 2016), 2016 WL 5405117 at *11, *12; *see also id.* at *40 (exemptions upheld were designed to sort out resources that lack incentives to bid their actual costs).
\(^{36}\) *Id.* at *12.
\(^{37}\) *Id.* at *21.
PJM and the Commission have agreed that wind and solar resources are poorly suited to the exercise of buyer-side market power. In adopting the MOPR exemption for wind and solar resources, the Commission found persuasive PJM’s explanation that, compared to combustion turbine or combined cycle gas plants, “wind and solar resources are a poor choice if a developer’s primary purpose is to suppress capacity market prices.” An entity seeking to exercise buyer market power would need to offer as much as eight times the nameplate capacity of a competing gas plant to achieve the same price benefit. In addition, the Commission agreed that the long-lead time for development of wind and solar resources provided good reason to exempt them from the MOPR. Developers of such projects would make decisions based on “several years of auctions and energy market prices” and would necessarily begin construction and incur costs years in advance of the first auction it could participate in. By the time such a resource participates in the Base Residual Auction (“BRA”), “the resource would most likely have tens or hundreds of millions of dollars of sunk costs” resulting in a small or even zero net avoidable incremental cost.

To date, because PJM’s MOPR has been narrowly focused on resources that would have both the “incentive and ability” to benefit from exercising buyer market power, the Commission has not had to address the appropriateness of targeting such a large share of capacity in PJM that are being built (or were built, in the case of existing resources to which the Extreme MOPR would apply) for reasons other than the potential to financially gain by making an artificially low offer – an issue now presented in this proceeding. Complainants have failed to show that allowing state-supported renewable resources to participate in the RPM makes the current MOPR unjust and unreasonable.

39 Id. at P 153.
40 Id.
41 Id. at P 155.
42 Id.
43 Id.
3. **Policy preferences have always affected market prices.**

Echoing the Independent Market Monitor (“IMM”), Complainants argue that “[t]he subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.”\(^{44}\) Complainants suggest that recent expansions in state programs supporting renewable and nuclear resources are “contagious” subsidies that will “fundamentally undermine the RPM market.”\(^{45}\) Yet they offer no evidence that the policy actions cited are, by any measure, more impactful or concerning than the pervasive policy choices by governments at all levels that have affected PJM market prices throughout its history.

Historical data demonstrates that government policies have provided substantial support targeted toward specific types of capacity resources, including large-scale ones that comprise a significant share of capacity in the PJM market. There is no reason to believe that historic policy actions would have any less impact on market prices than Complainants contend they do today. In 1989 alone, for example, coal-fired generators benefited from nearly seven and a half billion dollars in federal government support, and natural gas-fired generators a little less than one billion.\(^{46}\) On average, federal subsidies to conventional generation\(^{47}\) amounted to roughly eleven percent of the cost of electricity to an end-consumer.\(^{48}\) It defies reason to suggest that support of this magnitude did not affect the composition of capacity resources, providing advantages to some resources and not others, and affecting wholesale prices. Indeed, subsidy expert Douglas Koplow concludes that historic subsidies that have underwritten long-lived capital

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\(^{44}\) Complaint at 15.

\(^{45}\) Id. at 14.


\(^{47}\) Including nuclear, hydro, coal, gas, and oil.

investments would have “the same type of market effect as current subsidies.” The same basic principle would apply, “regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted.” And while renewables are “late entrants” to the scene, incumbent generators have received many large state tax breaks that are documented as far back as the 1950s, 60s, and 70s. For the RPM to attempt to “mitigate” contemporary state programs supporting renewable energy would be an arbitrary and ill-advised overreach in light of this history.

4. **PJM capacity market offers and prices should reflect revenues earned pursuant to state policies.**

Like PJM, Complainants make much of supposed problems stemming from state programs that compensate generators for environmental benefits when in fact no such problems exist. State renewable energy policies are fully consistent with the continued functioning of the RPM as a competitive market. Efficient market rules would allow state-sponsored resources to make economically rational capacity market offers based on the revenues they earn pursuant to state policies. Allowing this behavior is the competitive approach because it honors the rights and obligations created pursuant to state law. While treating state property rights like any other legal obligations would be the correct approach even were the Commission the nation’s sole energy regulator, the Federal Power Act’s “collaborative federalism”

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50 *Id.* at 4.
51 *Id.* at 17. Federal tax breaks for conventional energy go back even earlier in the history of the energy sector.
52 See *Wheelabrator Lisbon, Inc. v. Conn. Dep’t of Pub. Util. Control*, 531 F.3d 183, 186 (2d Cir. 2008) (“RECs are inventions of state property law”); see also, e.g., Protest by the Connecticut Public Utilities Regulatory Authority et al., Docket No. ER18-619, *ISO New England, Inc.*, Affidavit of Cliff W. Hamal, at P 27 (Jan. 29, 2018) (“Offering capacity at a zero price . . . represents the rational competitive response of a new resource that has taken on a commitment to meet the requirements of a state policy.”).
approach that “envisions a federal-state relationship marked by interdependence” further strengthens the logic behind doing so.

As Robert Gramlich, a former PJM economist and adviser to Chairman Pat Wood III, explains, the Commission’s general practice since the inception of PJM’s markets has been to allow revenues and costs stemming from public policies to affect offer prices. The Commission’s role is to regulate for just and reasonable rates when accounting for exogenous market inputs, not in spite of them. In a past order addressing PJM’s capacity market rules, for instance, the Commission explicitly directed PJM to provide for the costs of state environmental regulations to be reflected in capacity market offer prices. Similarly, NYISO’s tariff includes within going-forward costs “the costs . . . necessary to comply with federal or state environmental . . . requirements that must be met in order to supply Installed Capacity.”

The fact that the state laws at issue in this case create revenues rather than costs does not make those economic consequences any less real. As the Commission explained in the context of demand response resources, offers from resources that also earned revenue under state retail demand response programs did not present a risk of “artificial price suppression.” Among the many reasons such a risk

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53 Hughes, 136 S. Ct. 1288, 1300 (Sotomayor, J., concurring).
54 Affidavit of Robert Gramlich, Grid Strategies LLC, On Behalf of Sustainable FERC Project, Natural Resources Defense Council and Sierra Club, at Section V (May 7, 2018) (attached to Jump Ball filing protest as Appendix B) (“Gramlich Affidavit”).
55 See id.
56 As PJM explains, where a state regulation limits a unit’s run time, that creates an opportunity cost because operation in any given hour may entail “giving up revenue that it could earn if it was running at a more profitable time of the year.” PJM Interconnection, L.L.C., A Review of Generation Compensation and Cost Elements in the PJM Markets, at 15 (2009), https://perma.cc/BMV7-5QNL. Faulting PJM for not “clearly and explicitly provid[ing] for the inclusion of opportunity costs, especially for energy and environmentally-limited resources” (resources whose run time is limited by state or federal environmental regulations) in resources’ default bids, the Commission ordered PJM to revise its mitigation rules to do so. PJM Interconnection, L.L.C., 126 FERC ¶ 61,145 at P 42 (Feb. 19, 2009).
57 NYISO Market Administration and Control Services Tariff; Attachment H, § 23.2.1. New York State Pub. Serv. Comm’n et al., 158 FERC ¶ 61,137 at P 33 (Feb. 3, 2017); see also PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at P 106 (Dec. 22, 2006) (default bids under
was not present was that such state program revenues “are actually for providing services that are separate
and distinct from the payments that [such demand response resources] receive for participating in
NYISO’s ICAP market.” In other words, it is perfectly legitimate for revenue streams from sales of
state-defined products to be reflected in offer prices, not a sign of “artificial” suppression.

The mere fact that state programs affect wholesale market outcomes does not mean that they are
market distorting. Such logic would empower the Commission to undo the wholesale market effects of
any state law of any kind. The RPM should allow resources that earn revenues from state policies
supporting renewable energy to fully participate in the market, both in recognition that such policies like
any other government action that affects a resources’ offer price, and out of respect for states’ role in our
cooperative federalist system.

B. The Extreme MOPR Proposal is Not Just and Reasonable.

Complainants’ alternative, the Extreme MOPR, is plagued by the same defects as PJM’s proposed
MOPR-Ex. As a threshold matter, Complainants misinterpret the FPA, articulating a legally incorrect test
of “just and reasonable.” The Extreme MOPR would have grievous practical impacts on consumers and
capacity market participants as well: it would lead to undue discrimination, force customers to buy more

MOPR should allow for recovery of investment costs to meet mandated environmental
requirements); PJM Interconnection, L.L.C., 119 FERC ¶ 61,318 at P 150 (June 25, 2007)
(customer is not to be shielded from costs of supply to comply with environmental mandates).
New York State Pub. Serv. Comm’n et al., 158 FERC ¶ 61,137 at P 33.

59 Consistent with the principle that such revenues should be included in NYISO’s assessment of
unit costs, the NYISO market monitor does include revenues from sales of credits compensating
environmental benefits in calculating whether a unit should be exempted under Part B of the
mitigation exemption test. See New York Pub. Serv. Comm’n et al., 153 FERC ¶ 61,022 at P 48
(Oct. 9, 2015) (for renewable resources that are not otherwise exempt from buyer-side mitigation
rules, Part B of the mitigation exemption test “takes into account certain incentives for owning
renewable resources by reducing the unit-specific Net CONE”).

50 See FERC v. Electric Power Supply Association, 136 S. Ct. 760, 774 (2016) (holding that
FERC’s jurisdiction is limited to rules or practice that “directly affect” wholesale rates). Even if
the market rules only targeted state laws with large effects on wholesale market outcomes, that
would sweep in a wide array of state laws that are well-understood to be beyond the
Commission’s reach, such as siting requirements, tax codes, and pollution control laws.
capacity than necessary, shift regulatory risk from generators to consumers, undermine legitimate state policies, and set the RPM on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed. Accordingly, even if the Commission were to agree with Complainants that the current PJM MOPR is unjust and unreasonable, the Extreme MOPR would not represent a viable alternative because it is itself unjust and unreasonable.

1. **Extreme MOPR is not just and reasonable because Complainants rely on the wrong legal standard and thereby fail to provide the record necessary to approve the proposal.**

    As a threshold legal flaw, Complainants cannot demonstrate that their Extreme MOPR proposal is just and reasonable because they rely on a standard that lacks a basis in longstanding Commission precedent and that would leave consumers without statutory protection. By focusing on the wrong, investor-focused standard, Complainants fail to address how their proposal will impact wholesale customers and thereby deny the Commission the record it requires to evaluate whether the approach is just and reasonable.

    Complainants point to the Commission’s recent novel articulation of the “first principles” of the capacity markets in its recent order approving ISO New England’s new capacity market construct.62 They argue that the RPM cannot continue to advance these so-called “first principles” in the face of state policy actions.63 Like PJM, Complainants make achievement of these new principles the core benchmark for approval of their proposal, structuring their argument and evidence against that standard.64 Fatally, however, much like the Commission’s reliance on these principles in the CASPR Order, Complainants boil these principles down to a test of investor expectations.

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63 Complaint at 14.

64 See, e.g., id. at 20 (arguing that the Extreme MOPR would satisfy each of the CASPR Order’s “first principles”).
The Commission cannot so neglect its “primary aim” to protect consumers “from excessive rates and charges.”\textsuperscript{65} Such “protection of the public interest” must be clearly “distinguished from the private interests of the utilities.”\textsuperscript{66} Evidence of a voracious appetite to invest in the market is not an adequate safeguard of consumer interests— one need only consider the latest Wall Street financial meltdown to recognize this truth—and the Commission has never held as such.\textsuperscript{67} Nor can examining a single factor, whether investment in merchant generation will thrive under a capacity construct, sufficiently account for the consumer impacts of a proposed market construct. The Commission’s long-standing interpretation of the FPA entails consideration of the inherent trade-offs across consumer and supply interests in determining whether a rate is just and reasonable, and does not permit such shortcuts.\textsuperscript{68} In fact, the

\textsuperscript{65} \textit{Fed. Power Comm’n v. Sierra Pac. Power Co.}, 350 U.S. 348, 355 (1956) (“That the purpose of the power given the Commission by [section] 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities, is evidenced by the recital in [section] 201 of the Act that the scheme of regulation imposed ‘is necessary the public interest.’”); \textit{Pa. Water & Power Co. v. Fed. Power Comm’n}, 343 U.S. 414, 418 (1952) (“A major purpose of the whole Act is to protect power consumers against excessive prices.”); \textit{Xcel Energy Servs. Inc. v. FERC}, 815 F.3d 947, 952 (D.C. Cir. 2016) (“It is long-established that ‘the primary aim [of the FPA] is the protection of consumers from excessive rates and charges.’” (quoting \textit{Mun. Light Bds. of Reading & Wakefield v. FPC}, 450 F.2d 1341, 1348 (D.C. Cir. 1971)); \textit{Jersey Cent. Power & Light Co. v. FERC}, 810 F.2d 1168, 1177 (D.C. Cir. 1987) (“[F]rom the earliest cases, the end of public utility regulation has been recognized to be protection of consumers from exorbitant rates.”).


\textsuperscript{67} Of course, whether prices provide adequate signals to invest in new capacity when such capacity is needed is an important factor in the Commission’s balancing test. It has never, however, been an exclusive factor that overrides the need to consider other factors and their impacts on consumer and supply interests.

\textsuperscript{68} \textit{Fed. Power Comm’n v. Hope Natural Gas Co.}, 320 U.S. 591, 603 (1944); \textit{New England Power Generators Ass’n, Inc.}, 146 FERC ¶ 61,039 at P 52 (Jan. 24, 2014) (“[I]t has long been established that ‘the fixing of “just and reasonable” rates, involves a balancing of the investor and consumer interests’”). \textit{Promoting Transmission Investment through Pricing Reform}, 116 FERC ¶ 61,057 at P 21 (July 20, 2006), reh’g granted in part by 117 FERC ¶ 61,345 (Dec. 22, 2006), decision clarified on denial of reh’g by 119 FERC ¶ 61,062 (Apr. 19, 2007) (“The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests. It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our polices must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives.”);
Extreme MOPR proposal represents a classic case where confidence for investors in supply resources will not translate into customer benefits. As further explained in section II.B.3, the Extreme MOPR benefits suppliers at the expense of customers by channeling customer dollars toward unnecessary, redundant capacity. In simply assuming that what is good for suppliers is good for customers, Complainants have failed to put forward the record necessary for the Commission to conduct its vital task of balancing consumer and supplier interests.

2. The Extreme MOPR would result in arbitrary discrimination against customers and sellers.

Although Complainants describe their proposal as “very straight-forward, easily understood and, with the elimination of the exceptions and exemptions, administratively simpler than MOPR-Ex,” that is not the case. The Extreme MOPR would result in arbitrary discrimination against both buyers and sellers and run into many of the same administrability problems as MOPR-Ex because it adopts the same arbitrary definition of “material subsidy” put forward by PJM, and excludes policies that undeniably would have the same effect on market participant behavior and investor expectations.

a. The Extreme MOPR arbitrarily exempts general economic development and local siting incentives.

Like PJM, Complainants would define “Material Subsidy” to incentives (1) that utilize criteria designed to incent or promote general industrial development in an area and (2) from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality from its definition of actionable subsidies. There is no basis to conclude that such programs do not provide large-scale support that is narrowly

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69 Complaint at 18 (quoting Complaint, Attachment A, Affidavit of Roy J. Shanker, Ph.D., ¶ 39) (internal quotation marks omitted).
70 Complaint, Attachment A, Affidavit of Roy J. Shanker, Ph.D. at 4 n.1.
targeted to specific energy assets, simply because they support development within a particular area or siting within a particular locality.\footnote{Koplow report at 5-9.}

Indeed, as Koplow describes, “these large subsidies to individual facilities would affect power market structure no differently than an energy-related grant of similar size or a targeted tax break.”\footnote{Id. at 6.} Koplow’s research provides only a sample of the kinds of programs likely to fall within this exemption, yet even that time-constrained review reveals numerous targeted subsidies to energy-related activities that exceed $20 million.\footnote{Id. at 29, Table A-1.} Some economic development programs work to the direct benefit of single resources, as is the case for the Pennsylvania Keystone Opportunity Zone, home to the Panda Power Hummel Power Station. That over 1,100 MW gas plant received state and local tax abatement to support its development, after receiving local officials’ approval under the development program.\footnote{See FocusCentralPA Sunbury Generation Site Report (last visited May 2, 2018), \url{http://focuscentralpa.org/project-breakout/projectbreakout_sitesurveyinputsheetsunburygeneration/} (“In order to receive the KOZ designation for the site, Sunbury needed to receive local and state government approval.”). Because Pennsylvania does not track the costs of the program in terms of lost tax revenues, it is difficult to quantify the precise benefit accruing to individual resources during the time allowed by the extremely constrained comment period. \url{http://lbfc.legis.state.pa.us/Resources/Documents/Reports/316.pdf}.} Moreover, the very large billion-dollar economic development projects that directly support up- or down-stream energy sector activities can often hide cross-subsidization that benefits generation located nearby.\footnote{See Koplow report at 8.} From more than a billion dollars in subsidies to local plants to support in-state demand for coal (and hence, cheaper coal generation) in Kentucky, to more than a billion and a half dollars in subsidy for natural gas development infrastructure in the Marcellus Shale in Pennsylvania (with corresponding benefits to cheap gas for regional gas generators) and a massive proposed natural gas hub laden with multi-billion dollars...
in foreign national and U.S. federal subsidy in the works for West Virginia, it is hard to pretend that ignoring these economic development programs ensures a level playing field for all resources—including fuel-free resources like renewables—in the competitive markets.

Nor can one discount the direct link between these kind of economic development incentives and the decisions of market participants to enter or exit the market. First, states are explicitly aiming to change market participant’s behavior through these programs. For example, in 2015, West Virginia commissioned a 55-page study to identify tax incentives that would “ultimately boost coal production in West Virginia by incentivizing the state’s utilities and manufacturers to use West Virginia coal.” There can be little doubt other states are taking similarly explicit steps to protect their preferred resources. Second, research finds a strong correlation between plant closures and the availability of these benefits intended to promote local economic development. For example, a generator that is in a state with an in-state coal mine (which are also the states that support coal as a local economic development benefit) is seven percent less likely to have closed by 2014 than a coal power plant without such in-state fuel inputs. In concluding that state RPS programs must be subject to mitigation in order to protect the competitive markets, Complaints assert that “out-of-market subsidies in any . . . contexts are bad; they distort prices, and interfere with the efficient

See id. at 6-9.

Bowen et al., Government Incentives to Promote Demand for West Virginia Coal, West Virginia University, Bureau of Business and Economic Research (2015) at 1, 24 (“West Virginia and neighboring states have various policies in place to incentivize the consumption of locally produced coal. Many of these policies act by lowering production costs for coal mines, allowing them to reduce the price they charge for coal and thus providing incentives for utilities and other buyers to switch suppliers to locally produced coal.”), http://busecon.wvu.edu/bber/pdfs/BBER-2015-01.pdf.

entry and exit of generation.” 79 Under a consistent approach, the Extreme MOPR could not categorically exempt economic development and local siting programs, which are undoubtedly out-of-market subsidies of the sort that Complainants claim pose a dire threat to the RPM.

b. The Extreme MOPR arbitrarily ignores “material” support to conventional generators.

The definition of “Material Subsidy” is also arbitrary because of its scope, which extends to any form of support to a resource that exceeds one percent of its projected annual revenues from PJM markets. 80 This definition is arbitrary. It is not at all clear, for example, that support that is a little less than one percent of the revenue of each resource would not affect offer behavior, but support that is a little more than one percent of revenue will. Or, accordingly, that the former (just under one percent) will not affect market outcomes, but the latter (just over one percent) will. This is particularly true if one imagines that the first program benefits tens of thousands of megawatts at a cumulative value of billions of dollars, but the second affects only a few thousand megawatts and at a much lower total dollar value. A subsidy of just under one percent of a 1,000 MW resource’s offer price, for instance, is nearly 50 times greater in magnitude than a subsidy of just over one percent a 20 MW resource. If either resource would have cleared in the capacity market with the subsidy but fails to clear without, the subsidy for the larger resource—even if smaller when measured as a proportion of the resource it applies to—would have far greater market impact than the subsidy representing a higher proportion of a smaller resource’s revenues. This focus on relative value of support to the resource (rather than impact to the market) systematically favors larger resources, who are able to receive subsidies far larger in magnitude than those received by smaller resources without being mitigated.

79 Complaint at 13 (quoting Complaint, Attachment A, Affidavit of Roy J. Shanker, Ph.D, ¶ 10) (internal quotation marks omitted).
80 Jump Ball filing at 74 (citing proposed PJM Tariff, Attachment DD § 5.14(j)(2)(d) (Option A)).
Further, PJM’s own testimony contradicts the notion that the size of a subsidy is determinative of whether an offer from a resource materially affects the market. As Mr. Giacomoni, PJM’s declarant, describes, “the size of the subsidy does not, by itself dictate whether a resource would be economic in PJM’s market . . . [d]epending on the resource’s costs, and the revenue the resource receives in the PJM energy and ancillary service markets, the subsidy payments could effectively be surplus.”\(^{81}\) In other words, PJM’s revenue threshold, adopted by Complainants, will capture and reprice resources that are economic and whose offers, even by PJM’s judgment, are therefore not price-suppressive. Moreover, scholars from the Institute for Policy Integrity make clear, simply affecting an offer does not necessarily equate to an effect on clearing prices:

Any decrease in the bid of an infra-marginal unit that would have cleared the auction anyway, all else equal, would not affect the market clearing price. Thus, externality payments can affect the auction price only in limited situations: (1) when they induce entry (or prevent exit), increasing available supply of capacity, and hence lowering the market clearing price; or (2) when they directly lower the marginal bid, and hence the market clearing price.\(^{82}\)

Thus, like MOPR-Ex, the Extreme MOPR does not effectively target price-suppression as Complainants claim.

Second, as subsidy expert Doug Koplow explains in his report attached to Clean Energy Advocates’ protest of PJM’s proposals, “the most important subsidy mechanisms can vary widely by energy type,” and include subsidies not encompassed by MOPR-Ex (and by extension, the Extreme MOPR).\(^{83}\) “Policies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions.”\(^{84}\) Koplow identified billions of dollars in state support to conventional generators that would appear to have the same effects on

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\(^{81}\) Jump Ball filing, Attachment F, Affidavit of Dr. Anthony Giacomoni on Behalf of PJM Interconnection L.L.C., ¶ 36.

\(^{82}\) IPI report at 15.

\(^{83}\) Koplow report at 2.

\(^{84}\) Id. at 10.
behavior offer and, per PJM’s theory, market outcomes as those targeted by PJM.\textsuperscript{85} For example, a $1.1 billion package of support to five coal-to-liquids plants in Kentucky would keep prices for coal artificially low for coal-generators in the region (including the many in-state coal resources), while a $500 million dollar tax incentive for sales and use of coal further lowers the fuel costs to generators in that state.\textsuperscript{86} Coal generators relying on Kentucky coal reap additional benefits from Kentucky’s lax bonding and reclamation laws for coal mines, which artificially reduce operating costs for the affected mines.\textsuperscript{87} The dollar value of these unfunded clean-up and reclamation costs, which would otherwise fall upon coal mine operators and the cost of coal, reaches close to half a billion dollars in Kentucky.\textsuperscript{88} Moreover, unlike solar and wind—which contribute less than one percent of installed capacity in PJM’s capacity market—coal generation remains more than a third of installed capacity. Thus, even if only a small percentage of the affected generators changed their retirement decisions or adjusted their offers as a result of the Kentucky coal policies, the potential for market impact appears much larger than that of the RPS policies affected by the Extreme MOPR.

Complainants distinguish the Extreme MOPR from MOPR-Ex by proposing that “the Commission require PJM to modify the definition of ‘Material Subsidy’ to cover not only material state subsidies but also material federal subsidies or other support granted after the date of this Complaint.”\textsuperscript{89} While this change reflects the fact that federal policies as well as state policies may affect market participant behavior and investment expectations, it does not cure the fundamental arbitrariness of the Extreme MOPR, which

\begin{flushright}
\textsuperscript{85} See id. at 15-25. \\
\textsuperscript{86} Id. at 7, 16. Artificially low fuel prices would affect a resource’s ability to lower its offer in the RPM, because offers in the capacity market reflect net revenues from the energy market. To the extent the generator is recouping more than it would have otherwise through energy market revenues because of the state program, the generator will offer at a lower level (in Complainants’ terms, “artificially” lower) in the capacity market. \\
\textsuperscript{87} Id. at 24. \\
\textsuperscript{88} Id. at 25. \\
\textsuperscript{89} Complaint at 19.
\end{flushright}
would still not address other highly significant policies that can affect a capacity resource’s offer price, such as tax incentives or lax bonding and reclamation laws for coal producers.

3. The Extreme MOPR would force customers to buy more capacity than needed to provide resource adequacy in PJM.

By design, the Extreme MOPR would require customers to procure more capacity than necessary to meet the region’s reliability needs. The Extreme MOPR would operate in essentially the same manner as MOPR-Ex: by adjusting the market offers of resources supported by so-called “Material Subsidies” upward to an administratively determined minimum offer that excludes the resource’s revenues from the applicable state program.\(^90\) This will result in the “disqualifying of state-subsidized resources . . . from clearing as capacity, and will clear other resources to meet capacity needs.”\(^91\) But because the bulk of state policies affected by the Extreme MOPR have been adopted to address the urgent threat of climate change and to reduce dangerous pollution that kills states’ citizens, leads to serious health problems, and harms quality of life, states are likely to press ahead with their policies whether or not the affected resources clear in PJM’s capacity market, providing additional support to resources if necessary. In PJM’s words, “consistent with the state’s intent, the subsidized resources will likely remain in service and continue operating in the PJM Region.”\(^92\) In such cases, as PJM explains, “loads will be paying for more resources than it [sic] needs.”\(^93\)

In addition to harming customers by forcing them to pay more for capacity than necessary, the Extreme MOPR would also harm the integrity of PJM’s markets. PJM candidly acknowledged the potential for MOPR-Ex to do so, and what is true of MOPR-Ex is even more true for its more extreme variant: the requirement for customers to procure an amount of capacity well above the region’s installed

\(^{90}\) Complaint at 18-19.
\(^{91}\) Jump Ball filing at 56 (emphasis in original).
\(^{92}\) Id.
\(^{93}\) Id. (emphasis added).
reserve margin will “enable[] price suppression in the wholesale energy and ancillary services markets.”

“[G]reater supply in the energy market than economic conditions would otherwise justify” will thus “make it harder for otherwise economic resources to compete in those markets.” This will place a special burden on “renewable and limited-duration resources that rely more heavily on energy market revenues than capacity market revenue.”

The Extreme MOPR would sweep in a set of resources nearly certain to be built (indeed, for many such resources construction may already be underway), and thereby guarantee a substantial amount of duplicative costs and suppressed energy market prices. Because the Extreme MOPR lacks MOPR-Ex’s exemptions, its negative impacts in terms of wasted resources and consumer costs would only be greater.

In regions with capacity markets, the Commission has assumed responsibility to “reflect the economic value of capacity reserves” in a manner that is consistent with the region’s installed reserve margin. In other words, the Commission’s task in regulating capacity markets is to “ensure that there is enough generation to reliably meet load” without “overcharging . . . customers for unnecessary capacity.” While the Commission has reasoned that sloping demand curves may be appropriate due to their ability to induce more efficient pricing than vertical demand curves designed to exactly hit the installed reserve margins, any additional reserves must be procured in a manner consistent with their true value to the system. By entirely ignoring perfectly good capacity, the Extreme MOPR would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers

94 Id. at 57 (emphasis in original).
95 Id.
96 IPI report at 2.
would be receiving value for their money. The FPA’s requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

Further, as PJM has noted, the much more limited scope of the present MOPR and its predecessors has not presented such a massive risk of resource duplication. The Commission has never issued an order that so baldly forces customers to pay unnecessary costs and suppresses energy market prices, and the prospect of forcing customers to buy unnecessary capacity is particularly galling in this case given the massive reserve margins in PJM that clearly indicate further measures to increase supply are not necessary. Past decisions focused on deterring the construction or retention of so-called “uneconomic” generation, or preventing states from explicitly adjusting capacity prices after the fact, thereby undermining the Commission’s ability to set prices. As explained previously in section II.A.4, the state

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100 Jump Ball filing at 56 (“[D]uplication is limited in today’s MOPR, because of its narrow application to only certain gas-fired new entry resources. Consequently, existing resources selected by the state for their environmental attributes (for example) can qualify today as capacity by submitting below-cost, subsidized offers that are not addressed by the current MOPR.”).

101 As explained in Clean Energy Advocates’ Request for Rehearing of the Commission’s CASPR Order, that order was unjust and unreasonable because there was no evidence that ISO-NE’s mechanism to avoid duplicative capacity payments, the substitution auction, would work. See Docket No. ER18-619, ISO New England Inc., Request for Rehearing of Clean Energy Advocates at 31-34 (Apr. 9, 2018). With MOPR-Ex, no effort at all is made to prevent duplication. Elsewhere, the Commission has sought to avoid forcing to “pay for more resources than are necessary to provide for resource adequacy” or “provide a false signal that new investment is needed when this is not the case.” ISO New England Inc. and New England Power Pool Participants Comm., 158 FERC ¶ 61,138 at P 26 (Feb. 3, 2017). By contrast, MOPR-Ex would not even attempt to prevent redundant capacity purchases.

102 See New England Power Generators Ass’n v. FERC, 757 F.3d 283, 295 (D.C. Cir. 2014) (“LSEs are free to shape their portfolios as they choose, including with new self-supplied resources, ‘provided these new resources clear the auction.’”) (emphasis added). In fact, the particular buyer-side mitigation rules at issue in that case were designed to “prevent . . . excess capacity purchase.”).

103 See N.J. Bd. Of Pub. Utilities v. FERC, 744 F.3d 74 (3d. Cir. 2014); Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1298–99 (2016) (holding that those programs functioned by modifying the capacity prices set by the Commission). In its underlying order, the Commission invited states to seek an exemption from the MOPR where the programs reflected the pursuit of
programs at issue here entail revenue from sales of products representing environmental benefits, meaning that offers reflecting such revenue are not “uneconomic.” The Extreme MOPR would constitute a drastic and misguided modification to the MOPR that is not supported by past precedent.

Like MOPR-Ex, the Extreme MOPR would impose enormous costs on consumers, but to an even greater extent. A rough estimate of MOPR-Ex’s costs suggests they could be in the range of $14 to $24.6 billion (more than $200-300 of unjustifiable costs for every customer in the PJM footprint). Because the Extreme MOPR eliminates MOPR-Ex’s Self-Supply, Competitive, Public Entity and RPS Exemptions, its costs can only be greater. These costs would be entirely in excess of those necessary to preserve resource adequacy, and would continue to grow over time with no end in sight (because states will continue to pursue the public interests they are mandated to serve). Further, the inflated resource pool induced by the Extreme MOPR would push the energy market to operate in a less and less efficient manner with each successive delivery year.

The Extreme MOPR is fundamentally flawed. Not only will it induce entry of more resources than warranted, it sets prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM’s glut of supply. Structural problems with PJM’s market have already encouraged a massive overbuild of the system at great cost to customers, and the Extreme MOPR would make that problem far worse, taking the market in exactly the opposite direction from what is necessary.

4. The Extreme MOPR proposal shifts regulatory risk from generators to customers

Complainants suggest that another potential basis for the Commission to intervene in the markets is that the Extreme MOPR proposal would help to address the shift in risk caused by price suppression


from state subsidies from private capital to customers. In fact, the opposite is true: the proposal would insulate supply from regulatory risk by placing that risk on customers.

Contrary to Complainant’s suggestion that state programs are anticompetitive,\textsuperscript{105} competition for Renewable Energy Certificates (“RECs”) drives their price down and brings the same incentive to innovate as other forms of competition. Where eligible resources secure long-term power purchase agreements pursuant to state programs, these are often the result of winning competitive solicitations—precise revenues from RECs are not guaranteed to all eligible renewable resources under a state program. If development costs exceed the value paid pursuant to these contracts, developers and not customers must shoulder those costs. As PJM itself acknowledged in its Resource Investment Whitepaper, competitive procurements “do[] not present the same threat” it sees in administratively-determined support.\textsuperscript{106} Moreover, such power purchase agreements can offer both retail consumers and the supplier value as a price hedge. One cannot categorically conclude such financial instruments are adverse to consumer interests. Likewise, state demand response programs generally compensate resources for services provided to the distribution system, and are not a risk-transferring tool of any kind.

In contrast, the Extreme MOPR proposal protects supply from regulatory risk that could result in their being priced out of the market. As economist Gramlich explains, under normal competitive wholesale market principles, “[r]isks of public policy changes are borne by investors.”\textsuperscript{107} Just like “[a]ny product subject to health, environmental, safety, or other forms of regulation,” where “[p]roduct prices and stock values are changed every day” due to such regulations, electricity investors could see their bottom line

\textsuperscript{105} Complaint at 15 (participation of state-supported resources in the RPM “undermines robust competition because other sellers cannot compete against a substantial subsidy available only to select capacity sellers”) (quoting Jump Ball filing at 46).

\textsuperscript{106} PJM Resource Investment Whitepaper at 45.

\textsuperscript{107} Gramlich Affidavit at section VIII.
impacted by regulatory action. But under the Extreme MOPR, incumbent generators would have the assurance that the effects of certain state policies on their bottom line will be mitigated. That confidence comes at a high cost to customers, who would pay price premiums to ensure the incumbent technologies meet their revenue expectations in the face of shifting policy preferences. But, ultimately, supply should bear the consequences of the state authority’s determination of the public interest on matters outside the Commission’s jurisdiction: it is not the Commission’s charge to protect particular competitors from adverse regulatory consequences of legitimate state policies.

5. The Extreme MOPR is not just and reasonable because it seeks to undermine states’ legitimate exercise of their powers to protect their citizens.

Under the FPA, states are expressly permitted to regulate generators for the environmental harms and benefits that they impose upon their citizens. As the United States Supreme Court explained in *FERC v. Electric Power Supply Association*, the Act “makes federal and state powers ‘complementary’ and ‘comprehensive,’ so that ‘there [will] be no “gaps” for private interests to subvert the public welfare.’” Thus, the combined effect of state and federal regulation must be permitted to internalize market externalities where laissez faire market operation would harm the public interest.

Because the Commission has not assumed the mantle of internalizing these externalities on its own, states must be able to do so without undue interference from the operation of Regional Transmission Organization markets. Further, internalizing market inefficiencies, as state policies affected by the Extreme MOPR proposal do, enhances rather than reduces market efficiency by forcing generation owners to confront the true costs and benefits associated with unit operation. In restructuring, states contemplated that competition, rather than integrated resource planning, would ultimately determine the mix of resources. But, consistent with the structure of the FPA, states understood that such competition would be

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108 *Id.*

influenced by state policy, including environmental and clean energy policies such as RPS programs. States did not give up their ability to influence market outcomes through environmental policy decisions, nor did the Commission or the courts interpret them as having done so. Short of amending the text of the Act, it would be impossible for states to give up their authority and responsibility to shape the resource mix, even if they wanted to. Nor is it lawful for the Commission to attempt to reverse state environmental policies where a state has not exceeded its authority under the FPA.

If the Commission acts to prevent state environmental policies from allowing cleaner resources to “crowd out” other highly polluting generators, that would frustrate states in carrying out their core duties to protect the public from pollution. The very purpose of state policies, of course, is to induce fewer emissions and environmental impacts by replacing dirtier energy supply with cleaner sources. These policies address serious problems facing state citizens, including severe health impacts, increased mortality, and other harmful effects caused by some types of power plants and avoided by others.

The Extreme MOPR is a direct attack on state policies because it does not have merely incidental effects upon the achievement of those policies, but rather aims to undo the policies.\textsuperscript{110} Yet these programs are fully within state authority and not preempted by the FPA.\textsuperscript{111} The state policies at issue do not aim to adjust energy or capacity prices, but rather aim to address externalities caused by power production.\textsuperscript{112} By

\textsuperscript{110} Like PJM’s proposals, the Extreme MOPR would primarily target state policies directed at addressing climate change, including demand response programs, RPS programs, and zero-emission credits for nuclear generators. See generally Jump Ball filing protest at 9-19 (describing state policies targeted by PJM’s proposals).

\textsuperscript{111} See Jump Ball filing at 4 (recognizing that “states rightly may pursue ‘various . . . measures . . . to encourage development of new or clean generation’” and making clear that PJM’s filing does not raise the question “whether states have the right to act”) (quoting Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1299 (2016)) (emphasis omitted).

\textsuperscript{112} The United States Government and the Commission recently argued in an amicus brief that Illinois legislation providing subsidies for nuclear generation would not be preempted by the FPA. See generally Brief for the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance, Village of Old Mill Creek v. Star, Nos. 17-2433, et al. (7th Cir.) May 29, 2018). The federal government noted that the zero-emission
mitigating resources supported by state policies, the Extreme MOPR would have the Commission second-guess and reverse state policy determinations about the value of externalities. This is fundamentally beyond its competence and statutory role, and would transform the Commission into an environmental regulator, setting the stage for a future Commission to possibly judge and mitigate for states’ failure to regulate externalities. Because, as even PJM acknowledges “[s]ubsidies 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.” Indeed, “[d]efining a subsidy to include all government interventions leaves out an important category: It does not include the externalities associated with electricity generation.” Thus, once the Commission has taken on the role of second-guessing the values states place on addressing an externality, it is a short step to recognizing that failure to act on such externalities, too, produces an uneven playing field.

The Extreme MOPR frustrates state policies by ignoring the capacity provided by cleaner resources whose viability depends on sales of their environmental benefits. Ignoring the contributions of state-supported resources forces state customers to rely on capacity from resources that do not earn revenue from state policies, essentially requiring state customers to procure a fixed amount of capacity from gas- and coal-fired power plants. Reversing the state’s choice of generation mix in this manner “necessarily affects” the “construction” or retention of particular types of resources (those not receiving revenues deemed “Material Subsidies” under the Extreme MOPR), and is exactly the sort of “direct regulation of generation facilities” that the U.S. Court of Appeals for the D.C. Circuit stated the

 credits at issue in that case “are separate commodities that represent the environmental attributes of a particular form of power generation; they are not payments for, or otherwise bundled with, sales of energy or capacity at wholesale, and thereby fall outside of FERC’s exclusive jurisdiction over wholesale transactions.” Id. at 10.

PJM Resource Investment Whitepaper at 35 n.75.

Id. (internal quotations omitted).
Commission would not engage in when approving the Commission’s authority to create capacity markets.115

6. Complainants’ short-sighted contention that state policies threaten the RPM paradoxically sets the market on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed.

Complainants’ focus on the supposedly “adverse” impacts of state policies ignores the real challenge facing the capacity market: its structure is ill-suited to facilitating the types of resources that states want and need. Suddenly expanding the scope of the MOPR will only lead to increased conflict and uncertainty over time. Focusing on market revisions that facilitate rather than frustrate state policy choices will yield more efficient outcomes.

The Extreme MOPR would create more uncertainty and conflict over time because it provides no principled limit to the scope of Commission intervention. The amount of redundant capacity supported by customers year after year will continue to increase as states continue to adopt policies affecting the generation mix. Eventually, the unnecessary costs imposed upon customers will become untenable and a massive course correction will be necessary.

In addition to increasing redundant capacity, the Extreme MOPR’s mitigation of state policies would likely push states to achieve their goals through less efficient policy solutions. RPS programs and zero-emission credit policies are transparent in their aim to price environmental benefits. RPS programs, in particular, rely on competitive procurement, ensuring that climate goals are met through relatively transparent and efficient means. Were the Extreme MOPR to be adopted, states could avoid mitigation by adopting less transparent and less efficient policies, relying more on siting, tax code, and other policy levers. The Extreme MOPR would thus lead to market distortions that would escalate over time, become increasingly burdensome and unmanageable, and ultimately create increasing pressure for further rule

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changes—and thus, more uncertainty. Neither the market nor the public interest would be served should states be forced to rely on a narrower band of market interventions to achieve the same results.

By contrast, capacity market revisions or other actions taken by the Commission could reduce the need for state intervention in the market, increasing market efficiency. For example, as a Brattle Group report explained, “the current PJM capacity market design maintains several shortcomings that limit the full participation of seasonal capacity resources to more cost-effectively meet seasonal reliability needs.”\(^{116}\) As much as 6,000 MW of summer-only supply may be excluded from the market, due to barriers caused by the market construct. Indeed, even as planned solar installations have grown in the region, solar offers decreased 63 percent between the last two auctions (2019/20 BRA and 2020/21 BRA), starkly demonstrating how market design can deter participation.

More generally, while PJM’s markets have facilitated the construction of a large number of new gas turbines, they provide a bad fit for other types of resources. Because gas resources are frequently marginal in the energy market, over the long-term energy prices are correlated with gas prices. This provides a natural price hedge for gas resources, while other fuel-based resources are subjected to much higher risk.\(^{117}\) Resources that have relatively higher upfront capital costs and no fuel costs receive no hedge at all and are forced to procure hedges to insulate against fluctuations in the price of gas.\(^{118}\) Further,
PJM’s capacity market demand curves are set based on a generic gas combustion turbine, meaning that net CONE is pegged to the amount of revenues necessary to induce construction of this particular type of gas unit, not resources of other technology types. Importantly, the advantages gas resources enjoy—a price hedge and capacity market revenue specifically designed to cover the amount of upfront capital needed to construct—are due to PJM’s market structure, not an inherent benefit of the resource. All else equal, customers would prefer price certainty provided by resources that do not rely on fuel. Short-term marginal cost-based markets shift the risk of changing fuel prices onto suppliers who do not face fuel costs, and more importantly, onto customers.

Given PJM’s market structure, it should be no surprise that (except for resources facilitated by RPS programs and other state policies) virtually all new construction financed on a merchant basis in the region has been gas-fired.\textsuperscript{119} Gas-fired resources have relatively low upfront capital costs, and have an advantage in capacity markets, where they can offer a lower price with the knowledge that they will be able to recover a large share of fixed costs with high certainty through their low-volatility spread between energy prices and fuel costs.\textsuperscript{120} But the massive boom in gas-fired resources in the PJM region imposes a large fuel price risk on consumers, while simultaneously setting the power sector on course to create

massive amounts of pollution and other environmental impacts related to the natural gas supply chain in a manner that is at odds with state climate and environmental goals.

Many states justifiably are not pleased with this market outcome and are seeking to modify the generation mix through environmental policies and other state regulations. Yet the very best policy options to reduce the fuel-price risk that consumers face are precisely what the Extreme MOPR would frustrate. State-facilitated, long-term power purchase agreements between load serving entities and renewable energy resources with no fuel costs leave less energy that is vulnerable to the swings of PJM’s high fuel-price risk energy market. Long-term contracts also have the added advantage of making financing for capital-intensive assets cheaper, further reducing the costs and risks for customers. But the Extreme MOPR would block capacity market access for resources supported by these contracts.

In summary, while state policies affecting PJM market prices are not a problem, there are things that can be done to provide a market that better facilitates state policy choices. Focusing on those areas would increase market efficiency and investor confidence, and benefit customers rather than saddling them with unnecessary costs.

II. Conclusion.

Complainants have failed to carry their burden under section 206 of the Federal Power Act. Complainants failed to demonstrate that the current PJM MOPR is unjust and unreasonable. Moreover, they have not shown that their proposed alternative, the Extreme MOPR, is itself just and reasonable. Accordingly, the Commission must reject their complaint.

Respectfully submitted,
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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.

Dated at Washington, D.C. this 20th day of June, 2018.

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Attachment A
Pursuant to Rule 211 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, the Sustainable FERC Project, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund ("Clean Energy Advocates") respectfully submit this protest and comment on the Federal Power Act ("FPA" or "the Act") section 205 filing dated April 9, 2018 of PJM Interconnection, L.L.C. (PJM) proposing two options to increase capacity market rates in response to certain state policies targeted by PJM.

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1 18 C.F.R. §§ 385.211 and 214.
2 16 U.S.C. § 824d.
3 Docket No. ER18-1314, PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the Capacity Market (Apr. 9, 2018) ("PJM filing").
E. Demand for zero-emission energy is a market fundamental

II. Minimum offer price rule history in PJM

III. Stakeholder process

IV. PJM proposal

ARGUMENT

I. To protect the market from an illusory threat, PJM would give FERC the impossible and improper task of policing state policy

A. PJM is wrong that competitive markets are under threat

1. PJM faces no conceivable threat to reliability

2. Policy preferences have always affected market prices

3. The positive spillover effects of state policies on other states do not justify tariff revisions to insulate the PJM capacity market from those effects

4. Even assuming there were a threat, PJM's proposals do not aim at the actions allegedly causing it

B. PJM wrongly puts the Commission in the position of policing the efficiency of state policies

1. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix

2. PJM, by deeming legitimate state policies that aim to address market failures as pernicious "subsidies," places wholesale market rules on a collision course with states' core duty to protect the public

C. PJM's short-sighted contention that state policies threaten its capacity market paradoxically sets the market on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed

II. Threshold legal and procedural flaws bar the Commission from approving any of the proposed PJM proposals

A. PJM filed a set of poorly developed proposals flouting the principle of stakeholder engagement

B. PJM's filing is deficient under section 205 of the Federal Power Act

C. PJM fails to meet its threshold burden to offer a clear rationale for its proposals and substantial evidence to back that rationale

D. PJM relies on the wrong legal standard and thereby fails to provide the record necessary to approve the proposals
III. PJM's proposals both fail to meet the standard for the Commission to approve the filing under section 205 of the Federal Power Act.

A. Even under PJM's own flawed standard, PJM's proposals fail on each count.

B. At its core, PJM's proposals are based on arbitrary line-drawing, which results in undue discrimination against certain buyers and sellers.

1. PJM's definition of "actionable subsidy" is arbitrary.

2. PJM carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations.

C. Both capacity repricing and MOPR-Ex are unjust and unreasonable because they require customers to pay more for capacity than necessary to ensure resource adequacy.

1. Capacity repricing inflates capacity rates without benefitting customers.

2. MOPR-Ex forces customers to buy more capacity than needed to provide resource adequacy in PJM.

3. PJM's proposals are not warranted by any market failure.

D. PJM's proposals are not just and reasonable because they increase market uncertainty.

1. The proposals' subjective standard leads to uncertainty.

2. The scope of the RPS exemption is unclear and further clouds market expectations.

3. Market distortions that result from PJM's proposals will force further rule changes.

CONCLUSION

APPENDIX A: Analysis of MOPR-Ex RPS Exemption

APPENDIX B: Expert Affidavits and Report (appended thereafter)
SUMMARY OF ARGUMENT

Clean Energy Advocates urge the Commission to reject both of PJM's proposed mechanisms for addressing what it views as the adverse impacts of state policy on wholesale capacity markets. By design and in application, PJM's proposals target state climate policies, including state Renewable Portfolio Standards (RPS). The proposals fail to meet threshold legal standards for approval under the Federal Power Act. Both proposals are unduly discriminatory and preferential, arbitrarily imposing excessive costs on some customers and not others, and harming some resources and not others without a principled basis. Neither proposal is just and reasonable because both are based on arbitrary line-drawing, would saddle consumers with billions in extra costs without providing any resource adequacy or other benefits, and would increase market uncertainty.

PJM presents the Commission with two ill-conceived, poorly formulated proposals that pose massive implications for the function of the capacity markets, billions of dollars in cost for consumers, and threaten to fundamentally reorder the boundaries between shared federal and state authorities over the interconnected power system. It vaguely suggests a third option may be on the table (it is not), and that if the half-formed proposals it presents to the Commission are not satisfactory, invites the Commission to resolve the core workings of a complex new market design through settlement. PJM drapes its inadequate proposals in false claims of exigency, urging the Commission to adopt at least one, lest the thundering waterfall of investment in the region slow to a trickle, and starve the fat reserve margins down to a reliability risk.

PJM is wrong that its markets are under threat due to state policies. Even PJM acknowledges that the region currently has a tremendous surplus of generating capacity, obviating any concerns that market prices are too low to incent new generation and retain needed existing capacity resources. PJM's latest planning reserve margin for the summer of 2018 is 28.7.
percent—significantly higher than the recommended installed reserve margin target of around 16 percent. When looking forward at expected power builds and retirements, there appears to be no risk of a capacity shortfall in the coming years.

The vast majority of the state policies about which PJM expresses concern have been in place for years. PJM frets about state subsidy programs that in its view, “could have a material price suppression effect in the wholesale capacity market,” but it offers no evidence that the policy actions it targets are, by any measure, more impactful or concerning than the energy subsidies enacted by governments at all levels that have affected PJM market prices throughout its history. As described in the attached report of subsidy expert Doug Koplow, energy subsidies have long been pervasive at both the federal and state level, without attendant impacts on PJM's wholesale markets that have prevented that market from attracting record levels of investment.

Many of the state policies that PJM seeks to thwart have positive spillover effects enjoyed by other states, both by lowering market prices and reducing environmental externalities. Even if one state's policies were to somehow harm customers in other states, that would not justify Commission intervention to countermand those laws where they are lawfully within the state's authority.

By asking the Commission to approve policies that would either discourage or directly frustrate the achievement of state policies fully within the state's authority, PJM's proposal would place the grid operators and the Commission in the position of policing state policies, forcing the Commission to mediate essentially political proposals put forth by entities accountable to utility stakeholders rather than voters. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix; indeed, the historical evidence shows that many
PJM states enacted RPS programs at the same time or shortly after they restructured. This history belies PJM's suggestion that reliance on wholesale market competition to determine resource mix is an all-or-nothing proposition. The MOPR-Ex proposal, in particular, aims to undo state policies that are not designed to adjust energy or capacity prices, but rather to address externalities caused by power production. This runs contrary to the terms on which capacity markets were approved, by which state's retained full control to influence the generation mix through RPS programs and other policies.

PJM's proposed actions would set the market on a path toward greater conflict and uncertainty while ignoring options to facilitate the implementation of state policies in more efficient ways. The targeted state policies reflect a change in market fundamentals; more and more, end-users demand zero-emission energy. By adopting a market design that is directly at odds with the direction the market is moving, the Commission would deepen tensions between retail and wholesale objectives, ultimately undermining the competition it seeks to promote and undercutting the relevance of the wholesale capacity market to meeting market demand.

PJM's proposals suffer from numerous threshold legal and procedural flaws that warrant immediate denial by the Commission. First, in bringing this matter to the Commission, PJM ignored the clear preference of its stakeholders to maintain the status quo. Although PJM has authority to make such filings without stakeholder endorsement, doing so means that the Commission is presented with proposals that have not been fully developed and likely do not represent a fair balance among conflicting interests. Second, PJM's ambiguous and multi-faceted proposals, which invite the Commission to choose a path forward, falls short of the specificity required by section 205 of the Federal Power Act. To be properly filed under section 205, a tariff revision must "plainly" state the change sought, be sufficiently definite to take effect by
operation of law, and provide adequate notice to consumers. PJM's filing fails to meet these requirements and should therefore be rejected outright, or at minimum be characterized as a filing under section 206 of the FPA, which would also compel rejection of the filing given PJM's failure to explain or even state that its current tariff is not just and reasonable.

Even if the section 205 standard were to apply, PJM has not put forward substantial evidence to demonstrate that its market design is just and reasonable and not unduly discriminatory or preferential. PJM fails to articulate why it has targeted a particular subset of state policies, whether and by how much they suppress prices in a way that is different from other state policies, or whether the degree to which wholesale prices are affected harms resource adequacy or some other objective enough to justify the extraordinary costs of each proposal. As a final threshold legal flaw, PJM cannot demonstrate its proposals are just and reasonable because PJM relies on a standard that lacks a basis in longstanding Commission precedent and that would leave consumers without statutory protection. By relying on an erroneous, investor-focused standard, PJM fails to address how its proposals will impact wholesale customers and thereby denies the Commission the record it requires to evaluate whether the approach is just and reasonable. PJM's apparent view that what is in investors' interests is in consumers' interests is blatantly inconsistent with the Federal Power Act's clear delineation of the Commission's role in protecting consumers (even if PJM were correct that its proposal is categorically better for investors, which is not the case).

The substance of PJM's proposals is equally flawed. PJM's proposal neither demonstrates, nor is there sufficient basis to conclude, that either repricing or MOPR-Ex will in fact facilitate robust competition; provide the right price signals; result in selection of least-cost set of resources; ensure price transparency; shift risk from customers; or mitigate market power.
PJM's proposals add unnecessary complexity to the capacity market construct through a layer of unworkable administrative judgments about "what is a subsidy" that will cloud market certainty, lead to arbitrariness in price signals, and obscure price mechanics. Absent any principled economic rationale underpinning either market construct, PJM's proposals work to the benefit of certain competitors instead of competition.

PJM's definition of actionable subsidy, which underlies both the repricing and MOPR-Ex proposals, is based on a revenue threshold that even PJM admits may not affect capacity offer prices in all circumstances, much less have an impact on the market itself. PJM then carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations, without offering any rational basis for the different treatment. First, PJM provides an unfettered exemption to its definition of a subsidy for self-supply resources, contrary to its previously expressed concerns about the owners of such resources having incentives to manipulate the market if certain criteria are not met. As PJM has previously acknowledged and as recent examples show, self-supply resources can elbow other, more competitive resources out of the market. Yet PJM gives such resources a free pass, without explaining why resources supported by state programs should be treated differently. Next, PJM proposes to exempt incentives that utilize criteria designed to incent or promote general industrial development in an area, or to incent a generator to site in a particular location. PJM offers no explanation at all for its proposed exemption of general economic development and local siting incentives, despite evidence that such incentives can provide significant support to specific energy assets and affect decisions to enter the market in a particular location. Finally, PJM appears not to apply its definition evenly to all resources, as it omits thousands of megawatts of coal-fired generation resources in Pennsylvania that receive state policy benefit.
that, by PJM's own definition, is "material" and would therefore pose risk of price suppressive effect.
PJM's wholly arbitrary targeting of some state policies but not others with the same potential market effects, has severe and harmful consequences for both market participants and wholesale customers. This discrimination is not based on any meaningful economic rationale or other reasonable distinction, and therefore is by definition "undue."
The arbitrary nature of PJM's proposal results in direct harm to wholesale customers and, under MOPR-Ex, capacity sellers. Under PJM's proposals, wholesale customers in one capacity zone (where resources benefiting from "actionable" policies are located) face price increases while customers in another zone do not (where resources benefit from policies that are not deemed "actionable") – even though both customers are served by capacity resources that receive state benefits that, under PJM's reasoning, would pose the same threat to market competition. Under MOPR-Ex, market participants who have based their investments on the expectation of the regular application of certain state laws lose out; while at the same time other investors who have relied on state policies that are not deemed actionable but have the same potential market effects do not. To the extent investor expectations are a rightful subject of the Commission's just and reasonable standard at all, PJM's proposal results in exactly the unduly discriminatory application of the standard that is prohibited under the Federal Power Act.
Both repricing and MOPR-Ex would be costly to consumers, and create the possibility for drastically different prices for consumers in different capacity zones. Capacity repricing forces customers to pay more for the same level of resource adequacy by setting prices to what they would have been if state policies did not exist. By design, repricing would set prices higher than the amount necessary to induce the entry and retention of resources that cleared in the
auction's first stage, contrary to the fundamental purpose a capacity market to attract sufficient capacity to provide resource adequacy at least cost to consumers. Capacity repricing is also unjust and unreasonable because it is structured in a manner that will skew market bidding incentives in a manner that would further harm customers, as described in the affidavit of James F. Wilson attached to these comments. Under reasonable assumptions about the quantity of resources that would be repriced, Wilson calculates that clearing prices could increase 50 percent as compared to operation of the PJM capacity market under status quo rules, amounting to a total market cost of $9.1 billion annually. These staggering price increases would not provide customers with any appreciable benefits, and would therefore be unjust and unreasonable.

MOPR-Ex, by PJM's own admission, would require customers to procure more capacity than necessary to meet the region's reliability needs. By ignoring perfectly good capacity developed pursuant to state policies, MOPR-Ex would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers would be receiving value for their money. The costs of this approach are similarly staggering: a rough estimate suggests they could be in the range of $14 to $24.6 billion. The Federal Power Act's requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

MOPR-Ex is fundamentally flawed because not only will it induce entry of more resources than warranted, it sets prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM's glut of supply. Structural problems with PJM's market have already encouraged a massive overbuild of the system at great cost to customers, and MOPR-Ex would make that problem far worse, taking the market in exactly the opposite direction from what is necessary.
MOPR-Ex's proposed exemptions for certain state policies do not cure these fundamental flaws. In particular, the exemption for state RPS programs is so restrictive that many state-supported renewable resources will fail to qualify despite the legitimacy of the underlying policies. As we detail in Appendix A, there is significant uncertainty as to whether 10 of the 11 RPS programs would meet PJM's restrictive criteria. No market failure justifies that dramatic administrative interventions that PJM proposes. PJM points to the participation of resources that benefit from revenues from (some, arbitrarily-defined) state programs as warranting intervention, but it is fundamentally wrong to treat value derived from valid state property rights and obligations as "distortions" of the market. PJM is also simply wrong that the participation of resources receiving such revenues will give rise to a threat to reliability that would warrant market intervention; by its very design, market prices will rise if supply becomes low due to retirements (even assuming those retirements are driven by entry of state-supported resources). Nor does the prospect of buyer-side market power warrant tampering with the market here. To the contrary, long-standing Commission precedent holds that the renewable resources that are a primary target of PJM's proposals are an exceedingly poor tool to use in seeking to lower market prices. Moreover, because these state actions are driven by other motivations, there is little deterrence benefit of targeting them for mitigation. Finally, PJM is simply mistaken that the market interventions it proposes will have the benefit of shifting risk from consumers to supply. Its proposals will have precisely the opposite effect. For all these reasons, the Commission should reject PJM's proposals as unwarranted, vastly outweighed by the harms to customer and state interests, and unnecessary to ensure the competition that benefits the public.
Finally, the Commission must also reject PJM's proposals because they would unreasonably undermine market certainty. PJM's proposals, of which the lynchpin of each is a subjective and internally inconsistent standard, will only produce greater dispute, litigation, further rule changes, and market confusion going forward. Moreover, the scope of the MOPR exemptions are vague and do not provide clear guidance as to which state policies will be covered, which undercuts investor certainty. Placing PJM and the Independent Market Monitor in the role of determining the scope of an actionable subsidy is likely to be unworkable, and to lead to long, irresolvable disputes. Both proposals lead to market distortions that will create increasing pressure to once again change market rules to correct course, thus providing little prospect of continuity for market participants.

BACKGROUND

I. State policies at issue

At the heart of this proceeding is a series of policies that states have adopted to support the transition to clean energy. Because Clean Energy Advocates' interests in this proceeding are particularly linked to the policies that aim to incent the technological innovation, development, and widespread commercial deployment of emergent clean energy technologies (including solar, wind, demand, and storage), we focus our discussion here on those policies.

States employ a wide array of policies to foster the growth of renewable energy, energy storage, and demand response resources. State policies in support of clean energy use a variety of methods to pursue diverse goals, from spurring local economic development and improving ambient air quality to supporting emerging clean energy technologies and fighting global climate change. Many of these state programs incorporate competitive procurement mechanisms and rely on tradable credits that can be exchanged in markets.
Renewable Portfolio Standards

Renewable Portfolio Standard ("RPS") programs are well-established mechanisms by which states can encourage growth of renewable energy resources while minimizing cost. Although the details vary greatly from state to state, in broad strokes an RPS works as follows: First, a state sets progressive annual targets for power from renewable resources to make up an increasing part of its energy consumption. To meet these targets, load serving entities ("LSEs") within the state are required to obtain a percentage of their energy from "renewable" resources. States have different definitions of what constitutes "renewable," in accordance with their policy priorities. LSEs satisfy this obligation by obtaining and using renewable energy certificates ("RECs"), each of which reflects the production of one megawatt-hour of electricity by a renewable resource. An RPS thus creates a market for RECs, in which LSEs obtain RECs from the owners of renewable resources to meet their share of the state's renewable energy target. States regulate the REC procurement market in different ways. Depending on the program, RECs may be "bundled" and sold together with the underlying energy, or "unbundled" and traded separately. RPS programs may also prioritize certain kinds of renewable resources over others by creating different tiers of RECs or carve-outs for specific resources, as described in further detail below.

Beginning with New Jersey in 1999, ten states and the District of Columbia enacted RPS programs in PJM's footprint. As "inventions of state property law" RPS programs vary greatly, reflective of each state's underlying and particular policy objectives. These policy objectives include, among other things, reducing greenhouse gas emissions, diversifying the state's energy supply, and ensuring reliability of the electricity grid.

extend far beyond carbon reductions, reflecting the diverse goals and priorities of individual states. For example, New Jersey's RPS program is designed to, among other things, "encourage the development of renewable sources of electricity and new, cleaner generation technology; minimize the environmental impact of air pollutant emissions from electric generation; reduce possible transport of emissions and minimize any adverse environmental impact from deregulation of energy generation."

Virginia's RPS program is broadly based on the pursuit of "public interest."

Illinois' RPS program is premised on the basis that "environmental benefits of renewable energy generation are mainly associated with the benefits of avoiding the use of conventional generation sources that typically burn fossil fuels and emit regulated pollutants."

The law also cites state policy goals including water conservation, adverse land-use impacts, and reductions in "lung diseases such as asthma and chronic obstructive pulmonary disorder."

Michigan's program aims to, among other things, reduce "energy waste" and coordinate "with federal regulations to provide improved air quality."

Because RPS programs are founded upon diverse policy objectives, RPS program design naturally varies greatly from state to state. States reflect their different policy priorities through their decisions in RPS program design, and have charted different courses on decisions such as what types of resources qualify as "renewable", whether all or a portion of RECs should be restricted on a geographic basis, whether any resources should receive different prices from each other.

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6 N.J.A.C. 14:8-2.1.
8 20 ILCS 688/15, Sec. 1-5.
9 Id.
other or be procured in different ways reflecting their different environmental benefits and other impacts, whether the “banking” of RECs should be permitted to allow for use in future years, what the target should be in each year, and what the consequences should be were an LSE to fail to meet its requirement to procure RECs.

Qualifying Resources. RPS programs do not uniformly allow for the same set of qualifying resources differ by state. For example, whereas North Carolina allows for demand response, New Jersey does not. Indiana allows for clean coal. Qualifying resources often include a number of megawatt and entity specifications. Illinois limits qualifying distributed generation, for instance, to 2 MW or less; North Carolina limits hydropower resources to 10 MW or less.

RPS programs can also include several resource tiers to allow the state greater ability to further the particular policy goals they seek. Maryland, for example, includes hydroelectric power as a Tier II resource, which Delaware classifies it as a Tier I resource. Other state resources focus to a greater extent on waste reduction measures, such as Michigan, which includes “energy efficiency, load management, and energy conservation” as Tier I qualifying resources. Moreover, some states have designed their program to ensure particular standards in manufacturing are met. In the District of Columbia, for example, solar thermal installations must use Solar Rating and Certification Corporation certified components to qualify.

Geography. Resource eligibility can also vary based on geography. Frequently, states allow RECs from resources from across the PJM footprint to satisfy their RPS targets.
example, Pennsylvania’s RPS states, “for purposes of compliance with this act, alternative energy sources located in [PJM] or its successor service territory shall be eligible to fulfill compliance obligations of all Pennsylvania electric distribution companies and electric generation suppliers.”

Notably, this language dates to 2007, contemporaneous with the beginning of PJM’s capacity market. The District of Columbia likewise allows for resources from within and adjacent to PJM’s service territory to provide RECs.

In contrast, Indiana requires that 50% of qualifying energy be obtained from within the state. Delaware’s RPS program takes a different approach, providing credit multipliers for resources that meet certain geographic criteria that encompass and contemplate manufacturing origin.

Carve outs. RPS Programs may also preference certain types of generation in ways other programs do not. Delaware, for example, has a 3.5% solar target. Michigan provides a credit multiplier for renewable energy generated during hours of peak demand.

Maryland and New Jersey have carve-outs calling for a certain percentage of their RPS to be met by RECs from qualifying offshore wind resources.

Competitive procurement mechanisms and banking. States have different mechanisms for how the RECs may be bought and sold and when they may count toward the target in a particular compliance year. A majority of states in PJM use a common “generation
attribute tracking system” (GATS) to track RECs across the PJM jurisdiction. GATS enables states who use it to track the attributes of all registered generators within PJM, as well as some located outside but interconnected to PJM. Under the majority of state programs, some or all RECs may be purchased by Load-Serving-Entities from generators with eligible attributes throughout the PJM footprint, or beyond, through the REC market. Thus, while demand is, in effect, set by the strictness of the RPS targets, eligibility requirements, and cost containment mechanisms (such as the availability of alternative compliance payments), within these parameters generators compete in the market to supply RECs. The REC market is one means states use to ensure competition drives down costs of procurement to consumers. Not all states use a tradable REC market as the means of procurement. Illinois, for example, relies on the Illinois Power Agency to purchase RECs. Even where state programs goals cannot be met through open trading of RECs on the market, states commonly use alternative competitive procurement mechanisms. For example, with the aim of enabling the development of a promising but still nascent (in this country) offshore wind technology, the Maryland Public Service Commission employed a competitive bidding process. Where RPS programs allow for tradable RECs, states make varying decisions as to whether they can be “banked” for use in future years. In Delaware, for example, RECs last for 23 GATS is operated by an unregulated PJM affiliate. Michigan and Ohio do not use GATS, but have their own systems to track RECs. PJM Independent Market Monitor, State of the Market Report at 318 (2017). ("SOM 2017") 24 Id. at 312, Table 8-12. 25 20 Ill. Comp. Stat. Ann. 3855/1-5 (A)-(H). 26 See In the Matter of the Applications of US Wind, Inc. and Skipjack Offshore Wind, LLC for a Proposed Offshore Wind Project(s) Pursuant to the Maryland Offshore Wind Energy Act of 2013, MD PSC Case No. 9431, Order No. 88192 at 1 (May 11, 2017). (also estimating that the combined 368 MW projects would result in $1.8 billion of in-state expenditures and spur the creation of almost 9,700 new in-state jobs.)
three years but can be suspended and held by the Delaware Sustainable Energy Utility.

27 RECs last five years in Michigan, which also has tradable energy waste reduction credits and tradable advanced cleaner energy credits.

28 Target. States have opted for a range of long-term and short-term RPS program targets. Delaware and Illinois have RPS programs with a goal of 25% by 2025-2026, whereas the District of Columbia has both a 20% goal by 2020 and a 50% goal by 2032.

29 Indiana's RPS program, in contrast, is voluntary and has a 10% target by 2025.

30 Penalties. States have chosen a variety of designs around penalties and alternative compliance payments for LSEs that fail to meet RPS requirements. The District of Columbia employs a diminishing penalty structure for certain resources and a general alternative compliance payment for others.

31 Delaware has a greater penalty for solar non-compliance than non-solar non-compliance.

32 Michigan does not enforce penalties but does require certain filings before the Public Utility Commission.

33 North Carolina provides the Public Utility Commission flexibility to determine individual penalties.

30 Ind. Code §8-1-37
31 D.C. Code §34-1431 et seq.
33 Mich. Comp. Laws § 460.1022
34 N.C. Gen. Stat. §62-133.8
Beyond RECs, several states have enacted policies to encourage energy storage in recent years. For example, California has required its investor-owned utilities to deploy 1,325 megawatts of energy storage through a competitive procurement process by 2024.

In PJM’s service territory, Maryland has implemented a tax credit encouraging residential and commercial taxpayers to install energy storage systems on their property, while New Jersey recently passed legislation requiring its Board of Public Utilities to “establish a process and mechanism” for achieving 600 megawatts of energy storage in the state by 2021 and 2,000 megawatts of energy storage by 2030.

These and other state efforts to encourage nascent energy storage technology complement the Commission’s recent Order No. 841, which removed barriers to the participation of energy storage resources in wholesale markets operated by RTOs and ISOs.

Energy storage resources are not clearly targeted by PJM, as Mr. Keech’s affidavit does not include them within the scope of its estimate of resources with “subsidies that would be subject to repricing.” See PJM filing, Attachment E, Affidavit of Adam J. Keech on Behalf of PJM Interconnection, LLC (“Keech Affidavit”) at P 18. Nevertheless, we have included them here because they are potentially swept up by the logic of PJM’s proposals.


Demand response policies and programs provide a host of benefits for utilities, consumers, the local economy, and the environment. Reducing the peak demand on the utility or broader energy system can significantly reduce total system costs and consumer bills. Over a longer time period, these investments in demand response can also reduce or delay needed investment in new or upgraded distribution and transmission infrastructure and new energy generating units.

Pennsylvania's energy efficiency and conservation standard, known as Act 129, includes an “Act 129 Demand Response Program.” Under this program, commercial, institutional, and industrial customers within many of the state's investor-owned utility territories have the option to participate in utility-run summer demand response programs. For example, PPL offers its own DR programs through Act 129’s program. In PPL’s 9th year of the program (Summer 2017), the utility was able to reduce summer peak demand by an average of 126.7 MW over three DR events.

In a consultant’s evaluation of the program, PPL’s DR program was found to have
"NPV Lifetime Capacity Benefits" of $6.188 billion. This was around 6-fold more than the NPV costs of PPL's DR program ($1.04 billion).

In Maryland, Baltimore Gas & Electric (BGE), Potomac Electric Power Company, Delmarva, and the Southern Maryland Electric Cooperative all offer demand response programs for both residential and non-residential customers. For example, BGE's program includes demand response programs for air conditioning, electric water heating, and multifamily housing, as well as a “PeakRewards Trade Ally” program that rewards HVAC contractors that successfully get customers to participate and maintain their enrollment in any of BGE's demand response programs. These programs are offered as part of the state's energy efficiency program, emPOWER Maryland. The demand response programs within emPOWER Maryland helped eliminate the need for more than 2 GW of new power capacity in the region. For every dollar spent on emPOWER programs, the state saw about two dollars in benefits – which include "power wholesale prices for energy, savings from reduced demand for electricity production, and reduced need to build new power plants and power lines".

D. Benefits of state policies

Experience shows that RPSs and other clean energy programs are good investment for states, creating significant benefits that easily justify their costs. For example, Delaware found that for the period between June 1, 2014 and May 31, 2015, the benefits of the state's RPS
exceeded costs by over $22 million, taking into account impacts on the economy, air quality, and greenhouse gas emissions.

A 2016 study by the National Renewable Energy Laboratory ("NREL") shows an even higher cost-benefit ratio at the national level: assuming existing RPSs remain in effect until 2050 nationwide, the study found, these programs would lead to estimated costs of $31 billion, compared with environmental and health benefits of $97 billion and global climate benefits of $161 billion.

A further benefit of state policies fostering clean energy resources is that they create space for promising nascent technologies to mature. As the Commission recently noted in the electric storage context, "barriers to the participation of new technologies . . . in the RTO/ISO markets can emerge when the rules governing participation in those markets are designed for traditional resources and in effect limit the services that emerging technologies can provide."

By providing revenue for attributes and services not accounted for in the market, state policies can level the playing field between emerging clean technologies and incumbent resources advantaged by the status quo.

E. Demand for zero-emission energy is a market fundamental

State policies are also driven by a market fundamental: there is growing demand for clean energy by end-users, including large businesses who prioritize ready access to zero-emission electricity service. Nationwide studies document the phenomenon, with voluntary "grown
Moreover, business continues to forge ahead with even more ambitious commitments to procure clean energy. Among Fortune 100 companies, 63% have adopted clean energy targets. Nearly two-dozen Fortune 500 companies have committed to power all of their corporate operations with 100 percent renewable energy, including Apple, Bank of America, Facebook, Google and Walmart. Businesses committed to their clean energy goals make access to zero-emissions energy a core part of their decisions on where to site expanded operations.

According to the Renewable Energy Buyers Alliance, commercial and industrial buyers have contracted for about 5 GW of wind and solar power, and intend to procure an additional 60 GW by 2025. States rationally must respond to ensure the retail markets are delivering the kind of supply that is being demanded, and accordingly have developed policies that aim to overcome the significant barriers that remain to widespread commercial deployment of clean energy technologies.

II. Minimum offer price rule history in PJM

PJM’s proposals would fundamentally alter the region’s use of the minimum offer price rule (“MOPR”). As discussed further in Background section IV, capacity repricing would replace it, while MOPR-Ex would vastly extend it. MOPR has been in place in PJM for over a decade. This tracks only voluntary purchases, separate from those that meet compliance requirements. Such voluntary purchases comprise 27% of the U.S. renewable energy market in 2016. O’Shaughnessy et. al., “Status and Trends in the U.S. Green Power Market NREL (2016 data) at 5, available at https://www.nrel.gov/docs/fy18osti/70174.pdf.


See e.g., Corporate Clean Energy Procurement Index: State Leadership & Rankings Retail Industry Leaders Association, Information Technology Industry Council & CleanEdge (2017) (providing members with rankings of states that have policies to support large business clean energy procurements).

Id. at 4.
and during that time has undergone substantial change. In 2006, FERC approved a settlement adopting tariff provisions to address market power concerns in PJM's capacity market, known as the Reliability Pricing Model ("RPM"). The 2006 tariff changes first established MOPR as a means to ensure that "net buyers do not exercise monopsony power by seeking to lower prices through self-supply."

The provisions sought to "distinguish . . . net buyers that may have incentives to depress market clearing prices below competitive levels" and those without such incentives.

The Commission approved, over protest, an exception from the MOPR for capacity built pursuant to state mandate, finding that the exemption is reasonable because it enabled states to meet their responsibility to assure local reliability.

For units that had their offers mitigated, the Commission also approved an option to adjust the default bid to account for recovery of "investment costs required to comply with government-mandated requirements (such as, for example, environmental regulations)."

On rehearing, the Commission concluded that, "[m]itigation does not, and should not, protect customers from actual capacity cost increases that may be attributable to environmental requirements or other necessary investments in order to allow that generator to participate in the capacity market."

The 2006 MOPR did not contain a categorical exemption for self-supply, but rather allowed Load Serving Entities to avoid participating in the auction altogether by allowing them to commit to procuring the full amount of their capacity needs in advance for a one-year period.

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57 Id. at P 34.

58 Id. at P 104.

59 Id. at P 106.

60 PJM Interconnection, L.L.C., 119 FERC ¶ 61,318 at P 150 (June 25, 2007) ("PJM 2007 RPM Settlement Rehearing Order").
On rehearing, the Commission explained its rationale for accepting mitigation rules that did not exempt partial self-supply which would bid as a price-taker. The Commission found that the MOPR focused on the "relevant conditions" under which sellers (as net-buyers) have the ability to depress prices and profit as a result (i.e., where mitigation is able to deter exercise of market buyer power). Under those conditions, even "small additions of capacity may reduce auction prices significantly, and yield a net profit for the buyer."

In several proceedings over the years, PJM proposed adopting a MOPR that would provide substantial discretion in determining when offers are mitigated. The Commission rejected those proposed tariff changes as not just and reasonable, concluding that, "to provide needed certainty to all participants, PJM must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule."

In the wake of complaints filed related to the market effects of state measures that were ultimately held to be preempted under the Federal Power Act, the Commission approved...
sweeping changes to the PJM MOPR rules. Among other changes, the exemption for capacity built pursuant to state mandate was eliminated, though the Fixed Resource Requirement remained in place and the Commission again rejected a separate self-supply exemption.

Notably, the Commission rejected a proposal raised in a complaint filed by generators to trigger MOPR based on whether a unit received a subsidy, explaining: “we are not persuaded that determining what constitutes a ‘subsidy’ or a ‘discriminatory payment,’ as opposed to evaluating net costs, will be a less subjective and more precise means of preventing uneconomic entry.”

At the same time, the Commission approved expansion of the categories of resources that are allowed to submit zero-price offers, which already included nuclear, coal, hydroelectric, and integrated gasification combined cycle plants, to include wind and solar.

The Commission found persuasive PJM’s explanation that, compared to combustion turbine or combined cycle gas plants, “wind and solar resources are a poor choice if a developer’s primary purpose is to suppress capacity market prices.”

An entity seeking to exercise buyer market power would need to offer as much as eight times the nameplate capacity of such a gas plant to achieve the same price benefit.

In addition, the Commission agreed that the long-lead time for development of wind and solar resources provided good reason to exempt them from the MOPR.

Developers of such projects would make decisions based on “several years of auctions and energy market prices” and would necessarily begin construction and incur costs years in advance of the first
auction it could participate in. By the time such a resource participates in the BRA, “the resource would most likely have tens or hundreds of millions of dollars of sunk costs” resulting in a small or even zero net avoidable incremental cost.

In upholding expansion of the MOPR on rehearing, the Commission also openly recognized that the RPM is not designed to explicitly recognize certain legitimate state objectives, such as environmental goals. The Commission invited PJM market participants to consider how such broader objectives could be incorporated into the market design through a stakeholder process.

To date, PJM has never initiated a stakeholder process with that objective. In 2013, the Commission again considered proposed changes to PJM’s MOPR. Whereas the Commission had in 2011 rejected an exemption for self-supply resources, the Commission approved the modified version proposed by PJM because it considered the conditions PJM placed on eligibility for that exemption to be sufficient to ensure that self-supplying entities did not have an incentive to influence market-clearing prices by offering a price-taker bid.

Throughout the history of changes to the PJM MOPR, several principles have remained constant. As the Commission described to the D.C. Circuit in a case defending its rejection of several proposal changes to the MOPR, the rule was designed with a purpose “to prevent the exercise of monopsony power—that is, price suppression by utilities that offer capacity into the market but buy more capacity than they sell.” The goal is to “prevent market manipulation,”

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73 Id.
74 Id.
75 PJM 2011 MOPR Order on Rehearing at P 90.
76 Id.
and thus "[MOPR] is designed to identify new resources with the incentive and ability to depress auction clearing prices."

Further in aiming toward this objective, the Commission has always balanced the need for mitigation of buyer-side market power against the "risk of over-mitigation."

In addition, in considering the appropriate scope of MOPR's sweep, the Commission has frequently reiterated the importance of objective criteria that provide the certainty needed to market participants.

To date, because PJM's MOPR has been narrowly focused on resources that would have both the "incentive and ability" to benefit from exercising buyer market power, the Commission has not had to address the appropriateness of targeting such a large share of capacity in PJM that are being built for reasons other than the potential to financially gain by making an artificially low offer – an issue now presented in this proceeding.

In other expansions of PJM's MOPR, the targeted manipulative behavior would be deterred by the application of MOPR, because the financial benefits sought are eliminated through mitigation of the offer. As discussed further herein, that is not the case with respect to PJM's proposals.

III. Stakeholder process

PJM makes much of its "extensive process" leading up to its filing of the two alternative proposals before the Commission in this proceeding, claiming to have "initiate[d] a discussion" on the issue nearly two years ago.

The stark truth is that the majority of stakeholders have at *40 (exemptions upheld were designed to sort out resources that lack incentives to bid their actual costs).

Id. at *11.

Id. at *29.

See supra ns. 64 & 68.

PJM filing at 5. PJM's claim that it initiated "discussion" of these issues two years ago is absurd. PJM refers to its release of a general whitepaper (PJM filing at 37) that never made any mention of the proposals under consideration today, and certainly did not point to any evidence of a grave threat to the markets.

See PJM, "Resource Investment in Competitive Markets" (May 5, 2016) ("PJM Resource Investment Whitepaper"),
never been convinced that there is a problem threatening the PJM market at all, and voted convincingly in the stakeholder process to reject acting on any of the proposed capacity market reforms. Nevertheless, at every turn, PJM forged ahead with a process that appeared aimed at advancing PJM’s preconceived “solution”; while stakeholders repeatedly sought to better understand some basic questions: what is the threat to the market PJM aimed to address; what data documented that problem; and what are the consequences of PJM’s preferred approach?

After nearly a year in a stakeholder process that never delivered answers to those core questions, PJM told stakeholders that, regardless of the outcome of the vote, it would recommend that its capacity market repricing proposal be filed at FERC. Stakeholders overwhelmingly rejected PJM’s proposed capacity market reform. In the face of a flood of stakeholder letters voicing frustration by the process and grave concerns about the proposal PJM sought to advance in circumvention of the stakeholder process, the PJM board took the highly unorthodox step of filing with FERC its own preferred proposal (repricing), alongside an alternative proposal (MOPR-Ex), as well as suggesting the adoption of a third, previously undisclosed option (a second version of MOPR – essentially punting to the Commission a choice of the best policy). PJM also indicated that further development of the proposal selected by the Commission might be needed by offering the potential for settlement proceedings to address unresolved issues, essentially leaving important elements of what it had filed ambiguous.

Stakeholders engaged with PJM at twenty-two meetings over eight months on the subject of this proceeding through the Capacity Construct/Public Policy Senior Task Force available at http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx.

PJM filing at 7.
The task force was charged with evaluating the capacity construct in light of state public policy initiatives, identifying areas where the capacity construct and state actions may not be aligned, and considering modifications to the RPM that could accommodate/address both capacity market objectives and state actions.

Prior to the initiation of the stakeholder process, PJM had released its proposed approach to the topics at issue, a proposal to reform the RPM to adopt a two-tiered auction structure (what ultimately became the preferred proposal in this proceeding, the repricing proposal).

Stakeholders duly engaged on the issue presented by PJM, developing more than a half-dozen alternative proposals to better reconcile state policy action and RPM objectives. However, stakeholders became increasingly concerned by PJM's lack of engagement with some stakeholders' core concerns. Stakeholders repeatedly asked PJM to better explain and provide data to document its concerns of a threat to the market due to state actions. As the Organization of PJM States, Inc. ("OPSI") explained to the PJM Board in October, "unlike PJM's initiative to implement the Capacity Performance proposal, there has been no demonstration of facts, data, or information other than hypothetical fears supporting the concerns of the CCPPSTF."

To the contrary, PJM staff's analysis of the "Key Components" of the RPM Construct as a part of the stakeholder process showed no impact.
from the state actions reviewed. OPSI also voiced a concern that was widely shared among stakeholders in the process – PJM had set an "accelerated timeline for filing at the FERC" that it seemed unwilling to depart from. Indeed, the targeted November end to the stakeholder process was motivated by PJM's urgency to file proposed tariff language early enough to allow for the tariff to come into operation before the May 2018 auction, meanwhile many stakeholders felt frustrated that PJM was rushing to respond to an unsubstantiated concern.

In November, the task force took a straw poll to identify the proposal that would be moved forward for a vote at a higher-level committee, the Markets and Reliability Committee. The proposal that received the most support from stakeholders participating in the CCPPSTF (64 percent in favor) was to retain the status quo and not file any tariff revisions with the Commission. Because PJM did not allow the status quo to be considered as a binding option, an alternate option receiving the next highest level of support was advanced (a version that would become the current MOPR-Ex proposal).

For many stakeholders that are not closely engaged in the work of the task force, the Markets and Reliability Committee presented their first opportunity to engage with a proposal that had a serious possibility of being submitted to FERC, evaluate how it would impact their interests, and decide how to vote. In the face of its incredibly low support from the stakeholders, further development of PJM's repricing proposal (such as draft tariff language to flesh out the operation of the proposal) with stakeholders ceased.

Id. at 2.

Id. at 3.

Before the Markets and Reliability Committee could vote on the proposal, PJM issued a letter stating that, regardless of the result of the next vote, PJM would be recommending to its board to move forward with filing its repricing proposal.

In votes at the Markets and Reliability Committee on January 25, 2018, stakeholders rejected both the repricing and MOPR-Ex proposals.

An outpouring of stakeholder opposition followed PJM's announcement of its intention to unilaterally proceed with its preferred proposal, though that approach had received only 21.4% of stakeholder support. A diverse set of stakeholder groups, ranging from state commissions, consumer groups, environmental organizations, industrial consumers, transmission and generation owners, submitted letters, raising concerns that the "rushed timeline in place for the CCPPSTF proceedings prevented stakeholders from adequately reviewing and refining proposals to resolve uncertainty and build consensus"; despite the many meetings, "PJM staff failed to convince the members that Capacity Repricing is a just and reasonable proposal"; maintaining the status quo "would have been a better outcome"; and that PJM had never responded to multiple requests for data or other support for its claim that action was needed.

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**94** Letter from Joint Consumer Coalition to Chairman Schneider, Mr. Ott, and PJM Board of Managers, “Recommendations regarding PJM’s Capacity Construct/Public Policy Senior Task Force (CCPPSTF)” at 5 (Feb. 9, 2018), available at [https://perma.cc/RP2P-DD9G](https://perma.cc/RP2P-DD9G).


On February 16, PJM announced that, in light of the considerable stakeholder concern, that the question of the right path forward "should fall to the Commission as the federal policymaker not to the PJM Board."

Acknowledging that "certain elements of each proposal would benefit from further stakeholder input," PJM indicated that it would request that the Commission initiate a time-bound settlement judge proceeding. On April 9, 2018, PJM filed the proposed tariff revisions at issue in this proceeding.

IV. PJM proposal

In its filing, PJM asks that the Commission accept one of two proposed revisions to the rules governing PJM's Reliability Pricing Mechanism ("RPM") in its Open Access Transmission Tariff, commonly known as its capacity market. PJM asserts that these changes are necessary to "address supply-side state subsidies and their impact on the determination of just and reasonable prices in the PJM capacity market."

The premise of PJM's filing is that state public policies to incentivize the development or retention of certain classes of generating resources are suppressing capacity market clearing prices in a way that, in PJM's view, "adversely affects..."
incentives for new investment in the region. State renewable energy procurement mandates and zero-emission credits for nuclear facilities are PJM's primary concerns.

PJM's "preferred" proposal, known as capacity repricing, would fundamentally change how prices are set in the capacity market by determining which resources obtain capacity supply obligations in a separate run of the market optimization algorithm from the run that determines the clearing price. PJM states that this option would "accommodate" state subsidies while adjusting capacity prices in response to those policies.

Resources receiving support through state policy would still be given the opportunity to clear the auction based on their actual offer price (reflecting their rights and obligations under state law), but the clearing price paid to all resources would be determined in a second run of the algorithm in which all resources that PJM deems to have received "actionable subsidies" have their bids administratively adjusted to remove the value of the subsidy received.

PJM's alternative proposal would extend the current minimum offer price rule ("MOPR") to existing and new capacity resources of all types, while offering several unit-specific or categorical exemptions. PJM's stated objective of MOPR-Ex is to "mitigate the impact of state subsidies on wholesale prices," by adjusting offer prices for those resources before the optimization model is run to an administratively determined price floor that ignores the rights and obligations under the relevant state policies deemed to be "actionable". Under MOPR-Ex,

101 Id. at 25-26.
102 Capacity repricing is described as "Option A" in PJM's filing.
103 PJM filing at 6.
104 Id. at 59–60.
105 MOPR-Ex is denoted as "Option B" in PJM's filing.
106 Id. at 6.
such resources would only clear and earn revenues in a capacity auction in the unlikely event that the administratively determined offer price is below the market clearing price.

PJM asks the Commission to accept one of the two proposed revisions by June 29, 2018, or if the Commission determines that it must conduct further proceedings, by January 4, 2019.

ARGUMENT

I. To protect the market from an illusory threat, PJM would give FERC the impossible and improper task of policing state policy.

PJM exhorts the Commission that “now is the time” for urgent action. PJM alludes to a looming threat to reliability because of state subsidies, but in making this claim PJM is akin to a man neck-deep in water, shouting that drought is imminent. Nowhere in the market is there any sign of a systematic lack of adequate capacity to threaten reliability, to the contrary by all measures it is at an excess; and investor appetite to enter the market remains voracious. Claiming an urgent threat to entry is belied by all objective standards and is not credible.

If, on the other hand, the alleged looming threat is not to entry, but instead some longer-term threat in the making due to a sudden upsurge in state policy action – this claim, too, is not backed by the facts. More than half of the capacity and the vast majority of resources targeted by PJM’s proposal are supported by state laws and policies that have been on the books for years (in some cases, since the capacity market’s inception); only a single Illinois plant is supported by a state policy of any recent vintage. Indeed, national, state, and local government incentives and

107 Id. at 7–8.
108 PJM filing at 36.
109 Id. at 19.
110 PJM identified 698 MW of RPS program resources, 981 MW of demand response or price responsive demand resources, and one 1400 MW nuclear generator. See PJM filing, Keech Affidavit at P 18. We note that one additional potential state law is pending in New Jersey at the time of this filing, which would not be accounted for in those figures.
other forms of support are pervasive in the energy sector and have shaped market participant behavior since the formation of the RPM.

If investment and decision to enter the market were materially stymied by the presence of these preferences, the capacity market today would not display the strong fundamentals that PJM hails in its filing.

Perhaps, PJM's true concern is ensuring the appropriate exit of resources in light of booming investment and capacity above reserve margins. If so, its preferred policy proposal is wholly off the mark, as capacity repricing does virtually nothing to change incentives to exit the market while MOPR-Ex affirmatively sends a signal to unnecessary resources to remain. And both proposals target policies incenting new entry, rather than focus solely on policies deterring exit of existing resources. In short, PJM proposes the rushed adoption of complex new market rules because of a "growing threat[]" that is wholly imagined.

In response to an illusory crisis, PJM would make FERC the policeman of the countless policies that potentially affect the competitive markets. PJM's alternate new market constructs are each based on a highly subjective determination of the scope of a "subsidy," which would thrust the Commission into the impossible role of arbitrating which among the ubiquitous forms of federal, state, and local preferences that shape market behavior must be unwound from the wholesale market in order to protect "competition." The standards offered by PJM to achieve this

We also cannot account for whether any state laws supporting the state demand side resources are recent, because PJM has provided no explanation of what these resources are or why they are targeted.


infra section I.A.2.

PJM filing at 10-11 (inter alia, tens of thousands of MWs of new entry in the face of low load growth and historically low energy prices; "robust" reserve margins; and continued investment).

PJM filing at 35.
objective lack internal consistency and economic rigor, and do not provide any objective, limiting principle to constrain an otherwise monumental task.

Once the camel’s nose is under the tent, the Commission will find itself far afield from its core competencies, policing all manner of government interventions (e.g., targeted federal grants for carbon capture and storage or regional natural gas infrastructure; state tax incentives for coal production; and local incentives that do not flow through economic development authorities) that affect market participant behavior and could impact market outcomes. Moreover, because the governmental entities providing these incentives are as a rule aiming to advance their constituents interests and not reap financial advantage in the wholesale markets, PJM’s new market constructs would do little to deter these activities and could instead force policymakers to shift to less transparent (and correspondingly less economically efficient) means to achieve their policy objectives. At the same time, the Commission’s unprecedented role in deciding how much and which kinds of government intervention go too far will amplify conflict between the states and retail authorities that have voluntarily joined the deregulated markets, heightening the tensions that already exist given the shared federal and state responsibility for the inextricably intertwined electricity system. In the end, the complex and unnecessary new market rules PJM proposes do nothing to benefit competition in the markets (indeed, as we show in section III, these new rules would harm market outcomes) and would put the Commission in a role Congress never intended.

The following section dissects each of PJM’s purported claims that urgent action is needed, and finds each unsupported. The subsequent section goes on to examine how PJM’s

With important exceptions. Certain policies aiming to support the development of emerging technologies, such as offshore wind, may not be viable if they are cut off from wholesale capacity market revenues.
proposals inappropriately place the Commission in a role beyond that envisaged by the Federal Power Act, forcing unproductive and unnecessary conflict with the states.

A. PJM is wrong that competitive markets are under threat

PJM alludes to a series of potential threats to the market that warrant the Commission's urgent intervention: (1) the RPM will fail "to produce the needed investment to serve load and reliability" if some supply bids "noncompetitively"\(^\text{115}\); (2) "programs which target large-scale, unit specific resources represent a serious escalation in the status quo"\(^\text{116}\); and (3) the targeted subsidies adversely affect other market participants.\(^\text{117}\)

But there is simply no evidence that investment in PJM is lacking, reliability is threatened, that the impacts of government preferences on the wholesale market now are larger than ever before; or that the programs targeted have any different or more harmful impacts than policies that have long affected the markets. As scholars at the Institute for Policy Integrity summed up their own assessment, "[t]here is no credible evidence that externality payments [the policies targeted by PJM] threaten the viability of markets."\(^\text{118}\)

1. PJM faces no conceivable threat to reliability

PJM states that "a market that does not fairly value the costs of meeting reliability needs will not continue to commit the resources needed for adequacy that compete only on their true net costs."\(^\text{119}\)

However, PJM could not conceivably substantiate a claim that PJM's market faces any foreseeable threat to resource adequacy, and does not try to do so. Objective standards of the...
market's performance simply would not support such an assertion. PJM's vague suggestion that the state programs targeted by PJM may, one day, impact the market's reliability is laden with unanalyzed assumptions and, even if it were not fundamentally flawed from an analytical perspective, as described in section III.94I.C, would amount to little more than rife speculation.

The idea that market prices are too low to support new entry is defied by the tremendous amount of new build entering PJM in spite of already high reserve margins. PJM's latest planning reserve margin for the summer of 2018 is 28.7 percent. This is significantly higher than PJM Staff's recommended installed reserve margin target of between 15.8 and 16.1 for delivery years 2018/2019 through 2021/2022.

Further, when looking forward at expected power builds and retirements, there appears to be no risk of a capacity shortfall in the next few years. As shown in Figure 1, there are over 20 GW of new natural gas capacity under construction or in advanced development expected to enter operation by the end of 2021. An additional 18 GW of natural gas capacity has been announced or is in early development. At the same time, only 7.4 GW of fossil and nuclear capacity have announced and approved retirement dates between now and 2021, according to PJM offers only conditional and evasive assertions of an actual threat to reliability. See e.g., id. at 38 ("PJM's continuing ability to deploy market forces to efficiently and reliably handle a changing resource mix may be threatened if the promotion of other policy interests are pursued in a way that materially distorts price outcomes in PJM's capacity and energy markets.") (emphasis added).


By 2021, PJM could see a net addition of up to 40 GW, even as load is expected to see relatively little growth over the same timeframe.

There is no evidence at all to suggest the investor appetite in the PJM region is on the wane, although all of the state policies targeted by PJM’s proposals have been fully on record for investors to take into account for well more than a year (and in the vast majority of cases, closer to a decade). A recent, informal poll at the Platt Global Power Markets Conference found that a large plurality (45 percent) of respondents “think that PJM is the best place where investors are...”

![Table](image)

**Estimated Year Online**

<table>
<thead>
<tr>
<th>New Capacity in PJM (MW)*</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023 NA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>11,444.7</td>
<td>1,182.0</td>
<td>5,323.4</td>
<td>2,662.0</td>
<td></td>
<td>43.2</td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>2,025.4</td>
<td>2,359.0</td>
<td>6,224.8</td>
<td>7,418.5</td>
<td></td>
<td>2,059.2</td>
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<tr>
<td>Renewables</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>1,164.1</td>
<td>545.3</td>
<td>73.7</td>
<td>10.9</td>
<td>34.0</td>
<td>220.2</td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>1,301.7</td>
<td>3,180.8</td>
<td>2,413.7</td>
<td>-</td>
<td>1,006.0</td>
<td>50.0</td>
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<td>Other</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Under Construction &amp; Advanced Development</td>
<td>60.0</td>
<td>135.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>114.1</td>
</tr>
<tr>
<td>Announced &amp; Early Development</td>
<td>11.6</td>
<td>11.6</td>
<td>0.8</td>
<td>-</td>
<td>-</td>
<td>1,754.1</td>
</tr>
<tr>
<td>Total Capacity Announced or In Development</td>
<td>16,007.6</td>
<td>7,413.7</td>
<td>14,036.4</td>
<td>10,080.5</td>
<td>1,016.9</td>
<td>84.0</td>
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<tr>
<td>Announced Retirements</td>
<td>5,587.1</td>
<td>1,707.6</td>
<td>118.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cumulative Net Capacity Change (High)</td>
<td>10,420.5</td>
<td>16,126.6</td>
<td>30,045.0</td>
<td>40,125.5</td>
<td>41,142.3</td>
<td>41,226.3</td>
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<tr>
<td>Cumulative Net Capacity Change (Low)</td>
<td>7,081.7</td>
<td>7,236.4</td>
<td>12,515.5</td>
<td>15,177.5</td>
<td>15,188.4</td>
<td>15,222.4</td>
</tr>
</tbody>
</table>

Source: S&P Global Market Intelligence. *When a unit development is publicly announced, S&P MI initiates coverage. Future units listed only in an interconnect queue are not considered; some additional public announcement or permitting action must be taken to initiate coverage. A project is updated to early development when the permitting process begins. A project is moved to advanced development when two of following five criteria have been achieved: financing in place, power purchase agreement signed, turbines secured, required permits approved, or contractors signed on to the project. A project is updated to construction begun when construction of the units begins; site preparations are not under construction.
likely to earn a targeted rate of return on new generation.

This was more than double the next highest polling region (20 percent).

As PJM itself stated in the Resource Investment Whitepaper cited in its filing, "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."

PJM succeeded at attracting substantial investment at the same time its member states have pursued their own policies to incentivize certain types of generation. Indeed, while PJM states in its filing that "[a] part-subsidized/part-competitive market is thus a very poor design choice for the critical function of ensuring reliability," PJM has successfully run a "hybrid" market for decades without any reliability crisis. PJM became the first fully-functioning U.S. independent system operator and then regional transmission organization in 1997 and 2002, respectively.

By that time, member utilities in New Jersey were already complying with state policies including renewable or alternative energy standards and energy efficiency resource standards.

As additional utility territories were added into PJM's footprint over the next three years, Delaware, Pennsylvania, Maryland, and the District of Columbia also implemented new state policies supporting the development of renewable and other resources.

By the end of the decade, 10 states within the PJM territory had adopted state policies promoting and/or mandating...
renewable energy technology adoption and energy efficiency savings levels. Three states were also members of a regional carbon market.

As shown in Figure 2 below, despite this concurrent growth of PJM's footprint and state energy policies since the early 2000s, the region was routinely able to attract new capacity under both the current RPM design and earlier market structures.

Figure 2: Capacity Additions and Retirements in PJM Region

There is also little evidence that state policies supporting renewable energy development have had or are having a measurable impact on market prices or investor confidence. The largest source of new builds, both historically and the near-term future, are natural gas facilities. As shown in Figure 3, around 95 percent of all projects identified by S&P Global Market Intelligence, Power Plant Units Database and Screener Tool, Subscription required, available at https://www.spglobal.com/marketintelligence/en/...
Intelligence as under construction or in advanced development within the PJM footprint are natural gas projects. Just five percent are wind and solar energy. Even when accounting for all stages of development, wind and solar projects represent just a quarter of all projects in S&P’s tracking database.

Policy preferences have always affected market prices. PJM claims that while one must “accept a tradeoff between perfect competition and interventions that affect price outcomes for the benefit of some at the expense of others,” recent policy actions represent a “serious escalation” in the status quo.

PJM points to the “emergence of multiple specific, substantial state subsidy programs that,” in its view, “could have a material price suppression effect in the wholesale capacity market.” Yet it offers no evidence that the policy actions it targets are, by any measure, more impactful or concerning than the pervasive policy choices by governments at all levels that have affected PJM market prices throughout its history.

---

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Operating</th>
<th>Under Construction</th>
<th>Advanced Development</th>
<th>Early Development</th>
<th>Announced</th>
<th>Mothballed</th>
<th>Out of Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass &amp; Waste Energy</td>
<td>2,148.7</td>
<td>-</td>
<td>-</td>
<td>11.2</td>
<td>104.4</td>
<td>-</td>
<td>10.2</td>
</tr>
<tr>
<td>Coal</td>
<td>64,351.9</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>12.5</td>
</tr>
<tr>
<td>Gas</td>
<td>87,994.4</td>
<td>15,424.1</td>
<td>5,231.2</td>
<td>18,628.4</td>
<td>1,458.5</td>
<td>110.6</td>
<td>58.4</td>
</tr>
<tr>
<td>Oil &amp; Other Non-Renewables</td>
<td>8,787.4</td>
<td>20.0</td>
<td>175.0</td>
<td>44.0</td>
<td>18.5</td>
<td>-</td>
<td>31.8</td>
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<tr>
<td>Nuclear</td>
<td>35,785.1</td>
<td>-</td>
<td>-</td>
<td>1,600.0</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Water</td>
<td>8,369.0</td>
<td>-</td>
<td>98.3</td>
<td>389.3</td>
<td>5,505.3</td>
<td>-</td>
<td>15.9</td>
</tr>
<tr>
<td>Wind</td>
<td>8,036.9</td>
<td>585.6</td>
<td>647.7</td>
<td>9,211.5</td>
<td>3,136.0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Solar</td>
<td>2,315.2</td>
<td>301.6</td>
<td>437.1</td>
<td>3,105.2</td>
<td>209.9</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Total</td>
<td>217,768.6</td>
<td>16,311.3</td>
<td>6,587.3</td>
<td>32,989.6</td>
<td>10,423.6</td>
<td>110.6</td>
<td>128.8</td>
</tr>
</tbody>
</table>

Source: S&P Global Market Intelligence. When a unit development is publicly announced, S&P MI initiates coverage. A project is updated to early development when the permitting process begins. A project is moved to advanced development when two or all of the following five criteria has been achieved: financing in place, power purchase agreement signed, turbine secured, required permits approved, or contractor signed on to the project. A project is updated to construction begun when construction of the units begins; site preparations are not under construction.
Indeed, it is not at all clear what manner or scale of "subsidy" PJM believes has the greatest impact on market prices. PJM suggests that it is "programs which target large-scale, unit specific resources" that present a new threat, but PJM does not explain why that is so. Nor does PJM focus its proposals on such programs. Instead, more than half of the capacity targeted by PJM's proposals are renewable, demand response, and price responsive demand resources, which are by their nature typically not "large-scale" resources, and comprise a small percentage of the resource base in PJM.

Historical data demonstrates that government policies have provided substantial support targeted toward specific types of capacity resources, including large-scale ones that comprise a significant share of capacity in the PJM market. There is no reason to believe that historic policy actions would have any less impact on market prices than PJM contends they do today. In 1989 alone, for example, coal-fired generators benefited from nearly seven and a half billion dollars in federal government support, and natural gas fired generators a little less than one billion.

On average, federal subsidies to conventional generation amount to roughly eleven percent of

Subsidy is a subjective term that imputes a value judgment. The term implies a government transfer of value (directly or indirectly) that would otherwise have had to be purchased in market place. The term should not be applied to state policies that address well-documented market failures. The state policies targeted by PJM largely address the externalities imposed by climate change, for which there are objective estimates of the public value. The Interagency Working Group on Social Cost of Greenhouse Gases estimated the social cost of carbon to be roughly $50 per ton in 2010 (in 2007 dollars and using a 2.5% discount rate).


PJM filing at 15.


Including nuclear, hydro, coal, gas, and oil.
It defies reason to suggest that support of this magnitude did not affect the composition of capacity resources, providing advantages to some resources and not others, and affecting wholesale prices. Indeed, subsidy expert Koplow concludes that historic subsidies that have underwritten long-lived capital investments would have "the same type of market effect as current subsidies."

The same basic principle would apply, "regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted."

And while renewables are "late entrants" to the scene, incumbent generators have received many large state tax breaks that are documented as far back as the 1950s, 60s, and 70s.

3. The positive spillover effects of state policies on other states do not justify tariff revisions to insulate the PJM capacity market from those effects. PJM argues that urgent intervention into the markets is warranted because "the effects of state subsidies to sellers that offer into PJM markets are not confined to the State." This logic is flawed because it could be used to justify action to adjust for any type of state regulation, transforming the Commission's role from its narrow oversight of wholesale sales of electric energy as a shared regulator of the electric sector into an agency responsible for addressing labor practices, environmental regulation, and much more. Furthermore, PJM's rationale makes no sense because state policies providing additional compensation to generators benefit rather than harm customers in other states.

Id at 20.

Koplow report at 1.

Id at 4.

Id at 17. Federal tax breaks for conventional energy go back even earlier in the history of the energy sector.

PJM filing at 29 (altered to lowercase from the original heading title).
Under PJM's theory that subsidized entry lowers market clearing prices, one state's policy providing compensation to a generator essentially provides customers in other states with lower-cost, subsidized capacity. It is hard to see how lowering the cost of supply for customers in other states is a hardship for them. Further, while the dynamic price effects are less certain, the very clear consequence of state climate policies is to positively impact all customers by reducing harmful emissions. Indeed, by PJM's logic, it would have a more powerful case for adjusting prices in response to state policies setting pollution standards, or adopting emissions-based taxes or fees. According to PJM's reasoning, such taxes and regulations would have the natural effect of raising capacity prices for all customers in the region in the near-term, because generators emitting the harmful pollution would need to factor the cost of purchasing allowances into their offer prices, pushing the clearing price higher. The case for spillover to other state customers would be far clearer, because other states would pay higher prices. Yet no one has ever

As discussed in section III.C.3.b, these spillover effects do not necessarily include lower capacity prices, due to the dynamic actions of other market actors in response to the policy.


IPI report at i, 14.

See 42 U.S.C. § 7416 (providing states with authority to set air pollution standards that are more protective than federal law); 42 U.S.C. § 7410 (providing states with authority to choose how much to limit emissions from certain stationary sources in order to meet ambient air quality standards); James Temple, MIT Technology Review, Surge of Carbon Pricing Proposals Coming in the New Year (Dec. 4, 2017), available at https://perma.cc/N3EU-B9HR (explaining how states have used this authority to adopt programs that require generators to purchase allowances to emit certain types of harmful pollution, like sulfur dioxide, nitrogen oxide, and greenhouse gases).

As explained in section III.C.3.b below, well-telegraphed or longstanding state policies will not in fact change prices in this simple manner because other market participants will take the state regulations into account.
understood this to empower grid operators to impose and the Commission to approve measures that insulate the market from the effects of those policies by adjusting downward the offer prices of affected generators. Were the Commission permitted to reverse state environmental taxes or fees in this manner, its role would transform into that of an environmental regulator because it could pick and choose when to effectively reverse those state environmental policies by making adjustments to its power markets in direct response to them.

Nor would either of PJM's proposals lessen any conflict between states that could be caused by the inevitable spillover effects that any policy will have. PJM's proposals both harm all customers in the entire applicable capacity zone as a direct consequence of one state's policy adoption and in proportion to the amount of MW supported by that state. PJM rules thus creates a far worse spillover concern, thereby increasing rather than decreasing the potential friction between them. As discussed in section I.B below, PJM's proposals, and particularly the MOPR-Ex proposal, would likewise thrust PJM and the Commission into an environmental policymaking role.

While PJM argues that state policies supporting generation could raise total costs in the long run, even if that were true, customers in the states enacting the policies at issue would be the ones to shoulder the burden while customers in other states would come out ahead (not having to cover the costs of the state program). Further, if true, PJM's prediction of eventual cost increases destroys its case that the market structure creates misaligned incentives by which states can enact subsidies because the costs are "underwritten by other participants in the wholesale..."
Rather, under PJM's theory, states would only enact programs when their benefits outweigh these long run costs, and there would be no need for the Commission to step in. PJM has presented no analysis or economic theory indicating that customers in other states would be harmed under the status quo operation of its markets. If PJM is arguing for the Commission to "protect" a state's customers from that state's own policies, that makes little sense. State policymakers, not the Commission, are in the best position to decide whether the benefits of clean energy warrant any costs those policies may impose on state customers.

4. Even assuming there were a threat, PJM's proposals do not aim at the actions allegedly causing it. PJM's articulated fear is that "owners of these legacy assets" may "seek out-of-market support from states to forestall retirement and defeat the design objective of PJM's market, at the expense of their competitors and wholesale consumers."

Likewise, the Independent Market Monitor seeks to prevent the spread of "subsidies . . . requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units" rather than "to accomplish broader social goals."

Even assuming, arguendo, the potential spread of unit-specific subsidies warranted the high costs of intervening in the market and overturning states' legitimate role, it is clear that PJM's goal could be accomplished through a far narrower measure adjusting only for the effect of subsidies targeting specific existing units that have become uneconomical under the bargain by which they were built. Yet the options presented by PJM leave states free to develop unit-
specific subsidies, through "county-specific" measures or through programs couched as industrial development initiatives. Instead, PJM primarily targets state climate policies, whether or not they focus on particular existing units. Both of PJM's proposals target the vast majority of state policies designed to spur the construction of new renewable resources. Programs such as the offshore wind mandates in several states are clearly intended "to accomplish broader social goals" and are not an example of rent-seeking by owners of units that have become uncompetitive. Moreover, the majority of state programs designed to spur renewables are competitive, awarding credits to the developers of new resources rather than to particular units seeking a handout for reasons unrelated to environmental objectives.

In sum, PJM fails utterly to back its claims of crisis. But even if it had done so, PJM's proposals are entirely misaligned to resolve the threats to the market it alleges are looming on the horizon.

B. PJM wrongly puts the Commission in the position of policing the efficiency of state policies. PJM presents states with a stark choice: rely on competitive markets, or retain full policymaking authority, but not both. In doing so, it misunderstands the structure of the Federal Power Act and the history of state restructuring. PJM would thrust itself, the Independent Market Monitor, and ultimately the Commission into an environmental policymaking role that each is ill suited to play. MOPR-Ex's intrusion into the state policy-making sphere is blatant and extreme. While PJM's capacity repricing proposal is more accommodative of state choices, it would nonetheless impose a penalty on states for enacting certain policies to regulate generation mix.

157 See supra section I (describing state policies).
158 Setting aside the different question of whether these programs would meet the overly-restrictive eligibility requirements of the MOPR-Ex RPS exemption.
but not others, prodding them to design potentially less efficient policies that do not meet the definition of "actionable subsidies" and raising the specter of further intervention in the future. In forcing states between a rock and a hard place in this manner, PJM invites the Commission to undermine the very principle of encouraging competition that PJM purports to cherish. Such tactics surely are not the way to encourage more utilities and states to join organized wholesale markets, or to entice currently vertically integrated states to join the competitive market paradigm. While states have greatly benefited from the Commission's competitive markets, their policymaking authority is even more fundamental. With the impacts of climate change already harming states citizens and prognostications of the future without urgent policy response growing increasingly more dire, states' push toward clean energy is inexorable. Ignoring that demand fundamentals are moving the future of the energy sector toward zero emissions energy only risks making a capacity market that resists those forces irrelevant, or worse, detrimental to proper market functioning. PJM's proposals would greatly reduce the appeal of its markets while harming customers in the process. Rather than accepting PJM's invitation to stoke tension between wholesale and retail objectives in this manner, the Commission should instead reject both proposals and focus on market reforms that enhance efficiency while facilitating state choices.

1. States did not give up jurisdiction under the Federal Power Act over generation when they restructured, and did not cede to the Commission sole responsibility to determine resource mix.
   PJM argues that "the fully restructured states in the PJM region elected to rely on competitive markets as the means to select resources needed to serve loads." That argument is wrong as a matter of fact, and misunderstands the respective roles of the Commission and states.

   159 PJM filing, at 21-24.
under the Federal Power Act. In restructuring, states contemplated that competition rather than integrated resource planning would ultimately determine the mix of resources. But, consistent with the structure of the Federal Power Act, states understood that such competition would be influenced by state policy, including environmental and clean energy policies such as renewable portfolio standards. States did not give up their ability to influence market outcomes through environmental policy decisions, nor did the Commission or the courts interpret them as having done so. Short of amending the text of the Federal Power Act, it would be impossible for states to give up their authority and responsibility to shape the resource mix, even if they wanted to. Nor is it lawful for the Commission to attempt to reverse state environmental policies where a state has not exceeded its authority under the Federal Power Act.

In declaring that state restructuring legislation dictated that PJM's markets would be the sole determiner of resource mix, PJM cites the decisions of four states as evidence: Illinois, Maryland, New Jersey, and Ohio.

Yet every single one of these states has had a renewable portfolio standard for roughly a decade or more. Two of the states, New Jersey and Ohio, adopted renewable portfolio standards in tandem with or as part of restructuring legislation, making abundantly clear that they were not ceding any authority over resource mix as part of their decision to restructure. The following table demonstrates that RPS are the norm among states that have pursued restructuring, both within and outside of PJM.
<table>
<thead>
<tr>
<th>State</th>
<th>RPS + Restructuring Context</th>
<th>Established in</th>
<th>Target</th>
<th>Applies to</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>Established in tandem with restructuring (1998), applies to utilities and retail suppliers; 28% by 2020; requires utilities enter long-term contracts (15 years)</td>
<td>1998</td>
<td>2020</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>DE</td>
<td>Established in 2005, applies to utilities and retail suppliers; 25% by 2025.</td>
<td>2005</td>
<td>2025</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>IL</td>
<td>Established in 2007 as part of restructuring reform legislation that created the Illinois Power Agency (IPA) which procures power for default service; 25% by 2025 for both utilities and retail suppliers.</td>
<td>2007</td>
<td>2025</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>ME</td>
<td>Established as part of initial restructuring legislation; 40% by 2017, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2017</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>MD</td>
<td>Established in 2005; 25% by 2020, applied to all utilities and retail suppliers.</td>
<td>2005</td>
<td>2020</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>MA</td>
<td>Established as part of initial restructuring legislation; 15% by 2020, with 1% each year thereafter, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2020</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>NH</td>
<td>Established in 2007; 25.2% by 2025, applies to both utilities and retail suppliers.</td>
<td>2007</td>
<td>2025</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>NJ</td>
<td>Established in tandem with restructuring (1999); 50% by 2030, applies to both utilities and retail suppliers.</td>
<td>1999</td>
<td>2030</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>NV</td>
<td>Established as part of its 1997 restructuring legislation (restructuring indefinitely halted in early 2000s); 25% by 2020.</td>
<td>1997</td>
<td>2020</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>NY</td>
<td>Established in 2004; 50% by 2030, applies to all utilities and retail suppliers</td>
<td>2004</td>
<td>2030</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>OH</td>
<td>Established in 2008 as part of broad restructuring reform legislation; 12.5% by 2026, applies to both utilities and retail suppliers.</td>
<td>2008</td>
<td>2026</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>PA</td>
<td>Established in 2004; 18% alternative energy, applies to both utilities and retail suppliers.</td>
<td>2004</td>
<td>2017</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>RI</td>
<td>Established in 2004; 38.5% by 2035, applies to both utilities and retail suppliers.</td>
<td>2004</td>
<td>2035</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>TX</td>
<td>Established during restructuring transition (1999); 10 GW of RE capacity by 2025.</td>
<td>1999</td>
<td>2025</td>
<td>Utilities and retail suppliers</td>
</tr>
<tr>
<td>DC</td>
<td>Established in 2005; 50% by 2032, applies to both utilities and retail suppliers.</td>
<td>2005</td>
<td>2032</td>
<td>Utilities and retail suppliers</td>
</tr>
</tbody>
</table>

The history of these state laws, which is consistent with that of many other states in other regions across the country, makes clear that the competition states had in mind was a framework where resource mix was determined not only by competition to sell electric energy, but also through competition to sell credits representing environmental benefits associated with power production from certain types of resources. Indeed, the restructuring boom of the 1990s coincided directly with the adoption of many state renewable portfolio standards across the country, as shown in the chart below:

**Figure 5: Historical Progression of RPS and Restructuring**

Recently Adopted RPS: CO, HI, MD, NY, RI (2004); DC, DE, MT (2005)
Recently Revised RPS: CA, NJ, NM, PA (2004); CT, NV, TX (2005); WI, NJ (2006)
In this process, states clearly retained the power to determine the types of resources eligible to serve load: Renewable portfolio standard legislation specifically dictates that a specific percentage of the resource mix in each year shall be composed of renewable resources. States, not the Commission, would dictate the terms of the competition to sell environmental benefits, including defining what constitutes "renewable", specifying whether specific types of resources would get any additional bonuses or carve-outs, and determining whether competition would be open to all resources of that type or only to new construction.

This history belies PJM's suggestion that reliance on wholesale market competition to determine resource mix is an all-or-nothing proposition. Judicial precedent affirming the Commission's authority over capacity markets confirms that states retained full authority to dictate the resource mix, including through decisions as granular as regulations designed to determine the viability of particular power plants:

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State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission."

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The structure of the capacity markets thereby explicitly contemplated that the Commission would merely set a reserve margin to be met through competition as influenced by state environmental and other policies, including actions as drastic as forbidding the construction of a specific unit.

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See supra Background Section I.A.

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These rights retained by states and municipal authorities are meaningless if FERC can ignore or block market access for resources preferred by states even where states are not exceeding their authority under the Federal Power Act.
Finally, it is axiomatic that what can be accomplished through state regulation can be undone through state regulation. Even if true that actions by Illinois and other states were a retrenchment toward a regulatory paradigm closer to traditional cost-of-service ratemaking, the states have full authority to reverse course. Indeed, the legislation establishing the Illinois Power Authority which procures power for default electricity service for Illinois customers has been cited as a step towards "re-regulation" in state commission reports.

PJM, by deeming legitimate state policies that aim to address market failures as pernicious "subsidies," places wholesale market rules on a collision course with states' core duty to protect the public.

PJM frames its proposed options as means to deter states from adopting policies to affect the electricity generation mix, suggesting a goal of the market construct should be to ensure competing resources are not "crowded out" by state-sponsored resources.

But if the Commission acts to prevent state environmental policies from allowing cleaner resources to "crowd out" other highly polluting generators, that would frustrate states in carrying out their core duties to protect the public from pollution. The very purpose of state policies, of course, is to induce fewer emissions and environmental impacts by replacing dirtier energy supply with cleaner sources. While PJM essentially admits that its proposals "countermand" state policies,

the Commission cannot properly approve a proposal whose purpose is to do so. State policies address serious problems facing state citizens, including severe health impacts, increased


167 PJM filing at 14.

168 See id. at 71 (suggesting that capacity repricing should not apply to federal tax credits because the Commission may not "countermand" acts of Congress, implicitly admitting that its proposal would "countermand" the applicable state policies).
mortality, and other harmful effects caused by some types of power plants and avoided by others.

The MOPR-Ex proposal, in particular, is a direct attack on state policies because it does not have merely incidental effects upon the achievement of those policies, but rather aims to undo them.

Unlike other state subsidy programs that PJM has sought to neutralize through application of MOPR in the past, the policies targeted by PJM's proposals are fully within state authority and not preempted by the Federal Power Act.

The state policies at issue do not aim to adjust energy or capacity prices, but rather aim to address externalities caused by power production. By mitigating resources supported by state policies, PJM's MOPR-Ex proposal would have the Commission second-guess and reverse state policy determinations about the value of externalities. This is fundamentally beyond its competence and statutory role, and would transform the Commission into an environmental regulator, setting the stage for a future Commission to judge and mitigate for states' failure to regulate externalities. Because, as even PJM acknowledges "[s]ubsidies 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."

Indeed, "[d]efining a subsidy to include all government interventions leaves out an important category: It does not include the externalities associated..."
Thus, once the Commission has taken on the role of second-guessing the values states place on addressing an externality, it is a short step to recognizing that failure to act on such externalities, too, produces an uneven playing field. MOPR-Ex frustrates state policies by ignoring the capacity provided by cleaner resources whose viability depends on sales of their environmental benefits. Ignoring the contributions of state-supported resources forces state customers to rely on capacity from resources that do not earn revenue from state policies, essentially requiring state customers to procure a fixed amount of capacity from natural gas and coal-fired power plants. Reversing the state's choice of generation mix in this manner “necessarily affects” the “construction” or retention of particular types of resources (those not receiving revenues pursuant to state policies targeted by PJM), and is exactly the sort of “direct regulation of generation facilities” that the U.S. Court of Appeals for the D.C. Circuit stated the Commission would not engage in when approving the Commission's authority to create capacity markets.

The manner in which MOPR-Ex would inappropriately strong-arm states to modify their environmental regulations is illustrated by the proposal's clumsy “RPS Exemption,” which imposes a raft of restrictive requirements on state programs in order for revenues under those policies to be permitted to influence outcomes in the PJM capacity market. In practice, the RPS Exemption would coerce states into adopting programs that comply with the conditions necessary to qualify for the exemption. The criteria of PJM’s proposed RPS exemption are expansive, and many of them lie at the heart of state environmental policy decisions. The exemption appears not to include state
policies that target particular resource types such as offshore wind, as well as state policies that differentiate between new and existing resources. At the same time, it dictates specific terms by which competition for renewable energy certificates must occur for RPS programs to be eligible. In doing so, PJM would effectively regulate the sales of RECs, despite the Commission's clear statement that the sales of unbundled credits lies beyond the Commission's jurisdiction. Defining what resource types are "renewable", for example, is a core environmental policy decision states face in designing renewable portfolio standards. Different resources have different types of benefits that states may want to encourage.

Consistent with their environmental policymaking authority, states need not classify resources as either "renewable" or not "renewable" in a binary fashion. Indeed, many states have adopted resource-specific carve outs as part of broader renewable portfolio standard policies, a policy decision that appears to be frustrated under PJM's MOPR-Ex proposal. That PJM and the Independent Market Monitor appear to see renewable resources only through the lens of emissions avoided is indicative of their lack of experience with environmental policymaking, and demonstrates the inappropriateness of placing them in that role.

See [PJM filing, Attachment DD, at proposed tariff § 5.14(h)(10)(b)(ii).]

See [Id. at 5.14(h)(10)(b)(iii)-(iv).]

The Commission holds that "an unbundled REC transaction that is independent of a wholesale electric energy transaction does not fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA." [WSPP Inc., 139 FERC ¶ 61061 at P 24 (Apr. 20, 2012)]. An "unbundled REC transaction does not affect wholesale electricity rates, and the charge for the unbundled RECs is not a charge in connection with a wholesale sale of electricity." [Id.]

See supra Background section I.A.

See id. (describing the state policies at issue); infra Appendix A (explaining how this policy option appears to be frustrated by MOPR-Ex).
Indeed, even with regard to the narrower environmental objective of regulating carbon emissions, PJM recognizes that its "theoretical ideal market approach" of an "objective embedded in the wholesale market clearing mechanism" may be practically impossible to achieve given the "daunting number of practical, legal, and political obstacles" such an approach would face.

Regulating emissions is a complicated business. States must control for leakage, potential resource shuffling, and other issues.

Deciding whether to credit only new or both new and existing resources is part and parcel of this decision, as states face a tradeoff between ensuring that sales of the credit cause additional emission reductions beyond the status quo, and the ability to foster a liquid market for credits.

While the Commission can certainly approve of RTO rules that facilitate state policy approaches to addressing this complex array of issues in an

182 PJM filing at 54-55.

183 See James Bushnell et al., Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction, 23 R EV.

184 States may opt to credit existing and new resources or only new resources based on their determination of what will drive additional emissions reductions at least cost. See, e.g., N.Y. Pub. Serv. Comm'n, Case 15-E-0302, Order Adopting a Clean Energy Standard, at 14-17, 78, 115-16 (Aug. 1, 2016) (providing separate crediting mechanisms for existing and new resources based on cost considerations, additionality, and other factors), available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b44C5D5B8-14C3-4F32-8399-F5487D6D8FE8%7d

A regulation targeting new resources has the advantage that it is tied to measurable progress to reduce emissions. As Bushnell explains with regard to the analogous low-carbon fuel standard, which like a more indirect credit for all renewables, would "have no impact" if the amount of demand set by the state "is less than the existing supply" of the underlying product. Bushnell et al., at 184.
efficient manner, it may not frustrate state policy approaches by essentially making decisions about these tradeoffs itself. Applying a MOPR that blocks capacity market sales from resources supported by a state RPS program where that policy draws a distinction between existing and new resources is exactly the sort of second-guessing of state regulators' environmental policy decisions that is beyond the Commission's proper role. MOPR-Ex's many arbitrary carve-outs and exemptions likewise illustrate the unworkable and inappropriate nature of allowing RTOs to pick and choose which resources may fulfill the region's capacity obligations. Unlike the unelected officials at PJM and the Independent Market Monitor, who are accountable only to the PJM market participants, state policymakers can be voted out of office if their residents conclude that RPS programs or other environmental policies are poorly designed.

C. PJM's short-sighted contention that state policies threaten its capacity market paradoxically sets the market on a path toward greater conflict and uncertainty while ignoring real market problems that could be addressed. PJM's mistaken focus on the supposedly "adverse" effects of state policies ignores the real challenge facing the capacity market: its structure is ill suited to facilitating the types of resources that states want and need. PJM's approach will lead to increased conflict and uncertainty over time. Focusing on market revisions that facilitate rather than frustrate state policy choices will yield more efficient outcomes. Rather than seeking to neutralize state policy choices, PJM should examine capacity market revisions, such as a seasonal market construct, that make the market more compatible with state policies. Adopting either of PJM's proposed options will create more uncertainty and conflict over time because PJM's focus on potential "price-suppressive effect" provides no principled limit to the scope of Commission intervention. As states continue to adopt policies affecting the
For capacity repricing, the counterfactual scenario of what prices would be without state policies will become increasingly extreme, imposing larger and larger unnecessary costs upon consumers over time. For MOPR-Ex, the amount of redundant capacity supported by customers year after year will continue to increase. Eventually, the unnecessary costs imposed upon customers will become untenable and a massive course correction will be necessary. The inevitable unworkability of this framework will thus cause greater uncertainty than the purported problem PJM aims to cure.

MOPR-Ex could yield particularly inefficient policy outcomes because in addition to increasing redundant capacity, mitigation of state policies would likely push states to achieve their goals through less efficient policy solutions. RPS programs and zero emissions credit policies are transparent in their aim to price environmental benefits. RPS programs, in particular, rely on competitive procurement, ensuring that climate goals are met through relatively transparent and efficient means. Were MOPR-Ex to be adopted, states could avoid mitigation by adopting less transparent and less efficient policies, relying more on siting, tax code, and other policy levers. Neither the market nor the public interests would be served should states be forced to rely on a narrower band of market interventions to achieve the same results.

By contrast, capacity market revisions or other actions taken by the Commission could reduce the need for state intervention in the market, increasing market efficiency. For example, as a Brattle Group report explained, "the current PJM capacity market design maintains several shortcomings that limit the full participation of seasonal capacity resources to more cost-effectively meet seasonal reliability needs." As much as 6000 MW of summer-only supply may...
be excluded from the market, due to barriers caused by the market construct. Indeed, even as planned solar installations have grown in the region, solar offers decreased 63 percent between the last two auctions (2019/20 BRA and 2020/21 BRA), starkly demonstrating how market design can deter participation.

More generally, while PJM's markets have facilitated the construction of a large number of new natural gas turbines, they provide a bad fit for other types of resources. Because gas resources are frequently marginal in the energy market, over the long-term energy prices are correlated with gas prices. This provides a natural price hedge for gas resources, while other fuel-based resources are subjected to much higher risk.

Resources that have relatively higher upfront capital costs and no fuel costs receive no hedge at all and are forced to procure hedges to insulate against fluctuations in the price of gas.

Further, PJM's capacity market demand curves are set based on a generic natural gas unit, meaning that net CONE is pegged to the amount of revenues necessary to induce natural gas plant construction, not construction of resources of other technology types. Importantly, the advantages gas resources enjoy—a price hedge and capacity market revenue specifically designed to cover the amount of upfront capital needed to 186

See Guo et al., The natural hedge of a gas-fired power plant (Feb. 20, 2014), available at https://link.springer.com/content/pdf/10.1007/s10287-014-0222-x.pdf. Gas resources' natural price hedge is demonstrated through an examination of the 'spark', 'dark' and 'quark' spreads in PJM, which show the differences between market prices and the cost of gas, coal, and nuclear fuel, respectively. The market monitor's 2017 State of the Market report shows much higher volatility year-to-year for quark and dark spreads than the amount of volatility year-to-year in the spark spread. See Monitoring Analytics, LLC, Vol 2: 2017 State of the Market Report for PJM, at 312 (March 8, 2018).

187 PJM itself acknowledges the challenge of longer term hedging in the RPM, explaining, "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." Resource Investment Whitepaper at 28.
construct—are due to PJM’s market structure, not an inherent benefit of the resource. All else equal, customers would prefer price certainty provided by resources that do not rely on fuel.

Short-term marginal cost-based markets shift the risk of changing fuel prices onto suppliers who do not face fuel costs, and more importantly, onto customers.

Given PJM’s market structure, it should be no surprise that (except for resources facilitated by RPS programs and other state policies) virtually all new construction financed on a merchant basis in the region has been gas-fired.

Gas-fired resources have relatively low upfront capital costs, and have an advantage in capacity markets, where they can offer a lower price with the knowledge that they will be able to recover a large share of fixed costs with high certainty through their low-volatility spread between energy prices and fuel costs.

But the massive boom in gas-fired resources in the PJM region imposes a large fuel price risk on consumers, while simultaneously setting the power sector on course to create massive amounts of emissions, pollution, and other environmental impacts caused by the natural gas supply chain in a manner that is at odds with state climate and environmental goals.

Many states justifiably are not pleased with this market outcome and are seeking to modify the generation mix through environmental policies and other state regulations. Yet the very best policy options to reduce the fuel-price risk that consumers face are precisely what
PJM’s proposals (and particularly the MOPR-Ex option) frustrate. State-facilitated long-term power purchase agreements between load serving entities and renewables resources with no fuel costs leave less energy that is vulnerable to the swings of PJM’s high fuel-price risk energy market.

Long-term contracts also have the added advantage of making financing for capital-intensive assets cheaper, further reducing the costs and risks for customers. But MOPR-Ex would block capacity market access for resources supported by these contracts, and capacity repricing would adjust market prices upward in response to them.

Rather than modifying its market to be more at odds with state policies, PJM should instead consider how it can help states achieve the resource mixes that they desire at lower cost. Such a focus could yield policy prescriptions that benefit both customers and suppliers. For example, while states may want to encourage utilities to financially hedge against fuel risks using futures and swaps, that is currently challenging to accomplish given the illiquid market for long-term hedging products. PJM should consider ways to facilitate a more liquid market. PJM could also consider how to facilitate long-term power purchase agreements at lower cost, better incorporating such agreements into its market design or even providing a market platform by which such transactions may occur.

In summary, while state policies affecting PJM market prices is not a problem, there are things PJM can do to provide a market that better facilitates state policy choices. Focusing on those areas would increase market efficiency and benefit customers rather than saddling them with unnecessary costs.

PJM is wrong in suggesting that such state contracts “shift risk from private capital to customers.” PJM filing at 46. Where states procure new renewable resources through a competitive process awarding long-term contracts, that lowers the overall cost while simultaneously reducing risk for both suppliers and customers by providing both with long-term price certainty.
II. Threshold legal and procedural flaws bar the Commission from approving any of the proposed PJM proposals

Multiple, central deficiencies in PJM's filing render it inconsistent with the requirements of the Federal Power Act, and the Commission should summarily reject it.

A. PJM filed a set of poorly developed proposals flouting the principle of stakeholder engagement

In this filing, PJM ignores the definitive preference of its stakeholders to maintain the status quo and avoid changes to the capacity market structure to account for the impacts of state policies. Despite that clear preference, ample evidence that PJM is oversupplied with capacity, and the fact that its capacity market is structured to provide more than adequate resource supply under the status quo model, PJM now asserts that "[d]oing nothing . . . is not an option." 191

Although PJM retains the ability to propose changes to its capacity market rules absent stakeholder endorsement, the Commission has previously recognized that "stakeholder consensus is an important factor to consider in reviewing the justness and reasonableness of a rate design." 192

Broad stakeholder support is particularly relevant on issues, like the one presented here, where the Commission must balance the conflicting interests of different constituencies. 193

A lack of broad stakeholder support for the two proposals offered here also means that critical elements of those proposals were not subjected to the kind of stakeholder scrutiny that a proposal with stakeholder buy-in would undergo.

191 PJM filing at 17.
Just as "stakeholder support alone cannot ultimately prove that a rate design is just and reasonable," stakeholder disapproval of a pending proposal does not demonstrate that it is unjust and unreasonable. However, the lack of stakeholder support weighs against approval of either capacity repricing or MOPR-Ex because it demonstrates that neither proposal achieves an acceptable balance of the interests of states, generators, consumers, transmission owners, and other interests. In this case, as described below, the majority of the stakeholders are correctly skeptical of both proposals because neither is just and reasonable, and both would arbitrarily distort market prices and inflict serious harms upon consumers.

PJM's rejection of its stakeholders' preference for the status quo in these circumstances undermines the role the stakeholder process has long played in vetting potential changes to market rules. Engaging stakeholders in an exhaustive process, which provided PJM with every opportunity to convince those parties that inaction was "not an option," and then ignoring the outcome of that process undermines confidence in the process itself.

Knowing there is a high likelihood that their preferences will be disregarded, stakeholders will logically dedicate fewer resources to these discussions, resulting in less-informed decisions. Even PJM has acknowledged that its stakeholder process has become less effective, announcing in a recent letter that another emerging issue provides an opportunity "for the stakeholder community to come together and demonstrate that the PJM stakeholder process can deliver thoughtful and timely consensus."
While issues of RTO governance are properly addressed in a stand-alone proceeding designed to explore those issues, the Commission should be mindful that approval of RTO proposals made without stakeholder endorsement could exacerbate the lack of trust in those processes that are so critical in ensuring that high-quality proposals are offered for the Commission's consideration.

B. PJM's filing is deficient under section 205 of the Federal Power Act

PJM attempts to evade the requirements of the section 205 of the FPA and NRG Power Marketing, LLC v. FERC, by filing an ambiguous and multi-faceted proposal with the Commission and inviting it to choose a path forward. This endeavor to disguise a section 206 proposal under section 205 cloth is as transparent as it is unavailing. While PJM claims that it is making its filing under section 205, this self-serving characterization is inaccurate. PJM's filing fails to meet the requirements of section 205 and should therefore be rejected outright, or at minimum be characterized as a filing under section 206 of the FPA (which would also compel rejection of the filing given PJM's failure to explain or even state that its current tariff is not just and reasonable).

Section 205 sets a lower bar for Commission approval than section 206, so along with that easier-to-meet standard come certain requirements and limitations on the Commission's...
Under section 205, "FERC must accept proposed rate changes . . . so long as the changes are just and reasonable.

In contrast, under section 206, FERC must find the current rate unjust and unreasonable and the proposed rate just and reasonable: "It is the Commission's job—not the petitioner's—to find a just and reasonable rate.

Section 205 restricts FERC to a "passive and reactive role" in reviewing the proposed rate, as opposed to its more active role under section 206.

Further, to be properly filed under section 205, a tariff revision must "plainly" state the change sought, be sufficiently definite to take effect by operation of law, and provide adequate notice to consumers.

Here, PJM has asked FERC to go far beyond a "passive and reactive role" and to choose among a variety of competing multi-faceted proposals, which it invites the Commission to combine or deconstruct and reassemble in a manner that raises countless possible outcomes.

PJM's vague proposal fails to provide customers with adequate notice, and could not possibly become effective without further guidance from the Commission. While PJM indicates that it would consent to various responses from the Commission, this attempt to circumvent section 205 does not cure its proposal's failure under that section.

Id. at 113 (emphasizing the function section 205 requirements serve to protect utility customers).

Id.

Maryland Public Service Comm'n v. FERC, 632 F.3d 1283, 1285 n.1 (D.C. Cir. 2011).

NRG Power Marketing, LLC, 862 F.3d at 114 (quoting Advanced Energy Management Alliance v. FERC, 860 F.3d 656, 662 (D.C. Cir. 2017) (internal quotation mark omitted)). See also City of Winnfield, La. v. FERC, 744 F.2d 871, 875-76 (D.C. Cir. 1984).

City of Winnfield, 744 F.2d at 876.


Id.

See PJM filing at 5-7 (proposing further resolution of the proposals' details through additional process).
PJM's "jump ball" is more accurately described as "jump balls." "Jump ball" implies that there are two competing proposals. While even that would be problematic, PJM's proposal actually offers a multitude of options. Capacity repricing is one option, and under the broader heading of MOPR-Ex, PJM raises two more different alternatives. One has an exemption for renewable portfolio standards. The other does not.

Then, there are untold permutations among those three options on which utility customers have received no conceivable notice. PJM has invited the Commission to send the matter to a settlement judge for resolution if there is an undefined "subset of issues" that require acceptance "subject to suspension and further proceedings."

Indeed, a February 16, 2018 letter from Andrew L. Ott, the President and CEO of PJM, demonstrates PJM's desire to file an intentionally ambiguous proposal that places the Commission in its section 206 role of proactively designing the rate that will take effect rather than its "passive and reactive" section 205 stance. Mr. Ott stated that because the choice among policy options involves "a balancing of federal and state interests," the PJM Board "concluded that this question should fall to the Commission as the federal policymaker not to the PJM Board."

Mr. Ott's letter even contemplates continuing stakeholder engagement at the Commission after FERC makes a policy call through the use of "a time-bound settlement judge proceeding, with expectation that such a process will bring refinement, compromise and more"
consensus support for what ultimately will be presented to the Commission later this year as a package of proposed rule changes."

In presenting this confusing mix of adjustable options and inviting the Commission to send the matter to a settlement judge to modify them in an unspecified manner, PJM’s proposal fails to provide adequate notice to utility customers. It fails to "plainly" state the changes to be made to any rate, charge, or service, such that customers "do not have adequate notice of the proposed rate changes or an adequate opportunity to comment on the proposed changes."

Section 205’s requirement to "plainly" state the changes to be filed is legally crucial not only for its notice-serving function, but also because specificity is required to indicate what the proposed rate will be that takes effect in 60 days by operation of law should the Commission not act. Here, there is no sufficiently plain or definite rate such that this could happen, because while PJM has expressed a preference for capacity repricing, it has also proposed other options that it asserts are just and reasonable. If FERC fails to act within 60 days, which capacity construct would take effect by operation of law? This ambiguity in and of itself betrays PJM’s assertion that it is making a section 205 filing.

Nor does PJM’s attempt to confer before-the-fact consent on FERC cure its violation of section 205’s requirements. Just as PJM’s after-the-fact consent to a non-minor modification by FERC of a proposed rate failed to provide adequate notice to consumers in NRG Power Marketing, LLC, so too does before-the-fact consent to FERC choosing among a multitude of non-minor and dramatically disparate options. Taken to its logical extreme, PJM could file a

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210 Id.
212 NRG Power Marketing, LLC, 862 F.3d at 116 (citing City of Winnfield, 744 F.2d at 876).
213 Id.
214 NRG Power Marketing, LLC, 862 F.3d at 116-17.
blank piece of paper with FERC entitled "Capacity Market" and advise FERC that it would accept any construct FERC devised. The law, however, requires more than that. Under section 205, a utility cannot provide a blank check to FERC or even one that is partially filled in. If a utility wishes to do that, it must file a complaint under section 206, after which time "[i]t is the Commission's job—not the petitioner's—to find a just and reasonable rate."

PJM's attempt to rely on past Commission orders in which a utility presented the Commission with two or three options under section 205 of the FPA or section 4 of the Natural Gas Act is unavailing. Each of the orders cited by PJM preceded NRG Power Marketing, LLC, when the law was less clear on the Commission's role in reviewing a proposed rate and whether the Commission could approve a rate subject to conditions that the utility could accept or reject. Moreover, in each of the orders cited by PJM, no party appears to have objected to the fact that options were presented to the Commission. Nor, apparently, was there an open-ended invitation to the Commission to submit the matter to a settlement judge for resolution of an undefined and potentially boundless "subset of issues" relating to the proposed rate. Finally, none of the orders choose or modify a market design on a matter that involves billions of dollars. Instead, the orders address far more limited resource-specific issues (such as cost recovery), not the structure of the market itself. Far from supporting PJM's request, a comparison of the orders and PJM's filing underscores the unprecedented nature of PJM's request under section 205.

There is a subtle but pernicious aspect to PJM's filing a number of disparate proposals under section 205. By doing so, in effect, PJM has deployed a "divide and conquer" strategy in which stakeholders may opt for one design over others as the lesser evil among them. This may give the Commission the misleading impression that there is more support for a design than actually exists. If each proposal were considered separately – as happened in the PJM stakeholder process itself and as should properly
Because PJM's filing has failed to meet the requirements of section 205, it should be rejected. Even if it is not rejected, it can only be properly considered under section 206. Under section 206, PJM's jump ball fails because PJM has not shown that its current rules are unjust and unreasonable. While PJM has asserted that there is a "gap" in its rules with respect to revenues earned pursuant to state policies, this assertion, without more, is insufficient to meet its burden under section 206 of the FPA. Nowhere in its 600-page filing has PJM alleged that its current capacity construct is unjust and unreasonable. It must therefore be rejected.

C. PJM fails to meet its threshold burden to offer a clear rationale for its proposals and substantial evidence to back that rationale

Even if the Commission improperly proceeds to consider PJM's proposals under section 205 of the Federal Power Act, PJM has also failed to meet its burden under that standard. "Section 205 places the burden of proof on the public utility to show that its proposed tariff change is just and reasonable and not unduly discriminatory or preferential." The Commission requires substantial evidence demonstrating that the statutory standard is met. PJM does not meet this threshold task. At the bare minimum, PJM must clearly articulate a rational theory by which its market design is just and reasonable and not unduly discriminatory or preferential. No such clear rationale is presented in PJM's filing. As best we can understand it, PJM's theory is that any of its proposals are just and reasonable because they address the price-suppressive effects from state actions that pose a concern to market outcomes. But it never happen under section 205 – there would be a clearer indication of the extent of the opposition.

18 C.F.R. § 35.5 (requiring the Secretary of the Commission to reject deficient filings).

PJM filing at 18.


Id.
clearly explains what that category of state actions are, and why those actions pose a threat that is different in kind or scope from others that are not the target of the proposals. Even PJM admits that some price-suppressive effect is "workable." So what are those lines, and are those distinctions backed by evidence? The answer to the first question is impossible to divine from PJM's filing, and the answer to the second is clearly no. PJM offers a range of different theories, none backed by any clear logic or evidence.

For example, PJM suggests that the harm to market outcomes comes from "programs which target large-scale, unit specific resources." Yet PJM never explains why these programs would be different in terms of their market effects from, for example, price supports that are provided to an entire category of resources at large magnitudes.

Nor does PJM articulate, even loosely, what its benchmark is for a "workable" level of impact on the market. Even if it had, PJM's proposals do not even target programs that focus on large-scale, unit-specific resources; both PJM's proposals largely capture many small-scale resources that are not recipients of "unit specific" support, while excluding others state actions that do target large-scale, unit-specific resources.

PJM's explanation is not internally consistent, much less backed by substantial evidence.
PJM offers analysis that purports to show that the programs targeted would impact revenues for sellers of tens of thousands of megawatts of capacity in PJM.

We show below that this analysis is based on fundamentally flawed assumptions. Its conclusions are therefore unsound, and it cannot provide a reasoned basis for the proposal.

But even assuming the analysis is valid, the lessons it offers contradict PJM's own logic for focusing on some state programs and not others. All PJM's analyst claims to show is that when a certain large quantity of capacity with zero offers is added to the market and the auction is run again (without allowing the market to adjust), price goes down.

And it goes down more if there are more megawatts of zero offers. But if that effect is sufficient under PJM's theory to intervene, then the cumulative total capacity affected by government actions should matter as much or more than whether any one program is targeted to a specific unit or not—because all that matters is the total megawatts of capacity that is offering at zero. Following PJM's logic, there is no reason at all to ignore zero offers from one quarter of the capacity in the market (i.e., the traditionally regulated share of capacity) while focusing on zero offers from five percent of the capacity in the market (i.e., renewables). Yet that is exactly what PJM proposes to do.

The failure to offer up a rationale for its proposals is particularly glaring with respect to its targeting of demand response and price-responsive demand policies. Though they comprise nearly a third of the capacity that PJM expects to immediately target under its proposals, PJM never even describes what these programs are or why they should be targeted. The record is

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228 PJM filing at 16 (discussing the Keech Affidavit conclusions).
229 See infra Argument section III.C.3.
230 PJM filing, Keech Affidavit at PP 6-8.
231 Id. at P 18.
barren of even a token explanation of PJM's belief that these programs pose meaningful concerns of price suppression.

D. PJM relies on the wrong legal standard and thereby fails to provide the record necessary to approve the proposals. As a final threshold legal flaw, PJM cannot demonstrate its proposals are just and reasonable because PJM relies on a standard that lacks a basis in longstanding Commission precedent and that would leave consumers without statutory protection. By focusing on the wrong, investor-focused standard, PJM fails to address how its proposals will impact wholesale customers and thereby denies the Commission the record it requires to evaluate whether the approach is just and reasonable. PJM's reliance on a standard that is skewed toward generator interests obscures the fact that all of PJM's proposal are a bad deal for consumers, hiking prices for no value. Yet failing to provide the relevant information the Commission needs to assess the proposal alone is sufficient grounds to reject the filing.

PJM points to the Commission's recent novel articulation of the "first principles" of the capacity markets in its recent order approving ISO New England's new capacity market construct. It argues that the RPM cannot continue to advance these so-called "first principles" in the face of state policy actions. PJM makes achievement of these new principles a core benchmark for approval of its proposals, structuring its argument and evidence against that.

Similarly, PJM fails to include any discussion at all of the relation between its proposal and energy storage policies. This contributes to the proposal's failure to meet section 205's requirements, as discussed in Argument section II.B, and to the extent PJM's proposal does affect energy storage policies, it constitutes a failure to provide substantial evidence.

Maryland People's Counsel v. FERC, 761 F.2d 780, 786 (D.C. Cir. 1985) (remanding for failure to consider "highly relevant factors" related to an order's impacts on consumers).

Fatally, however, much like the Commission's reliance on these principles in the CASPR Order, PJM boils these principles down to a test of investor expectations. For example, PJM points to the market's ability to enable private equity investment as a key marker that market rules are just and reasonable.

Indeed, "investor confidence" sufficient to ensure resource adequacy at just and reasonable rates is the "ultimate goal."

As such, while PJM acknowledges that consumer interests are one parameter to consider in evaluating a capacity market design, PJM frames those interests very narrowly and in terms of whether the market is stimulating enough of a certain kind of investment.

The slim explanation PJM offers the Commission on the impacts of its proposals to customer interests is the unsubstantiated claim that subsidies insulate suppliers from financial risk at the expense of customers.

The claim is factually incorrect with respect to the state renewable portfolio standards and demand response programs PJM targets, and also demonstrates the inadequacy of PJM's framing of consumer interests. PJM is silent on how wholesale customers are directly affected by the two proposals. Instead, PJM's articulation of the benefits to consumers is nothing more than that the PJM proposals will insulate certain investor expectations from being thwarted by the regulatory risks of some public policies.
formulation, it is enough for the Commission to know that the market will give investors the confidence they need to profit through the merchant generation business, because thriving merchant generation means "[r]isks that were traditionally borne by customers have been shifted to investors."

In other words, because the shift from traditionally regulated, vertically integrated utilities to competitive markets has indeed brought wholesale customers benefits, PJM's standard dictates that it is enough to incant that 'more competition is better' to address the consumers impacts of a proposal.

PJM is wrong that investor confidence can serve as a proxy for consumer interests in FERC's determination of whether a rate is just and reasonable. The Commission cannot so neglect its "primary aim" to protect consumers "from excessive rates and charges."

Such "protection of the public interest" must be clearly "distinguished from the private interests of the utilities.""
recognize this truth—and the Commission has never held as such. Nor can examining a single factor, whether investment in merchant generation will thrive under a capacity construct, sufficiently account for the consumer impacts of a proposed market construct. The Commission's long-standing interpretation of the FPA entails consideration of the inherent trade-offs across consumer and supply interests in determining whether a rate is just and reasonable, and does not permit such shortcuts.

In fact, each of PJM's proposals presents a classic case where confidence for investors in supply resources will not translate into customer benefits. As explained in Argument section III.C.1, capacity repricing increases supplier profits while structuring competition in a manner that does not benefit customers, while MOPR-Ex benefits suppliers by channeling customer dollars toward unnecessary redundant capacity. In simply assuming that what is good for suppliers is good for customers, PJM has failed to put forward the record necessary to conduct its vital task of balancing consumer and supplier interests.

Of course, whether prices provide adequate signals to invest in new capacity when such capacity is needed is an important factor in the Commission's balancing test. It has never, however, been an exclusive factor that overrides the need to consider other factors and their impacts on consumer and supply interests.


Promoting Transmission Investment through Pricing Reform, 116 FERC ¶ 61,057 at P 21 (July 20, 2006), reh'g granted in part by 117 FERC ¶ 61,345 (Dec. 22, 2006), decision clarified on denial of reh'g by 119 FERC ¶ 61,062 (Apr. 19, 2007) ("The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests. It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our polices must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives."); New York Indep. Sys. Operator, Inc., 122 FERC ¶ 61,064 at P 54 (Jan. 29, 2008), order on reh'g, 125 FERC ¶ 61,299 (Dec. 18, 2008) (rejecting use of updated demand curve factors that "do not recognize the need to balance the impact on consumers with the need to provide correct price signals for new generation entry").
III. PJM's proposals both fail to meet the standard for the Commission to approve the filing under section 205 of the Federal Power Act

A. Even under PJM's own flawed standard, PJM's proposals fail on each count. Even assuming that PJM's flawed investor-focused standard adequately protected customers, PJM's proposals do not perform well against the CASPR Order's capacity market principles. As discussed at length over the next sections, there is insufficient basis to conclude that either repricing or MOPR-Ex will in fact facilitate robust competition; provide the right price signals; result in selection of least-cost set of resources; ensure price transparency; shift risk from customers; or mitigate market power. PJM's proposals add unnecessary complexity to the capacity market construct, adding in a layer of unworkable administrative judgment about "what is a subsidy" that will cloud market certainty, lead to arbitrariness in price signals, and obscure price mechanics. The arbitrariness of determining which regulatory risks incumbent investors must be protected from, and which ignored, does nothing to shift risk away from consumers or enhance competition in the markets. Rather, it is simply another form of shifting who the winners and losers are, but based on PJM's line-drawing. Absent any principled economic rationale underpinning either market construct, PJM's proposals work to the benefit of certain competitors instead of competition.

In short, even under PJM's deeply flawed standard, the Commission must reject PJM's proposal as unjust and unreasonable.

B. At its core, PJM's proposals are based on arbitrary line-drawing, which results in undue discrimination against certain buyers and sellers. The core to each of PJM's proposals is the definition of an "actionable subsidy," which is the basis for application of both capacity repricing and MOPR-Ex. PJM claims that it targets

See Gramlich Affidavit at section IV.
This is false. PJM incorporates no criteria to link the targeting of state policies to any actual effect on the market. PJM instead uses a proxy, revenue-based measure for market impact that even it admits will affect capacity offers that have no market effect.

At the same time that it claims to be focused on policies that pose “legitimate price suppression concerns,” PJM ignores or exempts other state policies that cumulatively provide billions of dollars in incentives for resources that participate in the RPM. The defining feature of PJM’s proposals—drawing a line to define a “subsidy” that supposedly threatens the capacity market—is so arbitrary and riddled with inconsistencies as to be meaningless. The arbitrary nature of PJM’s proposal results in direct harm to wholesale customers and, under MOPR-Ex, capacity sellers. PJM’s Repricing Proposal arbitrarily subjects some customers, those located within Load Deliverability areas (“LDAs” or “capacity zones”) where resources are deemed to be subject to “actionable subsidies,” to higher prices even though these customers are no different than customers located outside of that LDA. In each case, resources located within the customer’s service area are benefiting from state policies and pose the same hypothetical threat to capacity market prices. Yet under PJM’s proposal, customers in one area face significantly higher wholesale capacity prices than the other set of customers. Similarly, MOPR-Ex arbitrarily forces some customers to pay for unneeded capacity (ostensibly, to mitigate the price-suppressive effects of a targeted policy) while others, who are equally affected by a state policy that has the same theoretical market effect but is not deemed “actionable,” are not. PJM’s proposal is a textbook case of undue discrimination against certain consumers.

250 PJM filing at 69 (“To identify only those resources receiving a subsidy that warrants action based on design or market impact . . . .”).

251 See infra n. 259 (citing Giacomoni Affidavit).

252 Id. at 70.
imposing excessive, discriminatory costs that will easily range in the billions of dollars per year.

While PJM makes ensuring investor confidence the key touchstone of its proposals, its arbitrary definition of a subsidy results in uneven treatment among investors. Under MOPR-Ex, market participants who have based their investments on the expectation of the regular application of certain state laws (such as the longstanding RPS programs) lose out; while at the same time other investors who have relied on state policies that are not deemed actionable but have the same potential market effects (Kentucky coal incentives or Pennsylvania development zones) do not. To the extent investor expectations are a rightful subject of the Commission’s just and reasonable standard at all, PJM’s proposal results in exactly the unduly discriminatory application of the standard that is prohibited under the Federal Power Act.

1. PJM’s definition of “actionable subsidy” is arbitrary

While historic versions of the MOPR were in fact triggered by projected impacts on the clearing price, PJM elected not to base its definition of an “actionable subsidy” on the market effects of a state policy. Instead, PJM’s definition of an “actionable subsidy” under both proposals deems any form of support to a resource that exceeds one percent of its projected

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See e.g., PJM 2007 RPM Settlement Rehearing Order PP 170-171.

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Including, “material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource” or “other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource.”

See proposed PJM Tariff § 1, Definitions L-M-N (Option A). Note that the
annual revenues from PJM markets "material."
PJM argues that this definition reflects that "not every subsidy impacts the seller's offer to a degree that materially affects it offer price," suggesting that the one percent revenue trigger is a threshold for revenue that will impact a market participant's offer behavior.
PJM also claims that this threshold is meant to target subsidies that affect market clearing prices, stating that its definition "ensure[s] that only those generation resources that receive a subsidy that warrant action based on design or market impact" qualify.
But PJM offers no evidence or reasoning on either point. It is not at all clear, for example, that support that is a little less than one percent of the revenue of each resource would not affect offer behavior, but support that is a little more than one percent of revenue will. Or, accordingly, that the former (just under one percent) will not affect market outcomes, but the latter (just over one percent) will. This is particularly true if one imagines that the first program benefits tens of thousands of megawatts at a cumulative value of billions of dollars, but the second affects only a few thousand megawatts and at a much lower total dollar value.
A subsidy of just under one percent of a 1000 MW resource's offer price, for instance, is nearly 50 times greater in magnitude than a subsidy of just over one percent a 20 MW resource. If either resource would have cleared in the capacity market with the subsidy but fails to clear without, the smaller subsidy on the larger resource would far outweigh the smaller one in terms of market impact. PJM's decision to focus on relative value of support to the resource (rather than definition of an Actionable Subsidy "generally mirrors that PJM is proposing under Capacity Repricing.") PJM filing at 100.
PJM filing at 74 (citing proposed PJM Tariff, Attachment DD § 5.14(j)(2)(d) (Option A)). PJM incorporates two other size thresholds into its Repricing Proposal. Five thousand MWs of actionable subsidy must enter the entire PJM market, or greater than or equal to 3.5% of a given LDA reliability requirement, before Repricing is triggered. PJM describes this as a "transition mechanism" to provide the market time to adjust to new rules.
Id at 92.
than to the market) systematically favors larger resources, who are able to receive subsidies far larger in magnitude than those received by smaller resources without being mitigated.

PJM's own testimony contradicts the notion that the size of a subsidy is determinative of whether an offer from a resource materially affects the market. As Mr. Giacomoni, PJM's declarant, describes, "the size of the subsidy does not, by itself dictate whether a resource would be economic in PJM's market . . . .[d]epending on the resource's costs, and the revenue the resource receives in the PJM energy and ancillary service markets, the subsidy payments could effectively be surplus."

In other words, PJM's revenue threshold will capture and reprice resources that are economic and whose offers, even by PJM's judgment, are therefore not price-suppressive.

Moreover, as scholars from the Institute for Policy Integrity make clear, simply affecting an offer does not necessarily equate to an effect on clearing prices:

Any decrease in the bid of an infra-marginal unit that would have cleared the auction anyway, all else equal, would not affect the market clearing price. Thus, externality payments can affect the auction price only in limited situations: (1) when they induce entry (or prevent exit), increasing available supply of capacity, and hence lowering the market clearing price; or (2) when they directly lower the marginal bid, and hence the market clearing price.

Thus, the proposals do not actually target "market impacts" or "price-suppression" as PJM claims, though PJM stakes the reasonableness of its policies on the ability to evade those effects.

2. PJM carves out exceptions for policies that undeniably would have the same effect on market participant behavior and investor expectations.

PJM contends that its definition of an "actionable subsidy" is calibrated to target policies with price-suppressive effect. Yet it adopts a grab bag of justifications in determining which

259 PJM filing, Giacomoni Affidavit at P 36.
260 IPI report at 15.
While PJM claims that it aims to exclude "the types of resources that are not likely to raise price suppression concerns," even a superficial consideration of the exemptions show that not to be the case.

PJM proposes to allow self-supply to participate unmitigated into the capacity market, without the previously applicable net short and net long thresholds, because "new entry offers from this class of sellers is only a very small slice of RPM offers."

PJM also claims that vertically-integrated utilities are unlikely to rely on price suppression as a strategy to benefit the non-self-supply portion of their portfolio (i.e., that these entities lack incentive to exercise market buyer power).

PJM offers no explanation for its "general industrial development" exception, other than that it had previously been a part of the MOPR.

Each of these reasons would provide equal basis to exempt resources supported by an RPS program. Solar resources, for example, comprise a smaller share of capacity clearing in recent BRAs than capacity relying on the self-supply exemption.

Renewable resources have long been recognized to be "a poor choice if a developer's primary..."
The purpose is to suppress capacity market prices. And renewable's exemption from the MOPR was approved by the Commission well before these other exemptions. PJM's rationale for exempting some categories of resources and not others is manifestly arbitrary. And closer examination only reveals more problematic inconsistencies between PJM's stated goals of the proposals and the scope of the policies it targets. Clean Energy Advocates demonstrate in this section that PJM ignores policies that meet its own definition of a subsidy likely to have a material impact on the market. We do so, not so as to eliminate the exemptions PJM has set forth, but rather to point out the deep and incurable flaws in PJM's approach and the inherent unworkability of mitigation rules that aim to eliminate the effects of "material" government preference from the markets. Moreover, as explained later in the section, PJM's arbitrary line-drawing would have serious impact, imposing undue discriminatory harms to some customers and suppliers.

In its filing, PJM describes the self-supply exemption as applying to resources "owned or controlled by entities with long-standing business models for capacity procurement, which do not raise concerns of possible price suppressive intent (e.g., certain vertically integrated, cooperative, and municipal utilities.)." In its Resource Investment Whitepaper cited for other purposes in its filing, PJM called out the excesses of these same long-standing business models. "Regulated models," explains PJM, "do show a tendency . . . to embark occasionally on very expensive experiments, and evidence also suggests regulators are paying investors in rate-based..."
These tendencies sound strikingly like the "out-of-market support" that "forestall[s] retirement and defeat[s] the design objective of PJM's market, at the expense of their competitors and wholesale consumers" that is precisely PJM's purported target.

In direct contradiction to its claim here that the owners of such resources have little incentive to pursue market behavior that results in price suppression, PJM states:

"... 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."

In light of PJM's strong assertion in this proceeding that "regardless of the state's specific policy motivation, retaining or compelling the entry of resources that the market does not regard as economic, suppresses prices for resources the market does regard as economic," PJM's defense of the self-supply exemption is baffling. PJM describes regulated utilities as making precisely the kinds of uneconomic decisions to retain or retire resources that it believes distort market prices.

Nor is PJM's characterization of the self-supply exemption as one that has long been in place – suggesting long-standing Commission endorsement of PJM's (current) position – wholly accurate. The Commission rejected a self-supply exemption on numerous occasions through the

269 PM Investment Whitepaper at 7, note 16.
270 PM filing at 14.
271 PM Investment Whitepaper at 8.
272 PM filing at 14.
As the Commission explained in approving the exemption, "we agree that with properly-calibrated thresholds measuring an entity's net-short and net-long positions, PJM's self-supply exemption will operate to identify those self-supply entities lacking the incentive to exercise buyer-side market power." To ensure those thresholds remained "properly-calibrated," the Commission ordered PJM to submit tariff language "memorializing its obligation to review and, if necessary, revise these thresholds on a periodic basis."

In fact, PJM itself advocated against the self-supply exemption in prior proceedings pointing to essentially the same arguments it raises in this proceeding.

Finally, to the extent that PJM believes urgent action is needed because owners of legacy assets seek out-of-market support to forestall those units' retirement, there is no basis to believe that assets that could benefit from the self-supply exemption are immune. FirstEnergy successfully pursued exactly this strategy with the transfer of the 1,984 MW coal-fired Harrison.
Power Station, previously a merchant generator, from a FirstEnergy subsidiary to another West Virginia-regulated subsidiary.

Analysts estimate the transfer of the plant to rate-payers shielded FirstEnergy from $160 million in losses over a three-year period.

As demonstrated by the proposed retirement of a similarly-situated plant, Pleasants Power Station, when it was denied the terms of a similar transfer, the transfer likely forestalled Harrison's retirement.

b. PJM arbitrarily exempts general economic development and local siting incentives

PJM proposes to exempt incentives (1) that utilize criteria designed to incent or promote general industrial development in an area and (2) from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality from its definition of actionable subsidies.

PJM offers no explanation at all for its proposed exemption of general economic development and local siting incentives from both of its proposals. There is no basis to conclude that such programs do not provide large scale support that is narrowly targeted to specific energy assets, simply because they support development within a particular area or siting within a particular locality.

Indeed, as Koplow describes, “these large subsidies to individual facilities would affect power market structure no differently than an energy-related grant of similar size or a targeted
284 Koplow's research provides only a sample of the kinds of programs likely to fall within this exemption, yet even that time-constrained review reveals numerous targeted subsidies to energy-related activities that exceed $20 million.

285 Some economic development programs work to the direct benefit of single resources, as is the case for the Pennsylvania Keystone Opportunity Zone and the Panda Power Hummel Power Station. The approximately 1,100 MW gas plant received state and local tax abatement to support its development, after receiving local official's approval under the development program.

286 Moreover, the very large billion-dollar economic development projects that directly support up- or down-stream energy sector activities can often hide cross-subsidization that benefits generation located nearby.

287 From more than a billion dollars in subsidies to local plants to support in-state demand for coal (and hence, cheaper coal generation) in Kentucky, to more than a billion and a half dollars in subsidy for natural gas development infrastructure in the Marcellus Shale in Pennsylvania (with corresponding benefits to cheap gas for regional gas generators) and a massive proposed natural gas hub laden with multi-billion dollars in foreign national and U.S. federal subsidy in the works for West Virginia, it is hard to pretend that ignoring these economic development programs ensures a

level playing field for all resources – including fuel-free resources like renewables -- in the competitive markets. Nor can one discount the direct link between these kind of economic development incentives and the decisions of market participants to enter or exit the market. First, states are explicitly aiming to change market participant's behavior through these programs. For example, in 2015 West Virginia commissioned a 55-page study to identify tax incentives that would “ultimately boost coal production in West Virginia by incentivizing the state's utilities and manufacturers to use West Virginia coal.”

There can be little doubt other states are taking similarly explicit steps to protect their preferred resources. Second, research finds a strong correlation between plant closures and the availability of these benefits intended to promote local economic development. For example, a generator that is in a state with an in-state coal mine (which are also the states that support coal as a local economic development benefit) is seven percent less likely to have closed by 2014 than a coal power plant without such in-state fuel inputs.

In concluding that state RPS programs must be subject to mitigation in order to protect the competitive markets, PJM reasoned that the programs “are expressly designed to promote the development or retention of specific types of resources” and the “[a]vailable evidence indicates...
that they do indeed contribute to that objective.”

Under a consistent approach, PJM could not categorically exempt economic development and local siting programs, which share both of those same features.

c. PJM arbitrarily ignores “material” support to conventional generators

Finally, PJM appears to categorically ignore some types of government support that meet its own definition of “material” support. As noted above, PJM has concluded that the only existing resources that would be deemed “actionable” under its proposed tariff changes are 1,400 MWs of nuclear generation, 698 MWs of RPS program resources, and 981 MWs of price responsive demand and demand response resources (as of the time of filing).

Although the definition of an “actionable subsidy” would apply by its terms to upstream incentives that, for example, reduce the cost of fuel used by a capacity resource, it seems that PJM has discounted these programs. The omission of these other forms of incentives from PJM’s consideration largely benefits conventional fossil fuel generators.

As subsidy expert Doug Koplow explains in his attached report, PJM focuses almost exclusively on purchase mandates. “But many subsidies that affect energy production prices do not fall into this category; rather, the most important subsidy mechanisms can vary widely by energy type.”

“Policies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions.”

PJM filing at 26.

Id. at Keech Affidavit, P 18.

The definition includes material payments, material concessions, or other material support obtained from state-sponsored or state-mandated processes related to the operation of the capacity resource. See proposed PJM Tariff § 1, Definitions L-M-N (Option A).

Koplow report at 2.

Id. at 10.
Further, there is "some predictability" to the effect of focusing on just some types of government incentives: capital-intensive generation will be more affected by build times, financing conditions, and changes in demand during the build period. Electricity reliant on high volume flows of input fuels are affected by subsidies to key transport links, favorable policies for pipeline building, and subsidies to extraction. Accordingly, PJM's focus on one category of subsidies will have the effect of discriminating based on technology type.

Despite the limited time afforded by the comment period, Koplow identified billions of dollars in state support to conventional generators that would appear to have the same effects on behavior offer and, per PJM's theory, market outcomes as those targeted by PJM. For example, a $1.1 billion package of support to five coal-to-liquids plants in Kentucky would keep prices for coal artificially low for coal-generators in the region (including the many in-state coal resources), while a $500 million dollar tax incentive for sales and use of coal further lowers the fuel costs to generators in that state. Coal generators relying on Kentucky coal reap additional benefits from Kentucky's lax bonding and reclamation laws for coal mines, which artificially reduce operating costs for the affected mines. The dollar value of these unfunded clean-up and reclamation costs, which would otherwise fall upon coal mine operators and the cost of coal, reaches close to half a billion dollars in Kentucky. Moreover, unlike solar and wind which...
coal generation remains more than a third of installed capacity. Thus, even if only a small percentage of the affected generators changed their retirement decisions or adjusted their offers as a result of the Kentucky coal policies, the potential for market impact appears much larger than that of the RPS policies PJM instead targets.

To provide a test case to determine whether PJM might be excluding these policies because they do not provide "material" support, Koplow estimated the value of the benefits of one of the policies PJM ignores to resources participating in the PJM capacity market.

Pennsylvania has a special sales tax exemption for coal that results in revenue losses of about $125 million per year, and about $1.5 billion over the 2007-2018 period. After breaking out the value of the subsidy that falls to coal exiting the state, or for uses other than electricity-production, Koplow compared this conservative value of the program to coal resources to the average revenue of a coal plant selling energy at the Western hub.

By PJM's own standards, the Pennsylvania tax incentive surpasses the one percent of revenue threshold of a "material" subsidy. Moreover, with more than 10,000 MWs of coal generation impacted by the Pennsylvania policy, this single program alone would trigger PJM repricing across the whole capacity market.

Yet PJM appears to ignore its own standard in concluding that its proposal would not apply to any coal generation.

Id. at 25-27. Koplow concludes that this test case is "likely part of a fairly big group of material subsidies" outside the category that PJM focuses on.
The result of PJM's arbitrary line-drawing is discriminatory impacts against buyers and sellers. PJM's wholly arbitrary targeting of some state policies but not others with the same potential market effects, has severe and harmful consequences for both market participants and wholesale customers. The discrimination, because it is not based on any meaningful economic rationale or other reasonable distinction, is by definition "undue." The Commission must reject PJM's proposals to safeguard consumers from arbitrary and unduly discriminatory rates, and, with respect to MOPR-Ex, protect suppliers from partial and unduly discriminatory access to the market.

The Federal Power Act "fairly bristles with concern for undue discrimination." Section 205 (b) of the Act is unequivocal:

No public utility shall . . . (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

In filing a revision to its tariff, PJM "bears the ultimate burden of demonstrating that the rate is not unduly discriminatory." To start, it is clear that PJM's proposals would result in differential treatment for customers. Under the capacity repricing proposal, some resources will be designated as "actionable subsidies" which will then (after the 5000 MW or 3.5 percent LDA thresholds are passed) trigger repricing in a second run of the capacity market auction. Targeted resources will have their offers repriced to higher levels, and may be replaced by a higher offer (relative to its initial offer) in the supply stack. It is a design feature of repricing that the second run of the...
As such, customers located within those LDAs will predictably face higher wholesale capacity prices than customers located in LDAs where no resources are deemed actionable.

By PJM's own estimation, the price effects of repricing will be large: as much as ten percent higher clearing prices in constrained-LDAs, and an estimated two percent higher on average.

As discussed at length in the next section, economist James Wilson concludes the price could be significantly higher, reaching into the billions of dollars.

The increase in costs for customers are likely even larger under MOPR-Ex. Instead of being subject to repricing, resources with actionable subsidies are quite likely to be excluded from the capacity market entirely. This leaves customers paying both the retail-side costs of the state program, but also with the cost of procuring replacement capacity from the market that is not really needed. Like the capacity repricing proposal, under MOPR-Ex customers located in jurisdictions with polices that are deemed "actionable" will face substantially higher capacity market prices than customers in jurisdictions where policies are not.

Under MOPR-Ex, because the targeted resources are most likely excluded from the market, supply interests are also discriminatorily impacted. The targeted resources lose a significant revenue source that non-targeted resources do not. PJM makes much about how the high rates of new gas build reflect a "market expectation" that new entry can displace incumbent resources.

Yet investment strategies are as diverse as the variety of investors in the market, and PJM ignores that many investors (not just renewable developers) could reasonably expect to...
rely on duly adopted and longstanding state laws and policies affecting the market. Where a class of investors relies on a policy that is deemed "actionable," their expectations are thwarted. But other types of investors that rely on state policies that are not deemed actionable do not face these same impacts.

Discriminatory treatment, of course, is only prohibited if it is "undue." Here, PJM's proffered basis for the differential treatment of some resources—and accordingly, for the differential prices that affect consumers—is that certain "types of resources that are not likely to raise price suppression concerns."

But as described at length above, PJM is without factual support for this claim, and substantial record evidence demonstrates it is false. Indeed, even under PJM's own (flawed) test of materiality, PJM is excluding resources that receive large enough incentives to be considered "likely to raise price suppression concerns." To take even one example, the more than 50 million dollars in external support provided to the Harrison Power station in one year easily exceeds the one percent of expected market revenue threshold to be "actionable." Moreover, again tracking PJM's own logic, the extra-market support to the Harrison Power station raises precisely the same set of concerns as a ZEC by preventing the retirement of an aging, less efficient incumbent resource. Customers in Illinois will face dramatic increases in wholesale capacity market prices under either the capacity repricing or MOPR-Ex proposals, while customers in West Virginia will not. But by the logic of PJM's own criteria, there is no meaningful difference between the customers in Illinois and in West Virginia—both are served by resources that receive "material subsidies" that pose a price suppressive threat to the market. This is undue discrimination, pure and simple.
By the same token, there is no basis for the owner of the Harrison Plant to benefit from “subsidized” access to the capacity market, while the owner of the Quad Cities nuclear plant does not under MOPR-Ex. The Commission previously declared that “we are not persuaded that determining what constitutes a ‘subsidy’ or a ‘discriminatory payment,’ . . . will be a less subjective and more precise means of preventing uneconomic entry.”

PJM’s deeply flawed and highly inconsistent attempt to do exactly that proves the point. Because PJM’s arbitrary proposals unduly discriminate against both consumers and supply, the Commission must reject the tariff filing.

C. Both capacity repricing and MOPR-Ex are unjust and unreasonable because they require customers to pay more for capacity than necessary to ensure resource adequacy. Each of PJM’s capacity proposals is unjust and unreasonable because each distorts capacity prices in a manner that harms customers. Capacity repricing forces customers to pay more for the same level of resource adequacy. It sets prices, year after year, to what they would have been if state policies did not exist. This transfers wealth from customers to suppliers that clear in the market, but will not in fact induce any greater competition or increase resource adequacy.

MOPR-Ex, by contrast, forces customers to buy far more capacity than necessary. It does so by effectively blocking capacity market access for state-sponsored resources and forcing customers to procure redundant capacity from other sources. Both proposals suffer from the same fundamental flaw: they treat revenue from state policies as different from any other revenue or cost affecting a resource’s bottom line. It is not. Revenue earned pursuant to state policies does not “artificially suppress” PJM capacity market prices, and should not be separately adjusted-for by PJM. In fact, the bulk of so-called “state...
subsidies" targeted by PJM are "externality payments" that account for "the external costs that electricity generation imposes on society" that are not priced into PJM's markets. Because such costs "should be taken into account when deciding whether or how much a resource should be used," they make PJM's markets more efficient, not less.

1. Capacity repricing inflates capacity rates without benefitting customers

Under capacity repricing, PJM would procure the correct amount of capacity for the region's customers, but at inflated prices. Capacity repricing would administer PJM capacity auctions in two stages. The first stage of the auction would determine which resources clear. PJM would arrive at the correct amount of supply in this stage by applying status quo rules wherein a resource earning revenue from sales of products such as renewable energy certificates created pursuant to state law could reflect those revenues in its offer price.

However, PJM would then proceed to overcharge customers by inflating prices through a second stage auction used to set the price paid to resources that cleared in the auction's first stage. In the second stage of the auction, which would apply once the quantity of capacity receiving state-based revenue passed a specified threshold, PJM would modify the offers from any resource receiving a so-called "actionable subsidy" to an administratively determined "Actionable Subsidy Reference Price" that would exclude revenue earned under the applicable state policy.

As shown by PJM, this offer adjustment would allow units not receiving a

IPI report at 10.

See id. at 10, 12-14.

See PJM filing at 65 (explaining that this approach allows customers to "only pay for capacity once").

Id. at 59.

Id. at 66, 83, 89.
This process, by design, would set prices higher than the amount necessary to induce the entry and retention of resources that cleared in the auction's first stage. That is not permissible under the Federal Power Act. A capacity market’s purpose is “to attract and retain sufficient capacity to meet [a region’s] reliability targets on average over time, at least cost to customers.” Capacity pricing would incent essentially the same mix of resources as operation of PJM’s status quo market rules, but at higher cost.

While PJM vaguely characterizes its capacity repricing proposal as providing for greater “investor confidence,” it fails to specifically explain how this proposal would alter the pool of resources.
Supply offers in any way that would meaningfully benefit customers or provide them with any greater resource adequacy. Closer examination of the proposal reveals that it would not.

Capacity repricing provides higher compensation to the exact set of resources that would clear in PJM's market with or without any market adjustments (i.e. the resources that would enter or remain in PJM's capacity market without the operation of the new second stage of the auction). Meanwhile, higher prices provided by the capacity auction's second stage would fail to induce any market entry or retention that would not otherwise occur because resources whose offers fall between the first and second stage clearing prices would still fail to clear. Because a resource earns no revenue when it does not clear, potential capacity market suppliers would continue to make market entry or exit decisions based on the auction's first stage clearing price, not the auction's second stage. Thus, while resource owners could have confidence that prices paid to clearing resources would be higher, that inflated clearing price would not meaningfully alter any resource's offer decisions, or change the choices of investors whether or not to attempt resource construction (except for inducing some inefficient bidding behavior, as described below). Under capacity repricing, resources would face virtually the same level of regulatory uncertainty they faced under the status quo operation of PJM's markets, because the auction round primarily influencing their entry and exit decisions—the first stage—would remain unchanged. Because it provides customers with higher costs and no benefits, capacity repricing is not just and reasonable.

Beyond this fundamental problem, capacity repricing is also unjust and unreasonable because it is structured in a manner that will skew market bidding incentives in a manner that would further harm customers. As economist James Wilson explains, a "bedrock principle" of

See infra section III.C.3.b.
capacity market design is that where a capacity market uses a sloping demand curve, the cleared quantity and price must fall on that curve. Capacity repricing violates that principle. As a consequence, market actors will not be adequately incented to compete to reduce market prices. Under status quo market rules, resource developers who believe they can beat what would otherwise have been the market clearing price for capacity are incented to enter or remain in the market. As suppliers making lower offers enter or stay in the market, that pushes prices downward. But under capacity repricing, this fundamental feature of market operations no longer applies.

A resource developer that believes it can beat the price arrived at in the second stage of the auction will not enter the market unless it also believes it can beat the price in the auction's first stage. Accordingly, in capacity repricing, there is no natural operation of market forces that will provide for the development or retention of resources that narrow the margin between the first stage and second stage prices. This means that prices will not only be inflated, but also that they are likely to stay very inflated, year after year. Nothing puts competitive pressure on the second stage auction price to keep it low.

In fact, market actors are incented to do the opposite. By divorcing clearing market clearing prices from the process by which capacity obligations are determined, capacity repricing will incent many resources to provide offers that are not reflective of their true costs and revenues. As Wilson explains, it will create an incentive for higher cost resources whose offers are unlikely to clear in stage 1 to submit above-market offers where the owners of those offers...
A resource faces the incentive to do this because by submitting the higher offer, the resource has nothing to lose but may push stage 2 prices upward, benefitting the owner's other units.

This problem has been called an incentive to "clear out the top." At the same time, resources that anticipate that their offer prices may fall above the stage 1 clearing price, but not so high as to risk being above the stage 2 clearing price, will be incented to "race to the bottom," submitting below-cost bids so as to secure capacity commitments while being paid at the higher stage 2 auction price.

Such a resource would be incented to bid below cost because so long as the stage 2 price exceeded its competitive offer, that resource would make money by securing a capacity commitment in stage 1. But while the resource owner would be rewarded for this behavior through such market manipulation, competition as a whole would suffer. Resource developers might be dissuaded from entering the market due to the risk that their offer might not be selected as a result of such manipulation even when their resource's costs and revenues would have otherwise dictated market success.

These concerns were raised by stakeholders in the CCPPSTF process, but PJM dismisses them summarily as "speculative."

Yet as Wilson explains, it is highly foreseeable that these skewed incentives would in fact translate into skewed bids. So long as there is a reasonably...
large price gap between stage 1 and stage 2 of the auction, market participants would have a fair sense whether they should attempt to "race to the bottom" or "clear out the top." Reasonable assumptions about the amount of offers that would be adjusted to an Actionable Subsidy Reference Price dictate wide price gaps. Market participants would be able to estimate this gap with increasing precision as the market dynamics of capacity repricing became better understood.

Due to these flawed dynamics of capacity repricing, over time prices across the PJM region would approach net CONE*B, the capacity offer cap. Thus, in the name of greater competition, PJM's proposal ironically would move the market toward an arbitrary, administratively-set price. Even in the immediate term, price impacts would severely harm customers. For example, assuming 9,000 MW of repriced resources (an amount less than the amount of targeted resources expected by 2020-2025, as identified by PJM affiant Dr. Anthony Giacomoni), Wilson calculates that clearing prices could increase 50 percent as compared to operation of the PJM capacity market under status quo rules. That would amount to "a total market cost of $9.1 billion" in a single delivery year. Prices would rise even more in the smaller capacity zones. These massive price increases would not provide customers with any appreciable benefits, and would therefore be unjust and unreasonable.
MOPR-Ex forces customers to buy more capacity than needed to provide resource adequacy in PJM.

MOPR-Ex, by PJM's own admission, would require customers to procure more capacity than necessary to meet the region's reliability needs. As PJM explains, "MOPR-Ex almost certainly will result in some duplication of resources needed to serve loads." It does so by adjusting the market offers of resources supported by so-called "actionable subsidies" upward to an administratively determined minimum offer that excludes the resource's revenues from the applicable state program. This will in all likelihood result in the "disqualifying [of] state-subsidized resources . . . from clearing as capacity, and will clear other resources to meet capacity needs."

But because the bulk of state policies affected by MOPR-Ex have been adopted to address the urgent threat of climate change and to reduce dangerous pollution that kills states' citizens, leads to serious health problems, and harms quality of life, states are likely to press ahead with their policies whether or not the affected resources clear in PJM's capacity market, providing additional support to resources if necessary. In PJM's words, "consistent with the state's intent, the subsidized resources will likely remain in service and continue operating in the PJM Region."

In such cases, as PJM explains, "loads will be paying for more resources than it needs."

In addition to harming customers by forcing them to pay more for capacity than necessary, MOPR-Ex would also harm the integrity of the PJM markets. MOPR-Ex's...
requirement for customers to procure an amount of capacity well above the region's installed reserve margin will "enable price suppression in the wholesale energy and ancillary services markets."

Greater supply in the energy market than economic conditions would otherwise justify will thus "make it . . . harder for otherwise economic resources to compete in those markets."

This will place a special burden on "renewable and limited-duration resources that rely more heavily on energy market revenues than capacity market revenue."

MOPR-Ex's proposed exemptions for certain state policies do not cure these fundamental flaws. The grandfathering provision for "resources that were 'procured in a program in compliance with a state mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018'" merely delays the unacceptable harms the proposal will have on customers with respect to those policies, while the carve-out for programs that are "competitive and non-discriminatory" according to PJM's judgment is so restrictive that many state-supported renewable resources will fail to qualify despite the legitimacy of the underlying policies.

But were the Commission to order a modified version of the MOPR-Ex that eliminates the RPS Exemption, the harm would be exacerbated further still. This even more extreme application of MOPR would sweep in a set of resources nearly certain to be built (indeed, for many such resources construction may already be underway), and thereby guarantee a substantial amount of duplicative costs and suppressed energy market prices. The elimination of any ability for state...
RPS revenues to factor into resource offer prices would further heighten the negative impacts of such a rule on a going-forward basis.

Were the Commission to approve MOPR-Ex or the even more extreme MOPR with no RPS exemption, the Commission rather than the states would be at fault for imposing the costs of unnecessary duplicative capacity on customers. Because the Commission is the entity responsible for setting rates for wholesale interstate capacity sales, it makes little sense to suggest that states have approved unnecessary capacity sales and thereby created the unnecessary costs. Only the Commission can do that.

In regions with capacity markets, the Commission has assumed responsibility to "reflect[] the economic value of capacity reserves" in a manner that is consistent with the region's installed reserve margin. In other words, the Commission's task in regulating capacity markets is to "ensure that there is enough generation to reliably meet load" without "overcharging . . . customers for unnecessary capacity."

While the Commission has reasoned that sloping demand curves may be appropriate due to their ability to induce more efficient pricing than vertical demand curves designed to exactly hit the installed reserve margins, any additional reserves must be procured in a manner consistent with their true value to the system.

By entirely ignoring perfectly good capacity, MOPR-Ex would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers would be receiving value for their money. The Federal Power Act's requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

351 See 103 FERC ¶ 61,201 at PP 35–36 (discussing approval of a sloping demand curve).
Further, as PJM acknowledges, the past, much more limited scope of the MOPR has not presented such a massive risk of resource duplication. The Commission has never issued an order that so baldly forces customers to pay unnecessary costs and suppress energy market prices, and the prospect of forcing customers to buy unnecessary capacity is particularly galling in this case given the massive reserve margins in PJM that clearly indicate further measures to increase supply are not necessary. Past decisions focused on deterring the construction or retention of so-called "uneconomic" generation, or preventing states from explicitly adjusting capacity prices after the fact, thereby undermining the Commission's ability to set prices.

As explained in section III.C.3.a, the state programs at issue here entail revenue

PJM filing at 56 ("[D]uplication is limited in today's MOPR, because of its narrow application to only certain gas-fired new entry resources. Consequently, existing resources selected by the state for their environmental attributes (for example) can qualify today as capacity by submitting below-cost, subsidized offers that are not addressed by the current MOPR.").

As explained in Clean Energy Advocates' request for rehearing of the Commission's CASPR Order, that order was unjust and unreasonable because there was no evidence that ISO-NE's mechanism to avoid duplicative capacity payments, the substitution auction, would work. See Docket No. ER18-619, ISO New England Inc., Request for Rehearing of Clean Energy Advocates (Apr. 9, 2018), at 31-34. With MOPR-Ex, no effort at all is made to prevent duplication. Elsewhere, the Commission has sought to avoid forcing to "pay for more resources than are necessary to provide for resource adequacy" or "provide a false signal that new investment is needed when this is not the case." ISO New England Inc. and New England Power Pool Participants Comm., 158 FERC ¶ 61,138 at P 26 (Feb. 3, 2017). By contrast, MOPR-Ex would not even attempt to prevent redundant capacity purchases.

See New England Power Generators Ass'n v. FERC, 757 F.3d 283, 295 (D.C. Cir. 2014) ("LSEs are free to shape their portfolios as they choose, including with new self-supplied resources, 'provided these new resources clear the auction."") (emphasis added)). In fact, the particular buyer-side mitigation rules at issue in that case were designed to "prevent . . excess capacity purchase." Id. at 293.

See N.J. Bd. of Pub. Utils. v. FERC, 744 F.3d 74 (3d Cir. 2014); Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1298–99 (2016) (holding that those programs functioned by modifying the capacity prices set by the Commission). In its underlying order, the Commission invited states to seek an exemption from the MOPR where the programs reflected the pursuit of "legitimate policy interests." PJM 2011 MOPR Order at P 143.
from sales of products representing environmental benefits, meaning that offers reflecting such revenue are not "uneconomic." MOPR-Ex would constitute a drastic and misguided modification to the MOPR that is not supported by past precedent.

The unjust and unreasonable nature of MOPR-Ex is highlighted by comparing it to capacity repricing. While capacity repricing imposes enormous unjustifiable costs on customers, MOPR-Ex would harm customers even more. A rough estimate suggests they could be in the range of $14 to $24.6 billion (more than $200-300 of unjustifiable costs for every customer in the PJM footprint).

These costs would be entirely in excess of those necessary to preserve resource adequacy, and would continue to grow over time with no end in sight (because states will continue to pursue the public interests they are mandated to serve). Further, the inflated resource pool induced by MOPR-Ex would push the energy market to operate in a less and less efficient manner with each successive delivery year.

MOPR-Ex is fundamentally flawed because not only will it induce entry of more resources than warranted, it sets prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM's glut of supply. Structural problems with PJM's market have already encouraged a massive overbuild of the system at great cost to customers, and MOPR-Ex would make that problem far worse, taking the market in exactly the opposite direction from what is necessary.

3. PJM's proposals are not warranted by any market failure

A core principle guiding the Commission's oversight of the wholesale markets is to limit intervention into the competitive markets to the extent needed to address a market failure. Before departing from the norm of allowing market actors to engage in economically rational behavior,

See Goggin Affidavit PP 3-4, 15.
the Commission weighs carefully whether such interference is warranted by a clearly identified market failure. This is particularly so where, as here, the market intervention comes with severe costs for the customers the Commission is charged to protect, and tremendous impacts to states, the sovereigns which share oversight over the interconnected electricity delivery system.

PJM points to the participation of resources that benefit from revenues from (some, arbitrarily-defined) state programs as warranting intervention, but it is fundamentally wrong to treat value derived from valid state property rights and obligations as "distortions" of the market. PJM is also simply wrong that the participation of resources receiving such revenues will give rise to a threat to reliability that would warrant market intervention; by its very design, market prices will rise if supply becomes low due to retirements (even assuming those retirements are driven by entry of state-supported resources). Nor does the prospect of buyer-side market power warrant tampering with the market here. To the contrary, long-standing Commission precedent holds that the renewable resources that are a primary target of PJM's proposals are an exceedingly poor tool to use in seeking to lower market prices. Moreover, because these state actions are driven by other motivations, there is little deterrence benefit of targeting them for mitigation. Finally, PJM is simply mistaken that the market interventions it proposes will have the benefit of shifting risk from consumers to supply. Its proposals will have precisely the opposite effect. For all these reasons, the Commission should reject PJM's proposals as unwarranted, vastly outweighed by the harms to customer and state interests, and unnecessary to ensure the competition that benefits the public.

A root cause of the unjust and unreasonable nature of both PJM proposals is that PJM has misdiagnosed a problem stemming from state programs that compensate generators for...
environmental benefits when in fact none exists. The state climate policies it targets are fully consistent with PJM's objective to "ensure continuation of a competitive capacity market.

Efficient market rules would allow state-sponsored resources to make economically rational capacity market offers based on the revenues they earn pursuant to state policies. Allowing this behavior is the competitive approach because it honors the rights and obligations created pursuant to state law.

While treating state property rights like any other legal obligations would be the correct approach even were the Commission the nation's sole energy regulator, the Federal Power Act's "collaborative federalism" approach that "envisions a federal-state relationship marked by interdependence" further strengthens the logic behind doing so.

Revenue from state climate policies is no different from values afforded by any state property or other legal regime. As Robert Gramlich, a former PJM economist and adviser to Chairman Pat Wood III, explains, the Commission's general practice since the inception of PJM's markets has been to allow revenues and costs stemming from public policies to affect offer prices. The Commission's role is to regulate for just and reasonable rates when accounting for exogenous market inputs, not in spite of them.

In a past order addressing PJM's capacity market rules, for instance, the Commission explicitly directed PJM to provide for the costs of state environmental policy offers.

Hughes, 136 S. Ct. at 1300 (Sotomayor, J., concurring).
regulations to be reflected in capacity market offer prices.

Similarly, NYISO's tariff includes within going-forward costs "the costs . . . necessary to comply with federal or state environmental . . . requirements that must be met in order to supply Installed Capacity."

The fact that the state climate regulations at issue in this case create revenues rather than costs does not make those economic consequences any less real. As the Commission explained in the context of demand response resources, offers from resources that also earned revenue under state retail demand response programs did not present a risk of "artificial price suppression."

Among the many reasons such a risk was not present was that such state program revenues "are actually for providing services that are separate and distinct from the payments that [such demand response resources] receive for participating in NYISO's ICAP market."

In other words, it is perfectly legitimate for revenue streams from sales of state-defined products to be reflected in offer prices, not a sign of "artificial" suppression.

As PJM explains, where a state regulation limits a unit's run time, that creates an opportunity cost because operation in any given hour may entail "giving up revenue that it could earn if it was running at a more profitable time of the year." PJM Interconnection, L.L.C., A Review of Generation Compensation and Cost Elements in the PJM Markets, at 15 (2009), available at https://perma.cc/BMV7-5QNL.

Faulting PJM for not "clearly and explicitly provid[e] for the inclusion of opportunity costs, especially for energy and environmentally-limited resources" (resources whose run time is limited by state or federal environmental regulations) in resources' default bids, the Commission ordered PJM to revise its mitigation rules to do so.

PJM Interconnection, L.L.C., 126 FERC ¶ 61,145 at P 42 (Feb. 19, 2009).

NYISO Market Administration and Control Services Tariff; Attachment H, § 23.2.1.

New York State Pub. Serv. Comm'n et al., 158 FERC ¶ 61,137 at P 33 (Feb. 3, 2017); see also PJM 2006 RPM Settlement Order at P 106 (default bids under MOPR should allow for recovery of investment costs to meet mandated environmental requirements); PJM 2007 RPM Settlement Rehearing Order at P 150 (customer is not to be shielded from costs of supply to comply with environmental mandates).

New York State Pub. Serv. Comm'n et al., 158 FERC ¶ 61,137 at P 33.

Consistent with the principle that such revenues should be included in NYISO's assessment of unit costs, the NYISO market monitor does include revenues from sales of credits compensating environmental benefits in calculating whether a unit should be
PJM is wrong that the mere fact that state programs affect wholesale market outcomes means that they are market distorting. PJM presents a highly simplified and flawed example to argue that "the state subsidy program is being underwritten by other participants in the wholesale market." But the basis for PJM's conclusion is ultimately only the fact that some market competitors will not clear the capacity market if revenues earned pursuant to a state program are reflected in the offer prices of other resources.

If the simple fact that a state policy impacted market outcomes warranted intervention, the Commission could act to undo the wholesale market effects of any state law of any kind.

The Commission has no role in correcting failures in markets outside its jurisdiction. Under the Federal Power Act, states are expressly permitted to regulate generators for the environmental harms and benefits that they impose upon their citizens. As the United States Supreme Court explained in *FERC v. Electric Power Supply Association*, the Federal Power Act "makes federal and state powers 'complementary' and 'comprehensive,' so that 'there will be no 'gaps' for private interests to subvert the public welfare.'"

Thus, the combined effect of state and federal regulation must be permitted to internalize market externalities where laissez faire exempted under Part B of the mitigation exemption test. See *New York Pub. Serv. Comm'n et al.*, 153 FERC ¶ 61,022 at P 48 (Oct. 9, 2015) (for renewable resources that are not otherwise exempt from buyer-side mitigation rules, Part B of the mitigation exemption test "takes into account certain incentives for owning renewable resources by reducing the unit-specific Net CONE").

PJM filing at 32.

See *Gramlich Affidavit at section IV* ("This is a claim about competitors, not competition.").

Even if the market rules only targeted state laws with large effects on wholesale market outcomes, that would sweep in a wide array of state laws that are well-understood to be beyond the Commission's reach, such as siting requirements, tax codes, and pollution control laws.

The market operation would harm the public interest. Because the Commission has not assumed the mantle of internalizing these externalities on its own, this dictates that states must be able to do so in a manner that flows through to RTO markets with real economic consequences. Further, internalizing market inefficiencies, as the state policies targeted by PJM do, enhances rather than reduces market efficiency by forcing generation owners to confront the true costs and benefits associated with unit operation.

It is undeniable that some state policies are inefficient, may wrongly target market behavior that causes, rather than mitigates, externalities, or may otherwise be distortive to the market of the state-regulated product. Economists who are fiercely protective of competitive markets may rightly show consternation at the inefficiencies of such policies. This can be particularly tempting where the effects of state policy decisions “flow through” to affect the wholesale markets because of the interconnectedness of the bulk and retail power systems. But it is not the Commission's job to level the playing field across the state-jurisdictional policies that apply to resources through the wholesale market rules. Rather, the Commission's responsibility is to correct failures that stem from wholesale market design (i.e. its own market).

Where a state regulates a product such as a REC that is distinct from energy or capacity, or creates a planning obligation consistent with its authority under the Federal Power Act (such as the requirement to ensure a long-term supply of renewable energy), grid operators regulated by the Commission should avoid overstepping their role and simply let those effects flow through the market, consistent with the longstanding Commission policy of allowing for rational...
competitive behaviors by market actors to set supply and demand.

The consequence of overstepping, as PJM's proposals demonstrate, is a distortion to the Commission's own markets. As described in Argument Sections III.C.1 and C.2, in this case those distortions would be the unjust inflation of rates (for capacity repricing) or the over-procurement of capacity (MOPR-Ex), and suppressing energy market rates (both proposals).

The specter of reliability crisis because of subsidies does not warrant intervention. PJM urges intervention into the market because "a part subsidized/part competitive market cannot carry out the critical function of ensuring reliability."

Setting aside the illogic of adopting drastic market changes to protect resource adequacy in a region where available supply so greatly exceeds the amount necessary to reliably serve customers, PJM's claim would be unsound even in a tightly constrained region. In addition to being premised on the fallacy that state property rights are not "true" supply costs or revenues, PJM ignores that the design of the capacity market will work to avoid such a threat to resource adequacy – even if state policies continues to "escalate."

Given the entrenched and fundamentally unavoidable nature of various types of subsidies, state and federal, that affect PJM's market, it is no surprise that the capacity market is already designed to guarantee reliability whether or not states enact policies. PJM's suggests that the market "will become less sustainable over time, because otherwise efficient, but unsubsidized resources are more likely to be priced out by the subsidized clearing price."

See Gramlich Affidavit at section V.

PJM filing at 33.

Id. (suggesting that if lower costs were the result of "real" cost reductions or real efficiencies load would benefit).

Id. at 34.
ignores the fact that resources will only be priced out if they are replaced by lower-cost state-sponsored capacity. By design, "the capacity market would react" to the economic effects of state programs. Nor would the presence of state-sponsored capacity prevent the future entry of non-subsidized resources to the extent such resources are necessary. PJM's capacity market demand curve provides that "any decrease in price" that might theoretically be caused by lower offers that reflect state program revenue "can continue only as long as there is a glut in capacity." If supplies ever dip, the market will respond by producing higher prices, sending a signal to market actors to provide adequate supply. This basic market function will continue to operate even, hypothetically, if large percentages of the capacity resources in the market received state support. Historical data demonstrates this to be true, and rebuts PJM's claim that markets with a significant share of subsidized-resource are "inherently risky and unstable." The Price-Anderson Nuclear Industries Indemnity Act, for example, provides an extremely valuable limitation on liability that was essential for the entire nuclear generation industry to emerge. In spite of the Act providing the financial support necessary for each nuclear plant to remain in operation over the entire life of the nuclear industry, the wholesale markets appear to be none the worse for wear. When reflecting state programs, as is appropriate, per the above. To the extent PJM takes issue with the composition of the capacity mix rather than the amount of supply, it is exceeding its role by ignoring valid state property rights. IPI report at 17–18. Id. at 18. Id. at 34. Koplow, 1993, at 22, supra n. 140 ("we can conclude that without federal intervention to mitigate long-term, highly uncertain risks, the market would never have developed"). In 1989, the Price-Anderson Act provided around $7.5 to $25 million in value annually to each nuclear generator, which would amount to roughly double that amount in 2017 dollars based on the Consumer Price Index ($14.8M – 49.3M). Id. at Appendix B5-5, available at https://www.earthtrack.net/sites/default/files/library/FedSubAppB5.pdf.
While PJM brushes off this vital, government-provided benefit as "nationwide in scope," it is not at all clear why a policy that benefited nearly a fifth of all generation in 1989, and supports fifteen percent of existing capacity in PJM today, would be less distortive of market outcomes under PJM's theory. Without this shifting of risk to the public, these resources would be forced to exit and would stop "crowding out" new resources seeking to enter.

Finally, because the state policies at issue have been adopted after long regulatory processes and create well-telegraphed consequences far into the future, they are unlikely to have any appreciable effect on market prices. This phenomenon further demonstrates the illogic of PJM's claims that the targeted state policies will affect resource adequacy. As economist James Wilson explains:

When certain additional resources are expected to enter or exit the market (be it "competitive" or sponsored resources), market participants will take these changes into account in planning the timing of retirements, other new entry, and other actions that affect the balance of supply and demand. If the additional resources or retirements are anticipated well in advance, it is reasonable to expect that they are fully anticipated and absorbed by market participants' adjustments, and have minimal, if any, impact on capacity prices.

As evidence from the operation of PJM's markets indicates is occurring, other market actors will adjust their entry and exit decisions in a manner that accounts for the state policies and ultimately cancels out any impacts on capacity market prices that the state policies would have.

This also undercuts PJM's unsubstantiated claim that "subsidies beget subsidies." PJM filing at 34. In spite of the long existence of the Price-Anderson Act, we do not see a proliferation of other limitations on liability among other classes of resource. It is not necessarily the case that subsidies beget further subsidies; some policies focus on achieving a particular benefit that will not be realized without government action.

Based on nuclear generation's share of total energy output among all conventional generators. Id. at 21.

Wilson Affidavit at P 22.
According to Wilson, "[w]hile the entry of the public policy resources will likely correspond to some delay of other new entry, acceleration of retirements, or adjustments by resources able to enter and exit on a year-by-year basis, this displacement is a natural consequence of the policy, perhaps even an objective of the policy."

PJM provides an affidavit from its director of market operations Adam Keech alleging that state subsidies may have a large effect on market prices, but he ignores this elementary principle that market actors will respond to each other's anticipated actions.

Wilson posits that in theory a "last-minute" state regulation could "catch[] the market totally by surprise," creating the sort of "impacts suggested by Mr. Keech's calculations, for a single auction."

But PJM has not provided any evidence that any of the state programs that its proposals address were promulgated in such a last-minute fashion, or that states are likely to carry out last-minute regulatory actions that cause significant market consequences in the future. In fact, it would be virtually impossible for a state policy supporting renewable resources to have this effect because of the long lead time required to construct these resources.

See id. at PP 20-25, 30 ("The fact that there has been so much entry (and exit) through RPM over the past several years, while RPM prices have remained in roughly the $70 to $170/MW-day range, reflects the dynamic – market participants are adjusting their entry and exit timing based on anticipated market supply/demand balance and resulting prices.

Id. at P 24.

See PJM filing, Keech Affidavit at PP 10–15; Wilson Affidavit at PP 20-33 (describing the many analytical flaws in Keech's analysis).

Wilson Affidavit at P 29.

PJM 2011 MOPR Order at P 155 ("A long lead time resource must necessarily begin construction and incurring the associated costs in advance - and often several years in advance - of the first capacity auction in which it participates."). Moreover, the long-planned procurements of renewable resources under RPS programs are projected years in advance by laws or administrative actions.
PJM's markets would self-adjust in subsequent delivery years, such that in the long term even a policy enacted at the last moment would have no deleterious impact on reliability.

Empirical evidence shows the validity of Wilson, and the Institute for Policy Integrity's conclusions that reflection of state-created revenue streams in capacity market offers will not cause a resource adequacy problem, while demonstrating that PJM's theoretically unsound predictions of price suppression and declining entry do not bear out.

Despite having been affected by all manner of external subsidies since its inception, and despite the lack of any drastic market rules such as capacity repricing or MOPR-Ex to control this spread or its effect on the PJM market, PJM can still today tout how the market's "robust competition" has produced "very robust reserve margins."

c. There is no threat of buyer-side market power to warrant market intervention, particularly from state RPS resources. PJM's filing makes plain that it is not concerned with the exercise of buyer-side market power. Its capacity repricing proposal would eliminate the MOPR (including its application to entities with buyer-side market power), while MOPR-Ex focuses "only" on "resources that are receiving a Material Subsidy." As such, it would abandon the Commission's long focus on entities whose exercise of buyer-side market power could be deterred by such rules, extending their scope to some who clearly lack such power while relaxing coverage of others that do. As explained above, revenues earned pursuant to state programs, like any other valid property right, see IPI report at 17-18. Id. at 14-17 ("There is no credible evidence that externality payments threaten the viability of markets. . . . [C]apacity markets have co-existed for years with many different subsidies, both corrective and distortive, without leading to similar resource-adequacy fears.")

PJM filing at 3.

Id. at 11.

PJM filing at 95, n. 268, Attachment DD § 5.14(h)(8).
are appropriately reflected in offer prices, meaning that low-cost offers from resources enabled by such policies would present no risk of artificially suppressing prices, even if the owner possessed buyer-side market power. But even if one discounts such state revenues as invalid, Commission precedent makes clear that renewable resources pose little risk warranting mitigation due to their particular technological and cost characteristics, reasoning that applies regardless of the support provided by state policies.

By targeting renewable and demand response resources for repricing or mitigation for the first time in the region, PJM proposes to break sharply from past Commission practice without any valid theoretical or empirical basis for doing so. The more extreme version of MOPR-Ex that eliminates the RPS exemption entirely would constitute an even greater departure from rational economic principles and Commission precedent.

As the Commission explained recently to the federal courts, PJM's buyer-side mitigation rules were "designed to prevent the exercise of monopsony power," i.e., "to identify new resources with the incentive and ability to depress auction clearing prices." The Commission further described that most recently approved exemptions to the PJM mitigation rule "were appropriately designed to identify new entry that would lack incentives to suppress market prices." The Commission thus has long tailored application of mitigation rules in PJM to target resources that pose a real risk of exercising buyer market power, because they possess both the incentive and ability to benefit by lowering their bids.

398 Id. at *19 (reflecting a judgment that the goal of preventing price suppression should be balanced against the risk of over-mitigation).
399 See supra Background Section II.
In upholding a complete MOPR exemption for renewable resources in PJM, the Commission found "persuasive PJM's justification" that "wind and solar resources are a poor choice if a developer's primary purpose is to suppress capacity market prices" due to their relatively lower capacity factors, variable output, and long lead time (which renders artificial price suppression near impossible because "a reasonable offer" would be substantially lower than that of the offer that sets clearing price due to the resource's low net avoidable incremental costs at the time it enters the auction).

The Commission's reasoning in the case would apply with the same force to resources developed under state RPS programs. Even if one wrongly concludes that it is inappropriate to reflect RPS revenues in a resource's offer, such resources would remain an ineffective means to exercise buyer-market power.

Similarly, the Commission found it unjust and unreasonable to apply buyer-side mitigation rules to demand response resources participating in NYISO's Special Case Resources program because such resources have "limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices."

The Commission had several

PJM 2011 MOPR Order at PP 153-155. We note that neither the Actionable Subsidy Reference Price used for purposes PJM's capacity repricing proposal nor the unit-specific exemption used for purposes of PJM's MOPR-Ex proposal reflects the low net incremental avoidable costs of renewable resources consistent with their long lead time to construct.

See PJM filing, proposed PJM Tariff, Attachment DD § 5.14(j)(4) (Option A) (describing the process for determining a resource's Actionable Subsidy Reference Price, which provides that a resource's full construction costs must be taken into account with "no sunk costs excluded"); PJM filing at Attachment DD § 5.14(h)(6) (Option B) (describing the unit-specific exemption for MOPR-Ex that entails the inclusion of "all project costs . . . with no sunk costs excluded"). While PJM's practice of excluding sunk costs for natural gas resources that were previously the only potential target of the MOPR may have been a reasonable measure to prevent market gaming given the feasibility of doing nearly all construction of a gas unit after securing a capacity commitment, that practice is not rationally extended to renewable resources with longer lead times and is therefore unjust and unreasonable.

reasons to justify this conclusion, including the fact that the demand response resources, "which are generally individual or small aggregated sets of 'resources'" did not "have the same ability to suppress ICAP market prices as a single, large market participant," making them "an unlikely source to either have or exercise buyer-side market power."

In making an about face to apply MOPR to renewables and demand response resources, PJM does not provide any evidence to rebut the conclusions that these resources are poor tools of price suppression, or explain why the Commission's previous reasoning is not persuasive.

d. PJM's proposal shifts regulatory risk from generators to customers

PJM claims that its proposals help to address the shift in risk from private capital to customers caused by price suppression from state subsidies, suggesting another potential basis for Commission intervention into the markets.

In fact, the opposite is true: PJM's proposals would insulate supply from regulatory risk by placing that risk on customers.

PJM makes no effort to actually show that the policies it targets transfer risk to customers, and state renewable policies and demand response programs do not in fact do so. It is not correct that the sale of RECs shifts the financial risks of operation onto customers. Precise revenues from RECs are not guaranteed to all eligible renewable resources under a state program; competition for RECs drives their price down and brings the same incentive to innovate as other forms of competition. Where eligible resources secure long-term power purchase agreements pursuant to state programs, these are often the result of winning...
competitive solicitations. As PJM itself acknowledges in its Resource Investment Whitepaper, competitive procurements “do not present the same threat” it sees in administratively-determined support. Moreover, such power purchase agreements can offer both retail consumers and the supplier value as a price hedge. One cannot categorically conclude such financial instruments are adverse to consumer interests. State demand response programs generally compensate resources for services provided to the distribution system, and are not a risk transferring tool of any kind. In contrast, PJM’s proposals protect supply from regulatory risk that could result in their being priced out of the market. As economist Gramlich explains, under normal competitive wholesale market principles, “[r]isks of public policy changes are borne by investors.” Just like “[a]ny product subject to health, environmental, safety, or other forms of regulation,” where “[p]roduct prices and stock values are changed every day” due to such regulations, electricity State policies designed to encourage energy storage resources, not clearly targeted by PJM, can similarly be designed to encourage competition. See Energy Storage Association, State Policies to Fully Charge Advanced Energy Storage: The Menu of Options, at 4 (July 2017) (setting forth a menu of competitive energy storage policy options), available at http://energystorage.org/system/files/attachments/state_policy_menu_for_storage.pdf. At least one state in PJM, Maryland, has proceeded with a competitive request for proposals for energy storage projects. See William M. Keyser and Elizabeth P. Trinkle, Maryland Issues Request for Proposals for Renewable Energy and Energy Storage Projects (June 29, 2017), available at https://www.globalpowerlawandpolicy.com/2017/06/maryland-issues-request-for-proposals-for-renewable-energy-and-energy-storage-projects/.

407 PJM Resource Investment Whitepaper at 45.

408 See id. at 28 (describing how capacity market fails to provide a long-term price hedge and expressing expectation market participants would eventually use bilateral contracts to address those risks).

409 Even in a case in which an RPS program did result in some shifting of risk from supply to consumers, these risks fall on retail customers. At the wholesale level, customers simply see the effects of these policies as reducing the cost of capacity, not as increased financial risk.

410 Gramlich Affidavit at section VIII.
investors could see their bottom line impacted by regulatory action. But under PJM's proposals, and MOPR-Ex in particular, incumbent generators have the assurance that the effects of certain state policies on their bottom line will be mitigated. That confidence comes at a high cost to customers, who pay price premiums to ensure the incumbent technologies meet their revenue expectations in the face of shifting policy preferences. But ultimately the right outcome is that supply should bear the consequences of the state authority's determination of the public interest on matters outside the Commission's jurisdiction: it is not the Commission's charge to protect particular competitors from adverse regulatory consequences of legitimate state policies.

D. PJM's proposals are not just and reasonable because they increase market uncertainty.

The Commission must also reject PJM's proposals because they would unreasonably undermine market certainty. The Commission has long-recognized the importance of clear and objective tariff provisions, particularly in applying mitigation measures, to provide needed certainty to all participants.

PJM's proposals, of which the lynchpin of each is a subjective and internally inconsistent standard, will only produce greater dispute, litigation, further rule changes, and market uncertainty going forward. Building a capacity market based on the scope of a "subsidy," which by its very nature is a subjective term, will doom the market rules to swing in direction dramatically as the political environment shifts, the nature of state actions changes and impacts different sets of market actors, and as the composition of the Commission changes.

Id.

See id. at section IV.

PJM 2009 RPM Order at P 190; PJM 2007 RPM Settlement Rehearing Order at P 180; PJM 2011 MOPR Order at P 120.
over time. This is not a recipe for enhancing the certainty market participants will need in the face of economic and technological changes that will continue to shape the energy sector. Moreover, other aspects of the proposals also threaten market certainty unnecessarily. The scope of the MOPR exemptions are confusing and do not provide clear guidance as to which state policies will be covered. This undercuts investor certainty. Placing PJM and the IMM in the role of determining the scope of an actionable subsidy is likely to be unworkable, and lead to long, irresolvable disputes. Finally, both proposals lead to market distortions that will create increasing pressure to once again change RPM market rules to correct course.

1. The proposals’ subjective standard leads to uncertainty

As described at length above, the energy sector is pervasively and fundamentally shaped by national, state, and local preferences. Energy sector policy objectives are inextricably intertwined with economic development objectives; health and safety concerns; national security and trade interests; environmental goals; and other critical public priorities. It is not realistically feasible to unwind the impacts of these policy priorities on the competitive wholesale markets. Yet that is precisely the task PJM takes upon itself, by proposing a market design that hinges on the definition of a subsidy. PJM, and the Commission as the ultimate arbiter, will face an unending series of disputes as a result. Under MOPR-Ex, market participants that may benefit from a broad definition of a subsidy because it results in the mitigation of a competing resource will push the definition to the limits. As discussed above, while PJM focuses on the alleged impacts of ZEC and RPS programs, there are numerous forms of government incentive that, either singly or collectively, will objectively meet PJM's thresholds to be treated as an actionable subsidy. If PJM does not agree to these broader applications readily, litigation may well follow. Moreover, to the extent that it appears that PJM and IMM will each share some role in interpreting the tariff language, a real prospect of diverging interpretations of the subjective
The unworkability of PJM’s definition may well create the impetus for further changes to the market construct’s threshold definitions. None of this uncertainty surrounding the ultimate scope of resources that will be deemed subject to “actionable subsidies” is helpful to settling investor expectations or market certainty.

2. The scope of the RPS exemption is unclear and further clouds market expectations. Uncertainty surrounding the scope resources that receive “subsidies” is only exacerbated by further ambiguity surrounding the scope of the exemptions to that definition. In particular, there is significant uncertainty regarding the application of the RPS Exemption to MOPR-Ex. PJM asserts that its proposed RPS Exemption is “broadly stated and accommodate[s] most state RPS programs.”

Our own assessment, set forth in detail in Appendix A, “Analysis of MOPR-Ex RPS Exemption,” raises serious questions about the claim. Of the eleven RPS programs within the PJM footprint, there is significant lack of clarity as to the eligibility of ten of the programs. Many of the exception criteria are susceptible to more than one interpretation. A broad reading, consistent with the IMM’s representations during the stakeholder process, would appropriately ensure coverage of many of these programs. Absent binding representations from PJM, states and other market participants have no certainty regarding the future treatment (post-grandfathering) of RPS resources under the exception. This puts the disposition of a significant quantity of capacity to be procured, with targets ranging from 10 to 30% or more of retail sales, under a cloud of uncertainty. Not only does this uncertainty increase market risk and hamper market decisions, it also has more immediate negative impacts. Renewable developers will factor...
into the bids the administrative burden associated with seeking an exemption and the risk that they will not be able to obtain capacity market revenues. This in turn will raise the cost to states of meeting RPS targets.

3. Market distortions that result from PJM's proposals will force further rule changes

Both the capacity repricing and MOPR-Ex proposals produce market distortions that will escalate over time, become increasingly burdensome and unmanageable, and ultimately create increasing pressure for further rule changes – and thus, more uncertainty. MOPR-Ex will increasingly result in mitigated capacity resources sitting on the sidelines, while requiring loadserving entities to procure larger and larger quantities of duplicative capacity. This will particularly be the case in light of the steadily more ambitious RPS targets adopted by states in response to the urgent threat of climate change rather than a desire to suppress prices and will not be readily deterred by the threat of possible mitigation (which remains uncertain for many resources given the ambiguous scope of the RPS exception). Forcing customers to pay significantly to procure more capacity even as capacity surpluses artificially persist and increase as a result of PJM's policy will become, at a point, untenable.

Capacity repricing, as described above, leads to perverse bidding incentives (the "race to the bottom" and "clear out the top") that will result in increasing price distortion over time. Wilson describes the phenomenon at length:

Thus, it should be expected that year to year, the distortion of offer prices would only increase. As a result of these incentives and resulting rational conduct, the RPM supply curves will become steeper and steeper over time. This is exactly the opposite of the result that is desired – gently sloped supply curves lead to competitive outcomes and relatively stable capacity prices over time, resulting in stronger investment incentives and weaker incentives to exercise market power.

416 See supra Argument section III.C.1.
Steeper supply curves lead to more volatile prices, greater incentives to physically or economically withhold, and weaker incentives for investors. This downward spiral toward ever greater price distortion, too, is not sustainable. Market participants, having adjusted to yet another new, complex capacity market construct, will face uncertainty anew as market rules are revisited once again.

CONCLUSION

For the foregoing reasons, the Commission must reject PJM's filing.

Respectfully submitted,

[signatures to follow]

Wilson Affidavit PP 70-71.
CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.

Dated at Washington, D.C. this 7th day of May, 2018.

/s/
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APPENDIX A: Analysis of MOPR-Ex RPS Exemption

A. Description of PJM's Proposed RPS Exemption

The first portion of the RPS Exemption covers "Capacity Resource[s] . . . procure[d] in a program in compliance with a state-mandated renewable portfolio standard prior to December 31, 2018, or based on a request for proposals (RFP) issued under such program prior to December 31, 2018." 

1 Proposed PJM Tariff, Option B, Attachment DD § 5.14(h)(10)(a) (attached to PJM filing as Attachment D).

This grandfathering term is broad and would cover mandatory state renewable portfolio standard programs. It does not cover resources procured pursuant to a voluntary RPS, which would affect resources procured under programs in Virginia and Indiana, as well as during the time that Illinois' program was voluntary.

In contrast, the RPS Exemption language for future procurements or future policies, Attachment DD § 5.14(h)(10)(b), is ambiguous and arguably extremely narrow. The RPS Exemption applies only to resources procured pursuant to an RPS if the entire RPS program meets PJM's specific criteria for a "competitive and non-discriminatory" program. 

2 Subsection (10)(b)(i) provides that "the Capacity Resource complies with the requirements of a state-mandated renewable portfolio standard or voluntary renewable portfolio standard." Subsection (10)(b)(ii) further requires that the terms of that program must be "competitive and non-discriminatory" and enumerates eight factors to be considered in determining whether the entire program qualifies. We therefore read the exemption to exclude from eligibility any resource procured pursuant to a program that does not meet PJM's criteria to be "competitive and non-discriminatory."

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restricted ([id. § 5.14(h)(10)(b)(ii)(7)]). "[T]he requirements of the program" must be "fully objective and transparent." ([id. § 5.14(h)(10)(b)(ii)(4)]). PJM also includes two criteria that could be read to suggest that state programs may not exclude from eligibility or grant preference to any particular renewable energy resource type. Specifically, subsection (b)(ii)(3) states that "all supplies of renewable Capacity Resources may participate," while subsection (b)(ii)(8) states that "the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas, or nuclear thermal resources." While these two terms are susceptible to multiple readings, it is possible that they could be interpreted to exclude any RPS program that excludes certain renewable types from participation in all or part of the procurement. Even if a program is deemed "competitive and nondiscriminatory" based on the criteria in subsection (b)(ii), it must also meet additional standards based on whether it awards credits (1) via auction, with winners determined based on the lowest offer prices, payments based on an auction clearing price, and the participation of at least three non-affiliated sellers; or else (2) in a manner "consistent with fair market value and standard industry practice and . . . provide that the price paid for renewable energy credits is determined by the contract terms between the buyer and the seller." ([id. § 5.14(h)(10)(b)(iii)-(iv)].

Without even considering the highly subjective and ambiguous "fully objective and transparent" criterion, a state by state analysis of 11 RPS programs in the PJM region revealed significant uncertainty as to eligibility for 10 of the state programs.

3 Most state programs this analysis is intended only to explain the risk that any of these state programs may not be deemed eligible for the RPS Exemption, and should not be construed as a statement on the part of any of the undersigned organizations that we believe the program will in fact be determined to be ineligible.
contain preferences among resource types, or exclude certain types of resources that may be considered "renewable" but have other adverse effects the state wishes to avoid incenting.

The analysis below focuses primarily on whether state RPS programs meet the criteria in subsection (b)(ii). The ten state programs that we conclude face significant doubts as to their eligibility for the exemption run into trouble before even reaching the last two parts of the exemption, which constrain the manner in which auctions can be conducted. These auction provisions, as described above, add even greater ambiguity to the viability of capacity offered based on most state programs. Auction is undefined and therefore it is unclear whether a procurement based on requests for proposals, a common structure, qualifies as an "auction" and is subject to the criteria in subsection (b)(iv), or to those in subsection (b)(iii). The restrictive means by which such auctions must proceed also prevent LSEs or state procurement agencies from considering any factor other than price in selecting the winner of the auction, contrary to the more holistic review of bids that is typically part of an RFP process. The minimum number of participating sellers also makes it impossible to assess, ex ante, whether a resource that wins the auction will in fact qualify for the RPS exemption (assuming the auction and RPS policy it implements have cleared all the other barriers).

B. State-by-State Analysis

This section provides basic, limited descriptions of renewable portfolio programs in states within PJM, focusing on program elements that are relevant to the RPS Exemption. Because PJM has provided so little in the way of interpretative materials regarding the ambiguous language in this exemption, the analysis that follows assumes a narrow application of the exemption's criteria. This analysis is intended only to explain the risk that any of these state programs may not be deemed eligible for the RPS Exemption, and should not be construed as a statement on the part of any of the undersigned organizations that we believe the program...
Delaware's Renewable Energy Portfolio Standard, 26 Del. C. § 351 – § 364, was first enacted in 2005. It sets a portfolio target of 25% renewable by 2025-2026, and requires that 3.5% of the portfolio comprise solar resources.

Certain renewable resources are not eligible, including hydroelectric power over 30 MW, and biomass that is not cultivated and harvested in a sustainable manner as determined by the state natural resource agency. Landfill gas facilities installed after January 1, 2004 must meet more stringent emission requirements to be eligible.

The law allows credit multipliers based on various geographic criteria, such as for in-state customer-sited solar photovoltaic systems and fuel cells, in-state wind turbines, and projects that are sited and a certain percentage of components were manufactured in Delaware.

Given that Delaware's targets are set for 2025-2026, over five years of procurement under this policy would not be grandfathered. The law contains preferences for different renewable resource types through both the solar carve-out and exclusions for various renewable resource types with adverse non-energy environmental impacts, potentially conflicting with the requirements in subsections (b)(ii)(3) and (8), and provides additional incentives for projects with a certain percentage of components manufactured in state, which is either an impermissible locational requirement ((b)(ii)(7)), or runs afoul of the restriction on considering factors other than price when selecting resources for the portfolio ((b)(iv)). Newer landfill gas facilities must...
meet different emission requirements than older ones to be an eligible resource, potentially running afoul of (b)(ii)(5).

2. District of Columbia

The District of Columbia's Renewable Portfolio Standard, D.C. Code §34-1431 et seq., was enacted in 2005 and sets targets of 20% by 2020 and 50% by 2032. The law specifically requires that 2.5% of the portfolio consist of solar resources by 2023.

Substantial procurement remains under the District of Columbia RPS to meet the 2020 and 2050 targets, as the 2018 target is just over 15%.

The solar carve-out in the policy potentially runs afoul of (b)(ii)(3) and (8). The structure of the RPS Exemption makes a resource eligible only if the RPS programs meet all of the criteria in subpart (b)(ii); therefore, if an RPS program does not meet those criteria, the RPS Exemption would not apply to any resource procured pursuant to that program, even resources procured for the portion of the portfolio requirement not subject to the carve-out.

3. Indiana

Indiana's voluntary Clean Energy Portfolio Goal was enacted in 2011, and establishes a target of 10% by 2025. Certain fossil-fuel based technologies are qualifying resources under the statute, including nuclear, "clean coal," and "electricity that is generated from natural gas at a facility constructed in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility."

Because Indiana's RPS includes nuclear and fossil-fueled resources, it is not a qualifying program under (b)(ii)(8), so even renewable energy resources procured through the program would be ineligible for the RPS Exemption.

7 D.C. Code §34-1432(c)(10), (c)(22).
8 Id. §34-1432(c)(13).
9 Id. §34-1432(c)(8).
10 Ind. Code § 8-1-37.
11 Id. § 8-1-37-12(a)(3).
12 Id. § 8-1-37-4(a)(17), (a)(18), (a)(21).
Illinois' Renewable Portfolio Standard was enacted as a voluntary program in 2001, converted to a standard in 2007, and further modified in 2016. Both electric utilities and alternate retail electric suppliers (ARES) are required to meet portfolio targets of 25% by 2025, but are subject to different subsidiary requirements. Electric utilities are required to meet 75% of their portfolio using wind and solar resources, whereas the equivalent requirement for ARES is 60%. Electric utilities are also required to meet a percentage of their renewable portfolio with distributed energy resources, which are those less than 2 MW in capacity, interconnected to the distribution system and used primarily to offset a customer's load. New hydropower is ineligible.

The 2016 amendments to the RPS (the Future Energy Jobs Act), requires the Illinois Power Agency, which administers the RPS, to procure various quantities of generation from new renewable energy resources over time. Any resources procured during the time Illinois' RPS was voluntary (2001-2007) would be ineligible for the RPS Exemption for grandfathered resources, which only applies to resources procured pursuant to mandatory RPS programs. Any resources procured pursuant to the RPS between now and 2025 may also be ineligible for the RPS Exemption because the Illinois RPS has several disqualifying factors. First, it gives preference to certain types

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15 Id. §3855/1-75(c)(1)(C).
17 Id. §§3855/1-10, 3855/1-75(c)(1)(K).
18 Id. §3855/1-10 (defining eligible renewable energy resources to include "hydropower that does not involve the construction of new dams or significant expansion of existing dams.").
19 Id. §3855/1-75(c)(1)(G).
renewable resources, contrary to the requirement in (b)(ii)(3) and (8). Second, the Illinois program gives a preference to existing hydropower over new hydropower, and requires procurement of new wind and solar resources, contrary to (b)(ii)(2) and (6). Finally, the distributed generation requirement could be interpreted as a locational restriction, contrary to (b)(ii)(7).

The Illinois RPS requires the Illinois Power Agency to run competitive procurement processes that eventually results in power purchase agreements between suppliers and utilities. It is unclear whether these application- and bid-driven procurement processes amount to an "auction" and therefore, whether subparts (b)(iii) or (b)(iv) further governs the eligibility of resources procured pursuant to this state program. If (b)(iv) were to apply to the Illinois procurement process, then Illinois' requirement that contract prices be "cost effective" would disqualify the program based on the (b)(iv) requirement that "payments to winners [be] based on auction clearing price."

5. Maryland

Maryland's Renewable Energy Portfolio Standard was first enacted in 2004 and subsequently revised in 2006. The law sets a target of 25% by 2020, and requires that 2.5% be met by solar resources. In 2013, the legislature revised the standard to impose a carve-out for offshore wind, in an amount to be determined by the Maryland Public Service Commission, but in no case more than 2.5%. Only resources within PJM are eligible.

21 Id. §3855/1-75(c)(1)(D).
24 Id.; see also http://programs.dsireusa.org/system/program/detail/1085.
The offshore wind and solar carve-outs in the Maryland RPS would most likely disqualify all resources procured under that program, as those carve-outs constitute forbidden locational preferences ((b)(ii)(7) and differentiation among renewable resource types ((b)(ii)(3), (8)), respectively. In addition, the mechanism through which the Maryland Public Service Commission considers and awards contracts for offshore wind projects may be viewed by PJM or the Independent Market Monitor as insufficiently competitive to qualify for the exemption. In spring 2017, the Maryland PSC agreed to grant offshore wind renewable energy credits to two offshore wind projects totaling 368 MW (nameplate) in a proceeding that only involved two competing applicants, but subsection (b)(iv)(3) requires a minimum of three bidders in any "auction-type" process to be competitive. Although these two offshore wind projects would likely be eligible for the RPS Exemption under section 10(a), it is possible that future offshore wind procurements by the Maryland PSC will also have a small number of bidders, given that the very purpose of the Maryland Offshore Wind Energy Act of 2013 is to promote the development of a nascent industry in the United States.

Michigan

The Michigan Renewable Energy Standard was first enacted in 2008 and updated in 2016. It establishes a standard of 15% by 2021, with a goal of 35% of electric needs "met through a combination of energy waste reduction and renewable energy by 2025."

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27 See H.B. 266 (2013).

28 Act 295 of 2008; Senate Bill 438/Act 342 of 2016; MCL 460.1001 et seq.

29 MCL 460.1028(1)(c).

30 Id. 460.1001(3).
portion of these targets can be met with Advanced Cleaner Energy Credits ("ACECs"), which can be generated by gas- or coal-fired technologies with significantly reduced carbon dioxide emissions.

The Michigan statute awards various credit multipliers for renewable generation from existing solar, generation at peak load times, generation used to charge storage systems later discharged at peak times, and from resources constructed using a Michigan workforce.

A final relevant program element is that renewable energy credits can be obtained from out of state resources, but only if they are located "in the retail electric customer service territory of any provider."

The Michigan Renewable Energy Standard has several criteria that may render resources procured pursuant to it to be ineligible for the RPS Exemption. First, resources relying on natural gas and coal as fuels are eligible for some portion of a utility's RPS obligation, in conflict with (b)(ii)(8). Second, the credit multiplier for certain existing solar resources conflicts with subsection (b)(ii)(5) which excludes policies granting preferences to either new or existing resources. The program also includes a locational restriction in conflict with subsection (b)(ii)(7), by making out of state resources eligible only if they are in the service territory of a utility subject to the law.

7. New Jersey

The New Jersey Renewables Portfolio Standard was originally enacted in 1999 and has been updated several times. The current target is just under 18% by 2021, with a carve-out

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31 Id. 460.1003(d).
32 Id. 460.1039(2).
33 Id. 460.1029(1).
34 S.B. 2936 (included distributed generation to produce RECs/SRECs) (2007); A.B. 3520 (included solar specific provisions) (2010); S.B. 1925 (includes low-impact hydro facilities less than 3 MW as Class I) (2012) (included offshore wind provisions) (2010);
A 2028 solar portfolio standard of 4.1%.

Hydro-electric resources built prior to 2012 are not eligible.

The New Jersey Assembly and Senate recently approved legislation to increase its renewable energy mandates, create energy storage goals, and provide subsidies to the state's aging nuclear power plants. A

increases the state's RPS to 50% by 2030 and requires generators to source an increasing amount of their electricity from behind-the-meter solar, to reach 5.1% by 2021.

That legislation has not been signed by the governor at this time these comments are filed.

The Offshore Wind Economic Development Act of 2010 requires that each electric power supplier and each utility meet a portfolio target for offshore wind energy, amounting to 1.1 GW of offshore wind projects.

The Board of Public Utilities (BPU) has sole jurisdiction to approve an offshore wind renewable energy certificate (OREC) price that will allow an applicant to satisfy the cost-benefit standard set forth in the statute. Governor Phil Murphy recently issued an executive order "directing the [NJBPU] to fully implement the Offshore Wind Economic Development Act (OWEDA) and begin the process of moving the state toward a goal of 3,500 megawatts of offshore wind energy generation by the year 2030."


Like many of the other state RPS policies described here, New Jersey's RPS includes a carve-out for solar resources, rendering any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8). New Jersey's RPS also includes a carve-out for offshore wind energy, in conflict with the prohibition of locational restrictions in subsection (b)(ii)(7). Furthermore, assuming that the OWEDA procurement mechanism is deemed to be an auction, then the price paid for the resources must be determined by the auction clearing price; by contrast, New Jersey law calls for the OREC price to be administratively determined by the NJBPU at a level "which will achieve the purposes of the Act at the least cost to ratepayers."

North Carolina

The North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") was enacted in 2007, and establishes a target for investor-owned utilities of 12.5% by 2021. The policy includes carve-outs for solar as well as for projects generating energy from certain animal waste products. These carve-outs render any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8).

Pennsylvania

The Pennsylvania Alternative Energy Portfolio Standard was enacted in 2004 and sets a target of 18% by 2021. The standard includes two tiers for which different resources are

43 Id. at §62-133.8(d) – (f).
eligible, and a small solar carve-out. Resources eligible for the second tier include waste coal and integrated combined coal gasification technology.

The Pennsylvania Alternative Energy Portfolio Standard has several criteria that may render resources procured pursuant to it ineligible for the RPS Exemption. First, resources relying on coal as fuels are eligible for some portion of a utility's RPS obligation, in conflict with (b)(ii)(8). Second, the solar carve-out renders any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8).

Virginia

The Virginia Voluntary Renewable Energy Portfolio Goal was enacted in 2007 and establishes a target of 15% by 2025, and a cap of 20%. Because Virginia's policy is voluntary, none of the resources already procured under this program would be grandfathered under section 10(a) of the proposed RPS exemption. The program does not appear to have any potentially disqualifying factors for any future procurements.

In 2008, Ohio enacted its Alternative Energy Portfolio Standard (AEPS), as part of broader restructuring legislation, establishing a renewable portfolio standard of 12.5% by 2025, including a small solar carve-out. The initial standard also imposed a separate 12.5% target that could be met with either renewable energy or "any new, retrofitted, refueled, or repowered generating facility located in Ohio." In 2014, Ohio froze the AEPS compliance schedule for two years and removed the separate requirement for fossil-fuel related alternative energy sources. The current standard requires 12.5% renewable energy and 0.5% solar energy by 2026. The solar carve-out in Ohio's AEPS renders any resource procured under this RPS potentially ineligible for the RPS Exemption, per subsection (b)(ii)(3) and (8). Moreover, it is possible that renewable energy resources procured during the time the AEPS also required procurement of fossil-fuel related alternative energy resource could be excluded from the grandfathering protection of subsection 10(a) because the RPS program would have, at that time, be in conflict with subsection (b)(ii)(8).
Appendix B – Expert Affidavits and Reports
Energy Subsidies within PJM:  
A Review of Key Issues in Light of Capacity Repricing and MOPR-Ex Proposals

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1. Introduction

This paper evaluates a proposal by PJM Interconnection to address certain state subsidies that it contends harm the competitiveness of capacity auctions within its territory. Subsidies, whether through state, federal, or local policies, are pervasive in the energy sector. This paper assesses PJM’s proposed method for screening actionable subsidies in the context of an extensive literature on energy-sector subsidization to highlight ways in which their approach fails to address subsidies in a neutral manner.

In an April 9, 2018 filing submitted to the Federal Energy Regulatory Commission (FERC), PJM proposed two mutually exclusive options to protect capacity auctions from the impacts of these subsidies.\(^1\) **Capacity repricing** would increase the market clearing capacity price paid to all bidders that clear by adjusting bids to account for subsidies received by certain generators, though would not alter which specific bidders cleared. A second option, MOPR-Ex would adjust the bid price for subsidized resources prior to evaluating their competitiveness, changing the mix of facilities that would clear the capacity auction. PJM believes the first option would be more accommodative to allowing state preferences and goals within the power sector to continue to survive in the market place.

PJM’s filing describes the types of subsidies that would be “actionable” under its proposals, including policy types, materiality, and exclusions. In doing so, PJM embarks upon a challenging task: subsidies flow to all forms of generation, and nearly every upstream and downstream stage of each power-related fuel cycle as well. Moreover, focusing only on currently-active supports ignores the fact that historic subsidies may have underwritten long-lived capital investments that remain in place, even if the subsidies themselves have been reduced or eliminated. These older policies may thereby have the same type of market effect as current subsidies: allowing affected units to offer in at lower prices than otherwise would have been possible. Further, gaps either in PJM’s definition of actionable subsidies, or in the data needed to quantify actionable interventions, may result in material interventions being ignored. Finally, equity issues may arise where units reliant on subsidies that pre-date the inception of capacity markets are suddenly being penalized for them and potentially forced out of the marketplace.

PJM’s description of which subsidies are actionable initially seems broad enough to capture most types of potential subsidy. However, exclusions added just a few paragraphs later winnow down coverage in ways that are likely both material and unequal in how they affect different fuel cycles. Even if the wording suggests particular subsidies should be included for review, how PJM interprets these definitions in practice remains unknown. The particular subset of actionable subsidies that PJM highlighted in its April filing was quite narrow and ignores many subsidies that affect the market in similar ways (PJM 2018; Giacomoni 2018).

PJM’s listed examples consist almost exclusively of “purchase mandates,” which are statutory targets for consumption of particular forms of power that must be met within a geographic region even at above-market prices. Most commonly, these take form of renewable portfolio standards, tradeable renewable energy credits, and newer zero emission credits that attempt to protect incumbent nuclear generators.

But many subsidies that affect energy production decisions do not fall into this category; rather, the most important subsidy mechanisms can vary widely by energy type. As a result, if there are data gaps related to particular policy types, some fuel cycles may be unaffected while estimates for others are highly inaccurate. There is some predictability to the patterns: capital-intensive generation will be more affected by build times, financing conditions, and changes in demand during the build period. Electricity reliant on high volume flows of input fuels are affected by subsidies to key transport links, favorable policies for pipeline building, and subsidies to extraction. Accordingly, PJM’s focus on one category of subsidies will have the effect of discriminating based on technology type.

More specifically, purchase mandates are very significant for renewable power and increasingly for old nuclear plants as well, though play no role for natural gas. Credit support such as subsidized loans, tax exempt debt, or government guarantees on private borrowing, are important for nuclear power but fairly immaterial for wind and all but the largest centralized solar installations. Liability caps are material primarily for nuclear and oil transport; subsidized state ownership for nuclear (waste management) and large hydroelectric power facilities. Royalty reductions, uncompetitive lease auctions, and subsidies to linking infrastructure (often at both the state and federal levels) bolster fossil fuels but are immaterial for renewables.

This paper provides a brief introduction to the types of subsidies often flowing to energy facilities, and evaluates the planned scope of subsidy review proposed by PJM to identify areas of potential concern. There is no single data source that tracks and values all subsidies flowing to PJM facilities and associated production, and this paper makes no claim to play that role. Rather, by piecing together available data and actual examples, the goal here is to illustrate potential gaps and hidden distortions in the current policy formulation.

Identifying and quantifying relevant subsidies within a short time frame and limited budgets is not easy. Even if bidders are required to submit this information, some ability to validate the data provided will be needed within PJM. Further, because estimates of actionable subsidy magnitude drive bid adjustments that may have large and expensive competitive ramifications, challenges by affected parties would seem likely, further complicating the process.

2. Actionable Subsidies as defined by PJM leave a great deal out

In defining which subsidies would be “actionable” under its proposal, PJM aims to capture key supports that materially reduce the price at which a resource can bid into the capacity auction. The proposal also aims to exclude programs and policies that have a small
effect and won’t alter the clearing price. Using a number of metrics listed below, this paper evaluates whether there are gaps in PJM’s proposed approach and whether those gaps will result in a system that is not neutral across market competitors.

- **Political jurisdiction.** Are there types of governmental entities or levels of government being excluded from review, but that are likely to provide material subsidies?

- **Materiality at plant level.** Do any of the subsidies that PJM’s definition would exclude have material impacts on generator revenue? Is the measurement of subsidy impact on cost structure being done in a neutral way?

- **Intervention type.** Subsidies to PJM market participants take many forms. Some are easy to see and to measure; others are complicated and may be largely missing even from available government data. What are the policy gaps in the PJM proposal, and what type of bias might they introduce? Are there notable differences between available data on state subsidies and the examples included by PJM in its FERC filing?

- **Energy type.** Are subsidies to both incumbents and new entrants being addressed equally? Are particular forms of energy being treated differently? Are subsidies to upstream (extraction, transport) and downstream (facility decommissioning) relevant to the economics of power generation in the region? If so, are they being included?

### 3. Systematic exclusion of federal subsidies and many sub-national supports will bias results

PJM’s definition initially appears fairly inclusive, reflecting any “material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource.” (PJM 2018: 69).

“Any government entity” would seem to include local, state, or federal support, recognizing that it is often the combination of support from these different jurisdictions that tips projects from non-investable to investable; or keeps marginal facilities from shutting down. As PJM Senior Market Strategist Anthony Giacomoni observes, state subsidies generally have the effect of causing certain resources to be viable where they might not otherwise be: (Giacomoni 2018: 6):

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2 Erickson, Downs, Lazarus and Koplow (2017) modeled the effect of state and federal subsidies on 800 US oil fields to evaluate the degree to which they relied on subsidies to hit investment hurdles. Nearly half of the fields were uneconomic at $50 per barrel oil (the price at the time of publication), and the modeling illustrated the importance of not looking at a single subsidy in isolation.
While my affidavit does not attempt to calculate whether each resource that receives a state subsidy would not enter service, or would not remain in service, without the subsidy, it is reasonable to conclude, as a general matter, that these subsidies cause more MWs of the favored resource types to be in service than would be the case without the state subsidies. In other words, without these subsidies from outside the PJM wholesale market, some portion of these subsidized resources would not be economic.

Yet the basic principle he highlights applies to all subsidies, regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted. A large subsidy is likely to distort market behavior, creating winners and losers in the process, regardless of its form. Any system of oversight must be carefully constructed such that the full array of influences is visible, and it is in this context that the many exclusions indicated by PJM must be evaluated.

3.1. Blanket exclusion of federal interventions is unjustified

Federal interventions can be large and targeted. PJM excludes all federal-level subsidies. While it argues that federal subsidies inherently have a broader reach and don’t discriminate based on geography, and therefore are less likely to have a discriminatory impact on the marketplace, that is often not true (PJM 2018, 70, 71).

Although federal subsidies may be open to all states, they can also be both large and highly targeted. The Department of Energy’s Title XVII loan guarantee program, for example, has provided federal credit support on the order of hundreds of millions or billions of dollars to a handful of specific facilities, including power generation. The tenders are somewhat competitive; however, so is state-level bidding for RPS capacity. Title XVII projects often have some technology risks; but so do new offshore wind facilities planned within PJM member states and that are called out specifically as problematic subsidies within PJM’s filing (Giacomoni 2018). Structurally, there is no reason to believe that Title XVII credit subsidies would not affect capacity market bids in a very similar manner as state subsidies.

While a review of DOE’s current loan portfolio (DOE 2018) found no active generation projects within the PJM region (one solar project was discontinued and there are a couple of large loan guarantees to advanced vehicles, another part of the program), it remains possible that loans will be granted under the program in the future. The scale of support under Title XVII can be so large that ignoring its impact on capacity markets simply because the subsidy originated at the federal level seems unsupportable. DOE continues to have open rounds for new lending, so a PJM-based generation project is a real possibility. Subsidized projects in the existing portfolio in nearby states could also sell into the region.

Federal interventions can disproportionately benefit a class of firms. Even where federal spending is not targeted to a single facility, it may support a particular type of generation in a manner that provides a competitive advantage to that class of facilities. Federal support to nuclear power is an example of this. There are fewer than 100 operating reactors in
the US, of which roughly 45 are in the PJM service area (NEI 2017). Federal subsidies are largely additive to state subsidies. Federal tax and insurance subsidies, as well as de facto state ownership of parts of the fuel cycle, all subsidize the operating costs of nuclear plants. This includes plant decommissioning (tax breaks on earnings of Nuclear Decommissioning Trust Funds), insurance against liability for reactor accidents (capped under the Price Anderson Act of 1957), and building and managing a long-term repository for high level nuclear waste (a complicated and complex endeavor that has effectively been nationalized) (Koplow 2011). Even where federal subsidies flow to a much larger set of beneficiaries, such as oil field operators (Erickson, Downs, Lazarus and Koplow 2017), data indicate both that the competitive impacts are significant and that the magnitude of federal subsidies frequently exceeds that of the state support.

Large new federal subsidy programs could also affect the PJM market. Finally, the Trump Administration continues to promote one plan after another to use federal leverage and treasure to stem the market-based decline in coal and nuclear. The most recent iteration of this push is to use the Defense Production Act (DPA) to bolster the facilities (Dlouhy and Jacobs 2018). Were the DPA, or any of the other proposals that have been floated, actually to take effect, the use of federal credit, purchasing power, or other support to specific plants would be large. Yet, under the PJM repricing and MOPR-Ex rules as currently proposed, these enormous subsidies would be left unaddressed. This could result in a situation where adjustments were being made to one class of generators (because they rely on state subsidies) but not others (who receive mostly federal support).

3.2. Many state and local subsidies would also be ignored by PJM

Subsidies to “incent or promote” either general industrial development in an area or to lure production or jobs from one county or locality to another county or locality are not actionable under PJM’s proposal (PJM 2018, 70). While these types of subsidies are more common at the sub-national level, federal subsidies may also sometimes be designed to trigger development in a particular region (and so would be excluded from consideration under two separate limitations proposed by PJM).

But subsidies deployed for purposes that would be excluded under PJM’s proposed definition are sometimes both very large and narrowly targeted to specific energy assets. These large subsidies to individual facilities would affect the structure of power markets no differently than an energy-related grant of similar size or a targeted tax break. The effect of subsidies on bid prices within PJM capacity markets will depend on the scale of the subsidy, not its justification.

An example from the federal level demonstrates how such subsidies can flow to entities with significant political and economic power. After Hurricane Katrina battered the Gulf Coast in 2005, the US Congress authorized billions of dollars in tax-favored Gulf Opportunity Zone bonds. The bonds were supposed to help rebuild the entire region, though in that region the oil and gas industry is both large and powerful. Within the state of Louisiana, $7.8 billion in
bond capacity was created, of which the oil and gas industry captured 57%. Once joint projects with the sector and related industries were included, their share rose to 65%. Two oil and gas projects received more than $1 billion in bond capacity each (Koplow 2012).

Good Jobs First, a Washington, DC- based organization, has been tabulating government subsidies to specific industrial facilities for many years. Their Subsidy Tracker database compiles information from hundreds of different government agencies around the country. Table A.1 is an extract of subsidies to energy-related activities within PJM states that exceeded $20 million. While the subsidies are both large and targeted, they are often granted under the auspices of regional development or plant location; as a result they would be immediately discarded by PJM. Some examples help illustrate common issues that arise when evaluating power-sector related distortions.

Coal conversion plants in Kentucky. Heavily reliant on coal jobs, and facing declining demand in the power sector, Kentucky was looking to diversify one of its core products. Between 2007 and 2011, the state provided large subsidies to five different coal-to-liquids plants. Despite most of these projects stalling out (it’s hard to sell expensive gas from coal when fracked gas from the ground is so cheap), the examples raise a number of relevant issues.

- **Scale.** The multi-year support packages totaled more than $1.1 billion. The support to individual plants was as high as $550 million. These subsidies would be of equal or greater scale to many of the tax expenditures benefitting the sector.

- **Power-sector relevance?** At first glance, these subsidies are to coal, not the power plant – though coal is primarily used to make electricity. Further, these particular facilities were making liquid fuels that mostly were destined for heating and transport applications. So are they irrelevant to PJM power production? If subsidies are small, the likely answer is “yes”. If they are billions of dollars, further evaluation would be needed, as subsidizing the coal ecosystem could have important ancillary benefits for coal-fired power plants. For example, the conversion plants could have kept mines and railroad links open and running at efficient utilization levels, allowing them to continue to serve particular power plants too old to retrofit for a different type of coal or too marginal to incur higher transport costs. For large subsidies, some screening would be warranted before dismissing them as irrelevant.

- **Development or not?** The awarding agency for all of these subsidies was the Kentucky Economic Development Finance Authority. As noted earlier, under PJM’s proposal, subsidies to regional development would be excluded from being actionable. But the specific program was through the Incentives for Energy Independence Act, which in Kentucky is nearly all about coal. The larger subsidies on offer from states often pull from multiple programs run out of multiple state agencies. Functionally, they may span excluded regional development and included oversight or energy-focused missions.

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3 Available at https://www.goodjobsfirst.org/subsidy-tracker.
Some may receive a mix of state and federal support. The lines are often gray, making PJM’s proposed test hard to administer.

**Natural gas infrastructure for Marcellus Shale.** Gas prices in the Marcellus region continue to be significantly lower than the Henry Hub benchmark. At least part of this is due to gas being stranded in the region as surging production ran into limited offtake capacity. Boosting gas exports to other parts of the country, and to the world, would increase the likelihood of prices equalizing across regions. A related issue involves constrained outlets for wet gas in the region.

Are massive subsidies to natural gas infrastructure relevant to consider for PJM capacity markets or not? Natural gas plants are the most significant cause of disruption to incumbent plants within PJM (Jenkins 2018), including reducing the infra-marginal revenues that older nuclear plants can earn to stay afloat. This “missing money” in turn has opened the political spigot for billion dollar bailouts to reactors. To the extent PJM undertakes to address subsidies, PJM should be carefully and systematically evaluating whether subsidies of any type within the natural gas fuel cycle are accelerating or exacerbating the disruption of older baseload generators.

Richard Porter of FTI Consulting in Houston remarked to *Bloomberg* that as natural gas transport stabilizes, producers will have “a surety of market and revenue stability,” as well as additional cash flow to fund exploration programs (Kovski 2017). And while gas prices to electric power may rise, the transport component, which “at times has been as much of a market factor as the value of the gas” should fall (Kovski 2017). Rising demand for Marcellus gas is driven by the power sector. However, increased capacity to process natural gas liquids and to liquefy gas for export will both help to feed continued production as well. The degree to which subsidies to related infrastructure result in more gas, cheaper and more reliable gas to power plants, and a continued undercutting of other capacity supplies is not easy to gauge. But it is reasonable to believe there are relationships, and those need to be explored in more depth.

Some of the subsidies of relevance:

- **Shell Ethane Cracker plant in Pennsylvania.** The facility will add desired capacity to handle natural gas liquids, boosting returns to natural gas fields. Pennsylvania has provided $1.65 billion in tax credits to the facility, the single largest subsidy to the energy sector in PJM identified in the *Subsidy Tracker* Database.

- **Dominion Cove Point Natural Gas Liquefaction facility in Maryland.** An increasing share of Marcellus gas is heading for export, and Cove Point will accelerate this shift. Tax abatements worth about $500 million over 14 years were offered to the plant by the Board of County Commissioners in Calvert County. This is a very large subsidy for a county government. It is also one that has been criticized by some tax experts who argue that much of the infrastructure needed to move in the gas was already on the site, that it will be the only LNG facility on the East Coast, and that the site has prime
access to gas from the Marcellus region. While Dominion threatened to leave absent the tax abatements, the company would have lost a great deal from doing so, these analysts argue, and likely would have stayed even with no subsidy. (Ehrenfreund 2014).

Build it and they will come: the Appalachian Storage Hub. As PJM works to ensure competitive transparency among its capacity providers, very large moves by state actors appear to be afoot within the region, with investments approaching $100 billion. This creates a new and difficult set of challenges to protect markets.

On this particular project, a combination of state and local support justified on economic development grounds, subsidy terms hidden in private contracts, federal support, and subsidy targets upstream of power plants are all interventions that would fall into PJM’s exclusions or on which public data would not be available. As a result, all would escape consideration by PJM as actionable subsidies – no matter how large they end up being.

The planned hub will straddle PA, OH, WV, and KY (Horn 2018), all parts of PJM. It is likely to include a mixture of investments, including natural gas liquids storage, a market trading center, feed capabilities into multiple key pipelines, and chemicals production. Some of these may be irrelevant to gas-fired power generation; other assets may be dual use, or create subsidized offtake capacity that allows market-based frackers to boost supply to power markets at an artificially low delivered price. This will be an issue of particular import where the investments are in states – like Pennsylvania – with severance and property tax rates at zero.

The major player at this point is China Energy Investment Corporation (CEIP), a massive state-owned Chinese firm formed from a merger of China Shenhua Group, China’s largest coal producer, and China Guodian Corp, one of its largest utilities. CEIP signed a memorandum of understanding with the State of West Virginia in November 2017 to invest $83.7 billion over 20 years. A first phase plan, with $4 billion in investment, is supposed to take place over the next two years (Smith 2017).

Details of the MOU have not been made public. Multiple Freedom of Information Act requests are pending, but so far have unearthed few details on the scope or magnitude of public subsidy at play on either the Chinese or the US sides of this deal. One detail that has come out is a potential $1.9 billion subsidized loan for the project under the Department of Energy’s Title XVII program discussed earlier (ADC 2018).

Big subsidies from the Chinese side are also likely. China has been active worldwide with state-led development deals to secure access to strategic minerals, including energy. Chinese state-owned enterprises routinely benefit from state support, including through preferential taxation and access to favorable credit terms.4 This project is unlikely to be

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4 A detailed review of China’s foreign aid strategy by Wolf, Wang, and Warnerthe (2013) found that “such programs have burgeoned in recent years, with emphasis on development of increased foreign supplies of energy resources, as well as supplies of ferrous and nonferrous minerals. Loans finance many of these programs and feature substantial subsidization, but are also accompanied by rigorous debt-servicing conditions that distinguish
different. CEIP itself is viewed as a strategic enterprise by Moody’s; it is likely the Chinese government shares this view, and will use the leverage of the State to support it.5

In March 2018, the State of Ohio announced an ethane cracker with an estimated cost of $10 billion was going to move forward in Belmont County with backing from Thailand’s PTT Global Chemical and South Korea’s Daelim Industrial Co. (Junkins 2018). As with the other portions of this deal, information on state subsidies, either foreign or US, remains sparse.

In mid-April, the US and other trading partners raised a concern at the World Trade Organisation about state subsidies leading to creation of overcapacity in key industries, and how that overbuilding harms market competitors. While the communication mentioned steel and aluminum, similar arguments apply to mega projects such as the Appalachian Storage Hub. The submittal noted that

...capacity is often created pursuant to industrial policies to develop national strategic industries or to maintain the companies in these industries if they begin to fail. The overarching point in these instances of creation and maintenance of capacity is that the relevance of market forces diminishes when the state – functioning as the leading economic actor – owns, controls, or influences large industrial enterprises and banking entities. Simply put, direct or indirect government ownership and control can result in political considerations dominating what should be exclusively commercial decisions. This is especially problematic when the state owns or controls both the lender and borrower in a financial transaction. (WTO 2018).

4. Simplifying Actionable Subsidies: PJM focuses on the revenue side, but reducing costs or return uncertainty affects market offers in the same way

PJM’s definition of actionable subsidies focuses on revenue impacts, but these are not the only way subsidies boost expected returns of a subsidized activity. Policies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions. PJM appears to focus only on revenues, stating that capacity repricing “is including only those subsidies that would have a material impact on the seller’s overall revenues from the subsidized resource” [emphasis added] (PJM 2018: 69).

Similarly, its de minimis test focuses on revenues as well. If PJM intends this to capture “net revenues” (though the proposed tariff language suggests it does not), that would

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5 In a note discussing the merger last year, the firm wrote “Moody's also believes that the combined entity will continue to have a high strategic importance to China’s energy sector, due to its positions as the largest power generation company and coal producer in the country. The combined entity will also be the largest wind power generation company in China.” (Moody’s 2017).
incorporate reduced costs to some degree. However, there is some risk – as is common with royalty calculations that allow deductions for expenses such as transportation – of gaming by bidders. The overall magnitude of support, whether on the cost, revenue, or risk stabilization side, would be a more neutral metric. Further, definitions that leave only revenue impacts as the focal point suggest that PJM intends to focus primarily on purchase mandates, rather than other forms of government support as well.

5. Definitional and data problems will systematically exclude some types of support from review

Subsidies can be created by many different policy mechanisms. These vary widely in complexity. Direct spending and research and development (R&D) support involve visible line items in budgets, where both the amounts and the purpose are clear. Revenue losses to the government Treasury from tax expenditures are increasingly estimated as part of the standard budgeting process, even at the state level. Even with this positive trend, however, the estimates are less precise than direct spending, and are much more difficult to allocate to beneficiaries. Most tax expenditure data sets, including the ones used to support this paper, also have some gaps. Understanding where they are, which are material, and whether different states have the same gaps, can all be challenging. Assessing the competitiveness of natural resource lease auctions, or the value of liability transfers, is also quite difficult to do. As a result, these types of supports are often missing entirely from subsidy assessments.

A lack of information, unfortunately, is not correlated with a lack of subsidization. In fact, because receiving large subsidies can sometimes create reputational risks for both the politician and the recipient firm, there may be perverse incentives to shift larger value subsidies to less visible and more-difficult-to-value mechanisms.

To the extent that PJM is ignoring entire classes of subsidies, such as those arising from state tax policies, the risk of bias across fuel cycles rises substantially. This is true whether the exclusion results from a definitional oversight in what PJM wants to track; or from policies that PJM’s definitions seem to include, but for which data allowing valuation and attribution aren’t readily available.

5.1. Assessing category gaps in PJM subsidy definitions

Translating a general definition of actionable subsidies into a more detailed roadmap of what types of policies might be overlooked is an important step in gauging areas where the current proposal may need adjusting. Definitional gaps are assessed by comparing my generic overview of key subsidy mechanisms (Table 1, below, left column) to information from PJM. This includes the definition PJM incorporated into its FERC filing, and a breakout of subsidy types assembled by the Capacity Construct Public Policies Senior Task Force (CCPPSTF) over the
course of work prior to PJM’s filing. Potential gaps are noted in Table 1 as well. Despite the length of the table, the exercise is a useful way to identify potential gaps in a structured way.

Tracking subsidies via direct spending appears to be well addressed by PJM. Tax revenue foregone and credit support are both also covered in the PJM definitions and state action categories. However, significant holes likely remain regarding how well these classes of support are tracked in practice. Liability subsidies and subsidized provision of energy-related goods or services are not well captured in current PJM actionable subsidy formulations. With the exception of direct spending, all of these subsidy types result in reduced costs or capping or shifting of operating risks. They do not directly boost revenues, and so face potential exclusion in a narrow interpretation of PJM’s materiality test.

In contrast, PJM’s filing, including its definition of actionable subsidies and the examples it provides to illustrate policies of concern, capture purchase requirements (such as RPS) quite granularly.

The final category in Table 1 involves environmental externalities. Power resources differ widely in the environmental and health impacts they cause, though the PJM filing is largely silent on the topic. PJM mentions a preference for a separate system of pricing carbon, and notes that state preferences – including for carbon reduction – would be respected under their Capacity Repricing proposal (PJM 2018: 54, 55). However, given the degree to which actionable subsidies are primarily instruments trying to move the markets towards lower carbon, more focus on this issue would have been beneficial.

Addressing externalities such as pollution or health effects through market instruments is a well-recognized strategy in environmental economics. Taxing the pollutant is a first-best strategy; regulation or other approaches such as subsidies to pollution-reducing substitutes (e.g., an RPS) are less optimal. But broadly, subsidies to address externalities can improve market efficiency if they are done properly (policy design matters with these interventions, and there are more- and less-efficient ways to underwrite pollution reduction). It is a mistake to “treat externality payments like distortive, rent-seeking subsidies that simply provide financial aid to a group of producers without being directly tied to a quantifiable external benefit” (Bialke and Unel 2018: 11).
### Table 1. Capture of Key Subsidy Mechanisms in PJM’s Actionable Subsidy Definition

<table>
<thead>
<tr>
<th>Mechanisms of Value Transfer to Energy Sector¹</th>
<th>How Characterized in PJM FERC Filing and State Action Listing?²</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Direct transfer of funds</strong></td>
<td></td>
</tr>
<tr>
<td>Direct spending</td>
<td><strong>Filing:</strong> Material payments</td>
</tr>
<tr>
<td>Direct budgetary outlays for an energy-related purpose.</td>
<td><strong>CCPPSTF:</strong> 8. Grant Programs</td>
</tr>
<tr>
<td></td>
<td><strong>Potential Gaps:</strong> Energy-relevant activities by the state, rather than through grants to a private party.</td>
</tr>
<tr>
<td><strong>Research and development</strong></td>
<td><strong>Filing:</strong> Material payments</td>
</tr>
<tr>
<td>Partial or full government funding for energy-related research and development.</td>
<td><strong>CCPPSTF:</strong> 8. Grant programs</td>
</tr>
<tr>
<td></td>
<td><strong>Potential Gaps:</strong> None. R&amp;D affects costs of future resources; unlikely to be material to current bidding.</td>
</tr>
<tr>
<td><strong>Tax revenue forgone</strong></td>
<td></td>
</tr>
<tr>
<td>Special tax levies or exemptions for energy-related activities, including production or consumption; includes acceleration of tax deductions relative to standard treatment.</td>
<td><strong>Filing:</strong> Concessions or rebates</td>
</tr>
<tr>
<td></td>
<td><strong>CCPPSTF:</strong> 9. Tax incentives</td>
</tr>
<tr>
<td></td>
<td><strong>Potential Gaps:</strong></td>
</tr>
<tr>
<td></td>
<td>‐Workgroup description focuses on tax exemptions and tax credits. There is another whole class of support through more rapid deductions (generating a time-value benefit) and organizational structures (such as Master Limited Partnerships) that are not being picked up.</td>
</tr>
<tr>
<td></td>
<td>‐At present the inventories are not capturing the pass-through of federal subsidies into the state tax code that often happens by default.</td>
</tr>
<tr>
<td></td>
<td>‐Consistent data gaps regarding artificially low extraction tax rates relative to other jurisdictions, and county or municipal tax subsidies.</td>
</tr>
<tr>
<td></td>
<td>‐Aggregate revenue loss data does not always translate easily into tax subsidy estimates at the facility level.</td>
</tr>
<tr>
<td><strong>Other government revenue forgone</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Access</strong></td>
<td><strong>Filing:</strong> Potentially captured via inclusion of “concessions”.</td>
</tr>
<tr>
<td>Policies governing the terms of access to domestic onshore and offshore resources (e.g., leasing auctions, royalties, production sharing arrangements).</td>
<td><strong>CCPPSTF:</strong> Not captured.</td>
</tr>
<tr>
<td></td>
<td><strong>Potential Gaps:</strong></td>
</tr>
<tr>
<td></td>
<td>‐Non-competitive lease tenders on public land; royalty reductions; state rules allowing royalty-free flaring, venting, or on-site use of extracted minerals on public or private leases.</td>
</tr>
<tr>
<td><strong>Information</strong></td>
<td><strong>Filing:</strong> Provision of free information could fall under “concessions”.</td>
</tr>
<tr>
<td>Provision of market-related information that would otherwise have to be purchased by private market participants.</td>
<td><strong>CCPPSTF:</strong> Not captured.</td>
</tr>
<tr>
<td></td>
<td><strong>Potential Gaps:</strong></td>
</tr>
<tr>
<td></td>
<td>‐Examples would include geological surveys for mineral location or seismic risks to energy infrastructure; or data and statistics collection of relevance to producers.</td>
</tr>
<tr>
<td>Mechanisms of Value Transfer to Energy Sector&lt;sup&gt;1&lt;/sup&gt;</td>
<td>How Characterized in PJM FERC Filing and State Action Listing?&lt;sup&gt;2&lt;/sup&gt;</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td><strong>Transfer of risk to government</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Lending and credit</strong>&lt;br&gt;Below-market provision of loans or loan guarantees for energy-related activities.</td>
<td><strong>Filing:</strong> Potentially captured under concessions or subsidies categories.&lt;br&gt;<strong>CCPPSTF:</strong> 7. Loan programs.&lt;br&gt;<strong>Potential Gaps:</strong>&lt;br&gt;- PJM excludes broader credit programs not stated as for energy; in practice, powerful industries within a state will capture large portion of more general loan programs as well.&lt;br&gt;- Advanced Cost Recovery or CWIP schemes act as interest-free loans from customers to utilities, and would fit well within this category. These were included in CCPPSTF discussion documents, though ultimately excluded.</td>
</tr>
<tr>
<td><strong>Government ownership</strong>&lt;br&gt;Government ownership of all or a significant part of an energy enterprise or a supporting service organization. Often includes high risk or expensive portions of fuel cycle (oil security or stockpiling, ice breakers for Arctic fields).</td>
<td><strong>Filing:</strong> Definition broad enough to potentially incorporate many subsidies that arise with state ownership. However, cooperative and municipal utilities, which are tax-exempt and benefit from other subsidies as well, are excluded as a category.&lt;br&gt;<strong>CCPPSTF:</strong> 10. State takeover, though this is defined quite narrowly.&lt;br&gt;<strong>Potential Gaps:</strong>&lt;br&gt;- Subsidies to publicly-owned utilities.&lt;br&gt;- Federal takeovers of generators (e.g., under DPA) or ownership of key portions of the fuel cycle (e.g., nuclear waste).&lt;br&gt;- State responsibility for ensuring private market safety (e.g., mine inspections) or repairing public ways damaged by energy-related activities (e.g., high ways) with insufficient fees from industry.</td>
</tr>
<tr>
<td><strong>Risk</strong>&lt;br&gt;Government-provided insurance or indemnification at below-market prices.</td>
<td><strong>Filing:</strong> Possibly includible as a concession. No risk examples included by PJM however.&lt;br&gt;<strong>CCPPSTF:</strong> Not captured.&lt;br&gt;<strong>Potential Gaps:</strong>&lt;br&gt;- Federal involvement to cap liability for nuclear accidents and oil spills. States may also have some liability for oil spill cleanup.&lt;br&gt;- Liability risks associated with hydro dam failures is poorly characterized, but likely affects all levels of government.&lt;br&gt;- Legacy liabilities for improperly insured private risks in the past often fall to government; reclamation of abandoned coal mine lands is an example.</td>
</tr>
<tr>
<td><strong>Induced transfers</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Cross-subsidy</strong>&lt;br&gt;Policies that reduce costs to particular types of customers or regions by increasing charges to other customers or regions.</td>
<td><strong>Filing:</strong> Not addressed. Focus on facility-level bid prices.&lt;br&gt;Subsidies via RECs and ZECs often borne entirely by retail customers.&lt;br&gt;<strong>CCPPSTF:</strong> 11. Rate-based cost recovery for certain resources.&lt;br&gt;<strong>Potential Gaps:</strong>&lt;br&gt;- Rate basing cross subsidies in CCPPSTF seemed limited to DSM and efficiency. High cost power resources such as advanced coal may also be rate-based, but would not seem to be included. In contrast, high cost offshore wind would be handled via a REC carve-out, so would be easily measurable and actionable by PJM.&lt;br&gt;- Rate class cross-subsidies probably not relevant to capacity auctions, which focus on unit-level costs.</td>
</tr>
<tr>
<td>Mechanisms of Value Transfer to Energy Sector&lt;sup&gt;1&lt;/sup&gt;</td>
<td>How Characterized in PJM FERC Filing and State Action Listing?&lt;sup&gt;2&lt;/sup&gt;</td>
</tr>
<tr>
<td>------------------------------------------------------</td>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td>-Power trading between ISOs may give rise to some relevant issues if an out-of-region generator is heavily subsidized.</td>
<td></td>
</tr>
</tbody>
</table>
| **Purchase requirements**<sup>*</sup>  
Required purchase of particular energy commodities, such as domestic coal, regardless of whether other choices are more economically attractive. | **Filing:** Captured as “other material support or payments obtained in any state-sponsored or state-mandated process.”  
Used as examples of actionable subsidies.  
Possible gaps: Any federally-implemented purchase mandates (e.g., for coal or nuclear) would be excluded from review. |
| **Regulation**<sup>*</sup>  
Government regulatory efforts that substantially alter the rights and responsibilities of various parties in energy markets or that exempt certain parties from those changes. Distortions can arise from weak regulations, weak enforcement of strong regulations, or over-regulation (i.e. the costs of compliance greatly exceed the social benefits). | **Filing:** Possibly captured as benefits from a “state-mandated process.”  
**CCPPSTF:** Not captured.  
Possible gaps:  
- Regulatory exemptions for particular industries can provide significant cost reductions, but do not seem captured.  
- Regulated returns may provide subsidies to selected infrastructure (e.g., affiliate pipelines), contributing to overbuilding certain segments of the fuel cycle. |
| **Costs of externalities**  
Costs of negative externalities associated with energy production or consumption that are not accounted for in prices. Examples include greenhouse gas emissions and pollutant and heat discharges to water systems. | **Filing:** Not addressed.  
**CCPPSTF:** 2. Emissions tax; 3. Cap-and-trade.  
**Potential Gaps:**  
- Likely to be residual negative externalities not being well captured even after these carbon constraints are incorporated.  
- CCPPSTF shows cap and trade schemes in DE and MD as generating a negative value (i.e., they act as a tax on capacity). Application of capacity pricing or MOPR-Ex rules could possibly be interpreted to add back these fees, making the capacity more competitive in the auctions and obviating state efforts to address environmental externalities of the power source. |

**Sources:**  
<sup>1</sup>Koplow (2017a) and Koplow (2017b).  
5.2. Review of state-level data on energy subsidies

After exclusions for federal support and state or local support targeted at regional redevelopment or plant location, PJM seems to be focusing primarily on purchase mandates as actionable subsidies (PJM 2018; Giacomoni 2018). Such a focus is narrower than the subsidies that had been identified by the CCPSTF (2017). In turn, the subsidies included by the CCPSTF seem not to have incorporated any of the additional interventions flagged in a subsidy “short-list” suggested to the workgroup by CCPSTF member Natural Resources Defense Council (Koplow 2017).

An updated review of available data on state level support indicates that there are many other types of subsidies currently in place. This review incorporated updated information from the Subsidy Tracker database, included in the Appendix as Table A.1. OECD updated its data on US state and federal subsidies to fossil fuels earlier this year as well, adding revenue loss and expenditure information that has become available since its last inventory in 2015. An extract of that data (OECD 2018a) for the PJM region can be found in Table A.2 (tax expenditures) and A.3 (direct outlays). Because OECD has been tracking subsidies for many years, the tables show subsidy values both for recent years and for the 2007-2018 period during which PJM capacity markets have been in place.

The vast majority of entries in the OECD inventory are tax expenditures. Direct expenditures are also captured, and sometimes large as well. However, the direct expenditures relating to fossil fuels in the PJM region are much smaller than the largest tax breaks. The direct spending focuses primarily on safety, inspection and worker training for the coal industry.

Systematic tracking and quantification of subsidies other than direct spending and tax expenditures has been a technical and administrative challenge. The Compendium to the OECD 2018 Subsidy Inventory (OECD 2018b) includes important information on the tracking and valuation of credit support. Credit subsidies are frequently provided by governments to private industry around the world, and the quantification approach discussed is a big step forward in trying to track the value of these supports. In future years, the subsidies associated with individual loan and loan guarantee programs will hopefully start to be tracked routinely. Detailed tracking of subsidies employing still more complex value transfer mechanisms such as natural resource leasing, state-owned enterprises, liability caps, and insurance remain many years off.

Most tax expenditures within the OECD inventory are self-reported by member governments or pulled from state tax expenditure budgets. These sources sometimes have gaps. Tax breaks at the local level such as property taxes may not be included and often don’t show up in state tax expenditure reports either. Pennsylvania’s exemption of gas reserves and related infrastructure from property taxes is an example. Another gap occurs when taxes on energy minerals are well below levels found in other jurisdictions. The state won’t necessarily flag this as a tax subsidy, though clearly the low rate accelerates resource development.
Overall, OECD provides the most comprehensive inventory of national and state subsidies to fossil fuels. However, because it captures only a slice of government support, the disparity between the inventory and the full level of subsidization can sometimes be large. For example, with a surging natural gas industry, Pennsylvania’s lack of severance or property taxes on natural gas is worth more to the industry than any of the PA tax expenditures listed in Table A.2.

This paper does not tally up OECD figures for a few reasons. First, their application to generation potentially bidding into PJM capacity markets will vary by resource. Second, individual provisions serve as useful illustrations for some of the challenges of accurately assessing impacts on capacity auctions. As shown in Table A.2, for example, Pennsylvania has a special sales tax exemption for coal that results in revenue losses of about $125 million per year, and about $1.5 billion over the 2007-2018 period. This does not apply to all fuels, so is clearly a targeted subsidy to the coal fuel cycle. A similar tax expenditure in Kentucky is valued at $34 million for 2018, and almost $700 million during the 2007-2018 period.

In contrast, a Pennsylvania tax exemption for utility sales to residential customers, generated much larger revenue losses, estimated at $458 million in 2018. However, this provision applies to all forms of electricity, natural gas, LPG and fuel oil rather than to a single fuel. The portion flowing to electricity would be of most relevance to PJM capacity auctions; but the point of incidence is consumers. The likely result is that consumers buy more electricity, which would clearly disadvantage demand reduction or efficiency options. But it is not clear that this type of subsidy would tip the scale in any one direction with respect to type of power generation. Extraction subsidies, discussed in the next section, are more likely to do that.

6. Distinctions by Energy Type

PJM’s definition of an actionable subsidy results in greater coverage of supports directed at some types of energy than others. As noted above, this partly results from definitional gaps in the types of policy instruments captured. Additional variability in coverage also results from direct exclusions for particular forms of energy. This section reviews which energy resources are either subject to different rules, or exempt entirely from them; and assesses how these exclusions could affect the neutrality of the proposal.

In addition, and particularly in light of surging production of natural gas and natural-gas fired electricity, the section also addresses the significance of subsidies to upstream or downstream stages of production for key electricity fuel cycles.

6.1. Energy resource neutrality

Power as a byproduct. The proposal excludes a number of resources from consideration for actionable subsidies including energy efficiency and facilities that produce electricity as a
byproduct, such as landfill gas, wood waste, municipal solid waste, black liquor from paper manufacturing, coal mine gas and distillate fuel oil (PJM 2018: 74). PJM argues that “because the economics of energy production and energy market participation for these resources is much more complicated than for a typical Generation Capacity Resource,” and capacity market revenues are not critical for continued operation, they “do not present the price suppression concerns that these market rules address” (PJM 2018: 74).

It is true that power production may be ancillary to the core business for some of these industries and sales may vary somewhat based on production demands. But these are mostly large scale process industries that run every day all day. Because they have other revenue streams, and need to process the wastes for their operations to run smoothly, they might have an incentive to bid low in capacity auctions in order to get at least some capacity revenue for their power operations. It is also the case that the energy conversion process at these facilities is subsidized, sometimes heavily so, both through the federal tax code and via many state renewable portfolio standards. Absent the subsidies, nearly all would continue operations, including power generation. Perhaps the prices in their core industry would rise slightly, though this could actually have environmental benefits. For example, lower prices at landfills and waste-to-energy plants due to subsidies to ancillary energy operations can erode the economics of source reduction and recycling (Koplow 2001), both of which have a better environmental footprint. Whatever the driver, underpricing of these resources in capacity auctions would seem to raise the same concerns with suppressed clearing prices as PJM worried about in other contexts.

Renewables under RPS. In its filing, PJM focuses heavily on renewable purchase mandates (via either RPS or REC systems). The programs currently exist in some form in 11 of the 14 PJM states (including the District of Columbia). Five of the 11 instituted programs prior to the inception of the first capacity market delivery in 2007-08, with the first two in the late 1990s. Three programs were instituted in 2007, and only three states after the capacity market in PJM was already functioning (Barbose 2017; PJM Environmental Information Services 2017; NC Clean Energy Technology Center 2018). In the world of energy subsidies, these are late entrants.

Aside from large scale hydroelectric power projects owned by the federal government, federal subsidies to renewables were near zero in 1989 (Koplow 1993). This started to change only with the introduction of tax breaks, primarily production tax credits for qualified renewable resources, in the federal Energy Policy Act of 1992. In contrast, OECD data in Table A.2 show many large state tax breaks to fossil fuels being introduced in the 1950s, 1960s, and 1970s. Core federal tax breaks to conventional energy are even older. Expensing of intangible drilling costs for oil and gas began in 1913; percentage depletion for oil and gas started in 1926, and for coal in 1932. Liability limits on nuclear accidents took effect in 1957, and responsibility to store and monitor high level nuclear waste was effectively nationalized in 1982 (Koplow 2017).
Nonetheless, PJM analysis indicates the subsidies per MWh in the RPS programs can be large. As such, if resources procured pursuant to these policies were subject to the minimum offer price rule, many would likely fail to clear the capacity market auction. The MOPR-Ex proposal includes an exemption for resources supplying a state-sponsored renewable portfolio standard so long as that RPS program meets certain conditions. PJM’s approach under MOPR-Ex is to grandfather renewables for which at least an RFP was issued prior to December 31, 2018, regardless of the structure of the RPS procurement. Procurements under RPS or REC regimes after that date would continue to be exempt from the minimum offer price rule, despite generating non-market revenues, where they are acquired via a "competitive and non-discriminatory" process. Such a process must include at least three bidders, select winners based on the lowest price, set payments based on the auction clearing price, and treat existing capacity equally to new capacity, among other factors (PJM 2018: 113-114).

There is some question as to how important renewables covered by renewable portfolio standards are to capacity markets in general. A combination of low market share and heavily discounted capacity values result in a fairly small footprint as a capacity supplier. Total installed capacity as of December 31, 2017 was 35.4% coal, 36.8% gas, 18% nuclear, 3.6% oil and 4.8% hydro. Wind, waste-to-energy plants, and solar capacity were only 0.6%, 0.4%, and 0.2% respectively (Monitoring Analytics LLC 2018: 36).

6.2. Relevance of fuel cycle subsidies to electric power capacity markets

Subsidies to fuel extraction and transport; fuel processing (e.g., uranium enrichment or gas plants); reclamation of mine sites and management of wastes; and infrastructure decommissioning all play an important role in the economics of the associated form of electricity. Focusing only on subsidies targeted directly at power production or sale will skew policy oversight away from forms of electricity that have more, or more complicated, upstream and downstream steps. The result will likely be to undercount supports to nuclear, fossil, and hydroelectric power relative to “fuel free” resources such as wind and solar.

It is also likely that at least some of these subsidies are important enough to affect the minimum bid prices in PJM capacity auctions. Indeed, the CCPPSTF did incorporate some subsidies to input fuels in Key Work Assignment #2 of its State Policy Options workbook (CCPPSTF 2017). While this is an indication that some Task Force members viewed them as relevant, upstream subsidies are not addressed directly in the subsequent PJM filing with FERC. Further, the connection between extraction and power plants within particular regions is often a close one -- more than 80% of coal from West Virginia went into electric power production, and most of it within PJM (Figure 1).

---

6 Resources procured pursuant to a voluntary RPS are not grandfathered.
Surging natural gas in Pennsylvania is another example of these important links. PJM capacity auctions in 2010 through 2017 added 50,792 MW of new generation capacity, more than three quarters of which was natural gas (PJM 2018: 10). Gas deliveries for Pennsylvania electric generation increased from 3% of total deliveries in 1997 to 46% in 2015, growing from 20 Bcf to 501 Bcf (Stewart 2017: 5). And despite electric power already being the largest end use sector for natural gas, the transition is not abating: nearly all new planned power capacity is natural gas (Stewart 2017:10). Despite growing in-state consumption, gas exports – including to other PJM states -- are even larger, comprising nearly 77% of total demand in 2015 (Stewart 2017: 18).

**6.2.1. Upstream tax subsidies**

Extraction of hard rock and fuel minerals has been subsidized through the tax code for more than a hundred years. Tax breaks at the federal, state, and local levels remain today. For most industries, investment costs are deducted over the service life of the investment. For oil and gas, many expenses can be deducted from taxable income immediately (intangible drilling costs, tertiary injectants) or more quickly than their service life (geological and geophysical expenses, gathering lines). Acceleration of tax deductions boosts the after-tax income of recipients on a present value basis. The percentage depletion allowance allows mineral firms to deduct investments based on the market value of the mineral rather than the actual investment spending. As a result, deductions can exceed the total amount invested. In many cases, federal tax breaks are mirrored in state statutes, increasing their total value to the firm.
Natural gas production in Pennsylvania is partly supported by sub-national tax breaks as well, particularly regarding severance and property taxes.

Revenue losses to the State or municipal governments can be very large when a state decides to impose no taxes, or much lower rates, on extraction activities relative to surrounding jurisdictions. This is the case in Pennsylvania, one of only two states in the country with no severance tax. Pennsylvania also fully exempts oil and gas (though not coal) reserves and related equipment from local property taxes, something most oil states don’t do.

This information, however, won’t be visible in most of the standard compilations of tax breaks. Property taxes are local, even though statutes on exemptions may have been determined at the state level. And OECD treats each taxing jurisdiction as setting its own baseline, so doesn’t impute “missing” taxes if levels are below average. But industry notices, and drilling activity rises.

Raimi and Newell evaluated the state and local tax structure for the 16 largest oil and gas producing states. Thirteen of these levied property taxes on oil and gas reserves. Pennsylvania does not. Severance taxes compensate states for the permanent extraction of a non-renewable resource. Of the 16 largest producing states, only Pennsylvania and California have no severance taxes. As shown in Table 3 (Raimi and Newell 2016: 5-7), PA and OH had the lowest tax take among the whole sample, at 2.33 and 1.11 percent, respectively in 2013. West Virginia was higher, at 7.79%, though the chart focuses only on oil and gas. WV historically has had a relatively small oil and gas industry and many subsidies to coal instead. The effective rates for 2013 actually represent an improvement: for the period 2004-13 state and local taxes on oil and gas averaged roughly half the 2013 level, at 1.2%, 0.3%, and 4.2% in PA, OH, and WV. Three other PJM states were also in the lowest tier for effective state and local taxation of oil and gas nationally: IL (0.1%), IN (0.9%), and VA (0.0%) (Weber, Wang and Chomas 2015: 27).

Applying the same effective tax rate as Texas in Pennsylvania would have generated roughly $400 million in additional revenue in 2013, even ignoring the continued full property tax exemption on billions of dollars in natural gas infrastructure. The revenue losses to county governments from the oil and gas exemptions to property taxes in Pennsylvania were estimated by a mineral appraiser at $477 million in 2012, rising to $660m in 2013 and nearly $1 billion in 2014 as the surge in investment continued (Kern 2011 in Simeone 2012: 12). Attempts to get updated figures from this analyst were not successful.

In lieu of a severance tax, PA introduced an “impact fee”. It is not really a substitute, however. Severance and property taxes should finance general government operations. To the extent that impact fees are used mostly to offset the impacts that gas drilling has on community budgets through road damage, congestion or higher public safety costs, it is not really contributing to ongoing general state operations as taxes on other sectors of the economy do. The fee should supplement severance and property taxes rather than replacing them. Even so, revenues from Pennsylvania’s impact fee have been falling despite rising production. Between 2014 and 2016, unconventional gas production jumped by 25%, an
increase of more than 1 billion cubic feet; yet impact fees dropped 22%, by near $50 million. Impact fees as a percent of sales is projects to be only 1.2% for 2018, down from 4.5% in 2011 (Polson and Herzenberg 2017: 3,4).

Table 2. Implicit tax breaks to oil and gas extraction in PA and OH appear large

<table>
<thead>
<tr>
<th>State</th>
<th>Severance tax</th>
<th>Other state taxes/fees</th>
<th>Local property taxes</th>
<th>State leases</th>
<th>State share of federal leases</th>
<th>Value of Production</th>
<th>State and local taxes/production value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$millions</td>
<td>$millions</td>
<td>$millions</td>
<td>$millions</td>
<td>$millions</td>
<td>$millions</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td>AK</td>
<td>3,972</td>
<td>107</td>
<td>429</td>
<td>2,80</td>
<td>19</td>
<td>18,900</td>
<td>23.85%</td>
</tr>
<tr>
<td>AR</td>
<td>91</td>
<td>—</td>
<td>42</td>
<td>No data</td>
<td>2</td>
<td>4,400</td>
<td>3.02%</td>
</tr>
<tr>
<td>CA</td>
<td>—</td>
<td>64</td>
<td>505</td>
<td>407</td>
<td>105</td>
<td>21,000</td>
<td>2.71%</td>
</tr>
<tr>
<td>CO</td>
<td>136</td>
<td>—</td>
<td>367</td>
<td>104</td>
<td>99</td>
<td>10,200</td>
<td>4.93%</td>
</tr>
<tr>
<td>KS</td>
<td>123</td>
<td>8</td>
<td>175</td>
<td>1</td>
<td>3</td>
<td>4,900</td>
<td>6.24%</td>
</tr>
<tr>
<td>LA</td>
<td>821</td>
<td>5</td>
<td>202</td>
<td>591</td>
<td>27</td>
<td>17,100</td>
<td>6.01%</td>
</tr>
<tr>
<td>MT</td>
<td>213</td>
<td>—</td>
<td>—</td>
<td>27</td>
<td>21</td>
<td>2,600</td>
<td>8.19%</td>
</tr>
<tr>
<td>ND</td>
<td>2,408</td>
<td>—</td>
<td>—</td>
<td>345</td>
<td>92</td>
<td>24,600</td>
<td>9.79%</td>
</tr>
<tr>
<td>NM</td>
<td>781</td>
<td>21</td>
<td>147</td>
<td>543</td>
<td>460</td>
<td>13,200</td>
<td>7.19%</td>
</tr>
<tr>
<td>OH</td>
<td>3</td>
<td>2</td>
<td>5</td>
<td>0</td>
<td>0</td>
<td>900</td>
<td>1.11%</td>
</tr>
<tr>
<td>OK</td>
<td>494</td>
<td>29</td>
<td>545</td>
<td>90</td>
<td>6</td>
<td>16,500</td>
<td>6.47%</td>
</tr>
<tr>
<td>PA</td>
<td>—</td>
<td>226</td>
<td>—</td>
<td>144</td>
<td>—</td>
<td>9,700</td>
<td>2.33%</td>
</tr>
<tr>
<td>TX</td>
<td>4,485</td>
<td>1</td>
<td>2,475</td>
<td>1,23</td>
<td>17</td>
<td>107,000</td>
<td>6.51%</td>
</tr>
<tr>
<td>UT</td>
<td>53</td>
<td>6</td>
<td>53</td>
<td>69</td>
<td>131</td>
<td>4,300</td>
<td>2.60%</td>
</tr>
<tr>
<td>WV</td>
<td>88</td>
<td>27</td>
<td>72</td>
<td>0</td>
<td>0</td>
<td>2,400</td>
<td>7.79%</td>
</tr>
<tr>
<td>WY</td>
<td>597</td>
<td>—</td>
<td>639</td>
<td>140</td>
<td>472</td>
<td>11,200</td>
<td>11.04%</td>
</tr>
<tr>
<td>Total</td>
<td>14,264</td>
<td>495</td>
<td>5,657</td>
<td>6,50</td>
<td>1,454</td>
<td>268,900</td>
<td>7.59%</td>
</tr>
<tr>
<td>Total, ex AK</td>
<td>10,293</td>
<td>389</td>
<td>5,227</td>
<td>3,700</td>
<td>1,436</td>
<td>250,000</td>
<td>6.36%</td>
</tr>
</tbody>
</table>

Source: Raimi and Newell (2016)

6.2.2. Tax-exempt corporate structures

Firms able to organize their activities in corporate forms that are eligible for lower corporate-level income taxes, or exempt from them entirely, garner a competitive advantage. The oil and gas sector has been particularly adept at doing this. An analysis by the Pennsylvania Budget and Policy Center estimated that as of February 2017, at least 65% of the oil and gas companies in PA were pass-through entities, paying no corporate-level taxation. These firms accounted for “68% of the gas produced in the state and 71% of active wells” (Polson and Hetzenberg 2017: 9). Standard corporations would have incurred a state corporate income tax of nearly 10%.

7 Shareholders of both partnerships and standard C-corporations would also include the individual income taxes, at a rate of just over 3%. The effective rate on pass-throughs would be a bit higher, since paying no taxes on
For the much larger pipeline companies, the corporate structure of choice has been the Master Limited Partnerships (MLP). MLPs are one the very few corporate structures that are both exempt from corporate taxation and are also publicly traded. Issuing shares on the stock market allows these firms to reach the massive scale they need in order to build and operate pipelines, and also to raise capital more cheaply than would be possible otherwise. Not surprisingly, these attributes would be attractive to industries well beyond the oil and gas sector. In fact, during the early 1980s MLPs were expanding so fast across the US economy that Congress worried about huge drops in tax revenues. Their response was to disallow the structure in the Tax Revenue Act of 1987 (Koplow 2013). But their reforms had a few exemptions -- one of which was extractive minerals. Renewable energy firms are not eligible. As of August 2007, 82% of MLPs were in the natural resources segment, of which the vast majority were oil and gas. This subset of MLPs had a market capitalization of $300 billion (MLPA 2017).

MLPs are most active in the mid-stream area, often owning pipelines. Increasingly, private equity firms are also investing in these assets (Morris 2017). A handful of private equity firms are publicly traded as MLPs; many of the rest are privately held partnerships that also pay no corporate income taxes. MLPs are not just pipelines. The new Dominion Cove Point LNG facility is structured as a tax-exempt MLP as well. Its ability to eliminate corporate income taxes is bundled on top of the large property tax abatements it received from Calvert County to reduce the breakeven cost of the plant.

Between 2007 and 2016, FERC has approved pipeline projects involving PA that encompass 12,939 MM cf/day of capacity. An additional 7,292 MM cf/day of capacity was approved in 2017 alone (Simeone 2017). Most of these lines appear to be using tax exempt corporate structures. The dollars are big. Six major pipeline projects within the PJM service area have cost estimates totalling $16.6 billion (McKenna 2017).

6.2.3. Bulk fuel transport

Because coal and natural gas power plants burn so much fuel, subsidies to transport links can artificially reduce plant costs of operation. A combination of very heavy trucks, secondary roads with thinner road beds, and many trips to construct and service fracking operations and coal mine sites, can result in very rapid road wear. While most states have some supplemental fees paid by heavy trucks, these tend to be much lower than the actual damage.

The most detailed work on this issue has been done by the state of Texas. They found road damages exceeded user fees by roughly $2 billion per year. In assessing how various federal and state subsidies to oil affected the ability of oil fields to hit their minimum investment hurdles, the road subsidy to fracking operations in Texas turned out to have the corporate level means that slightly more earnings would pass out to shareholders to then be taxed at the individual level.
largest impact of any state-level support. The subsidy lifted the internal rate of return for
projects in the Permian Basin by nearly 2 percentage points, a significant portion of the project
hurdle rates (Erickson, Downs, Lazarus and Koplow 2017).

Damage from coal hauling is also problematic. A 1981 Kentucky legislative report found
widespread road damage from coal hauling. Estimated costs to repair the damage were
prohibitive. A major cause of the problem: “too many heavy and improperly loaded trucks
have been traveling the state's highways. Laws enacted to protect the roads have been
ignored” (VanArsdall 1981). The problem has persisted. A detailed assessment of the impact
of the coal industry on the Kentucky state budget conducted by the Mountain Association for
Community Economic Development (MACED) found annual road damage costs of more than
$230 million per year in 2006 (Konty and Fry 2009). The scale of this subsidy was an important
driver of MACED’s calculation that, on net, the coal industry cost the state more money than it
brought in. Yet coal trucks continue to be allowed to exceed the weight limits by 10 percent on
Kentucky’s secondary roads, though a 10 percent increase in weight limits can increase the
damages to bridges by a third. (Cheves 2017 and Kentucky House Bill 174).

As noted already, pipeline systems benefit from an array of subsidies including
accelerated depreciation, property tax exemptions, and tax-exempt MLP corporate structures.
They have also had a fairly strong capability to obtain land needed for their lines using the
power of eminent domain, a contentious and often litigated aspect of many of the lines going in
to move gas from the Marcellus. Historically, coal has also moved in significant quantities on
the inland waterway system, where coal and petroleum have long comprised more than half of
the domestic tonnage. Fees on users have been insufficient to finance the inland waterway
system, with more than 90 percent of funding coming from taxpayer subsidy rather than user
fees, according to analysis by the Nicollet Island Coalition (2011). This is significantly higher
than the public subsidy share to roads or rail.

6.2.4 Post-closure cleanup

Extraction sites, fuel processing, power plants, and pipelines all require remediation,
reclamation or decommissioning after the minerals have been removed or the productive life of
a facility ends. These costs often come at a time when company revenue drops sharply and
management may be interested in moving on to other things. To prevent liabilities from
continually being dumped on taxpayers, lawmakers have adopted a variety of approaches to
better protect against financial shortfalls. These include reclamation bonding, mandated
contributions into post-closure trust funds, or user fees on current market participants to help
pay cleanup costs from firms no longer in business. While better than nothing, these
approaches continue to face challenges (see, for example, Davis 2012 and Boomhower 2016).

One measure of the scale of these problems is the backlog on cleaning up old coal
mining sites. Despite some continuing funding of this backlog from an excise tax on coal, the
fee levels are too small and the pace of clean up too slow, to work through the backlog in a
reasonable time frame. Table 4 provides some additional perspective on this. Within PJM,
many states have funded less than half of the reclamation cost to date. Unfunded reclamation liabilities total more than $11 billion within PJM, and the region accounts for more than three-quarters of the reclamation backlog nationally. Allowing bonding and reclamation accruals to be too low artificially reduces the operating costs for those mines. Further, if site owners expect they won’t actually be held to account for the messes they leave behind, they also have far less incentive to make more prudent decisions during operations.

Table 3. PJM dominates unfunded coal mine land reclamation nationally

<table>
<thead>
<tr>
<th>State</th>
<th>Unfunded Cost</th>
<th>Funded Cost</th>
<th>Completed Cost</th>
<th>Total Cost</th>
<th>Unfunded as % of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania</td>
<td>5,044,014,727</td>
<td>217,966,725</td>
<td>644,151,172</td>
<td>5,906,132,623</td>
<td>85.4%</td>
</tr>
<tr>
<td>West Virginia</td>
<td>1,563,561,572</td>
<td>72,272,703</td>
<td>676,163,130</td>
<td>2,311,997,405</td>
<td>67.6%</td>
</tr>
<tr>
<td>Kentucky</td>
<td>474,998,682</td>
<td>93,356,966</td>
<td>574,968,101</td>
<td>1,143,323,749</td>
<td>41.5%</td>
</tr>
<tr>
<td>Virginia</td>
<td>421,442,333</td>
<td>10,793,610</td>
<td>138,930,246</td>
<td>571,166,189</td>
<td>73.8%</td>
</tr>
<tr>
<td>Ohio</td>
<td>359,051,851</td>
<td>4,123,774</td>
<td>171,939,330</td>
<td>535,114,954</td>
<td>67.1%</td>
</tr>
<tr>
<td>Illinois</td>
<td>156,707,030</td>
<td>28,134,366</td>
<td>197,692,405</td>
<td>382,533,801</td>
<td>41.0%</td>
</tr>
<tr>
<td>Indiana</td>
<td>187,453,029</td>
<td>9,256,929</td>
<td>160,824,519</td>
<td>357,534,477</td>
<td>52.4%</td>
</tr>
<tr>
<td>Maryland</td>
<td>64,897,199</td>
<td>2,625,198</td>
<td>42,517,583</td>
<td>110,039,979</td>
<td>59.0%</td>
</tr>
<tr>
<td>Tennessee</td>
<td>44,666,578</td>
<td>1,550,510</td>
<td>47,368,888</td>
<td>93,585,976</td>
<td>47.7%</td>
</tr>
<tr>
<td>Michigan</td>
<td>3,360,000</td>
<td>1,610,000</td>
<td>5,959,034</td>
<td>10,929,034</td>
<td>30.7%</td>
</tr>
<tr>
<td>North Carolina</td>
<td>0</td>
<td>0</td>
<td>163,252</td>
<td>163,252</td>
<td>0.0%</td>
</tr>
<tr>
<td>PJM summary</td>
<td>8,320,153,001</td>
<td>441,690,780</td>
<td>2,660,677,659</td>
<td>11,422,521,440</td>
<td>72.8%</td>
</tr>
<tr>
<td>PJM share of national total</td>
<td>79.3%</td>
<td>78.2%</td>
<td>66.8%</td>
<td>76.0%</td>
<td></td>
</tr>
</tbody>
</table>

Notes: Includes only SMCRA funding, so data should include only coal mining operations. Other funding mechanisms in e-AMLIS include both coal and non-coal sites. Not all AML costs are included, only those potentially addressable under SMCRA. Won’t necessarily tie to state estimates.


7. Case Study: Exemption of Coal from Sales and Use Tax in PA

As the PJM filing is so focused on purchase mandates, it is useful to test a different type of policy to see whether it might also be deemed actionable under PJM’s proposed tests. Quantifying other types of subsidies requires several more steps, but is possible with the right data inputs. Whereas the value of support under an RPS or REC approach is a known amount per unit energy produced, valuing other types of support often requires a baseline against which to compare. In addition, most other forms of subsidy don’t flow directly to generator revenues. Rather, they affect net revenues by reducing cost or risk, or support other parts of the fuel cycle. While time permitted only one test case, running additional screens on a variety of subsidy types in the future would be useful.

Table 4 estimates the impact of Pennsylvania’s exemption of coal from sales and use taxes on the economics of coal-fired power plants. The subsidy value is in the form of “revenue loss,” which measures how much additional revenues the taxing authority would have realized
if not for the special tax breaks. This is a loss to the Treasury, but a gain to the industry that gets to pay lower taxes. The baseline for tax breaks is how much a “normal” taxpayer would have had to pay on a comparable activity. For credit support, it would be what interest rate and loan terms a borrower of the same risk level would have received in the marketplace absent a government guarantee program.

Frequently, subsidy data is available only at an aggregated level. This is nearly always the case with tax breaks since tax returns are kept confidential. Aggregated values need to be allocated to specific beneficiaries based on the details of a particular tax break. Section III of Table 4 shows two adjustments made to the coal tax break: the first is to exclude subsidies flowing to coal that is exported out of state for use. The second is to exclude the portion of the subsidy flowing to coal consumers inside PA, but outside of the power sector. In both of these allocations, the estimates are likely conservative. Nearly three-quarters of coal exports in 2011 went to other PJM states (Pennsylvania Economy League of Greater Pittsburgh 2014), and a portion of industrial users of coal that were excluded from the calculation in Table 4 also generate power and may partake in PJM capacity markets.

After adjustments, the subsidy per MWh ranged from $0.83 to $1.57 per MWh.

The next step is to assess whether that level of support would be actionable under PJM’s proposed rules. Wholesale market revenues for all Pennsylvania coal plants were estimated for the years 2014-2017 on a MWh basis because plant or unit-level revenue data are not publicly available. Energy market revenues were determined based on the average annual day-ahead locational marginal price at the Western Hub, where all but one Pennsylvania coal plant sells power. As with any average, individual coal plants may have higher or lower average energy revenues per MWh than the group, depending on whether they tend to dispatch at peak or off-peak times. This energy market revenue estimate also excludes any uplift payments these generators might have received.

Capacity revenues were determined based on the RTO-wide clearing price in the base residual auction for delivery years 2013/14 through 2017/18. Capacity revenues were converted to per MWh basis for the purpose of this revenue analysis using the average capacity factor for Pennsylvania coal units that had operated in the previous year. This analysis conservatively assumes that all coal units cleared the base residual auction in these years; if any of these units did not clear, their wholesale market revenues would have been lower and therefore the value of the subsidy received as a percentage of revenue would be higher.

As shown in Section IV of Table 4, the tax savings from the subsidy were equivalent to more than 1 percent of revenues in all three years evaluated, reaching a high of 4.4% for 2016. Section V of Table 4 evaluates whether the affected MW of capacity would exceed the 5,000 MW threshold of actionable units system-wide in order for the subsidy adjustments to be acted on by PJM. Assuming all of the active units are clearing the capacity market, the 5,000 MW action threshold would be exceeded by a factor of more than two. This means about half of the PA units could not have cleared capacity markets and the threshold for action would still be
met. Further, the MW test applies PJM-wide. Thus, actionable coal units in PA even well short of 5,000 MW could nonetheless combine with actionable subsidies to other fuels and locations to tip the region over the action threshold.

Under PJM’s proposal as currently formulated, this tax break might be ignored because it doesn’t flow directly to revenues. It might be ignored because the point of impact is on input fuels, rather than directly to the power plant; or because it is more difficult to measure by PJM oversight staff than a simple RPS payment. But it is clear that the subsidy is material, likely part of a fairly big group of material subsidies outside of purchase mandates. Yet, if material subsidies are ignored because they are hard to measure, come in an excluded form from an excluded political jurisdiction, or reduce risks and costs rather than boosting revenues, the PJM system predicated to make wholesale capacity markets better could end up making them worse.

Table 4. Revenue test: Sales tax exemption for Pennsylvania Coal

<table>
<thead>
<tr>
<th>I. Description</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales Tax Exemption for Coal. The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state’s coal-mining industry (OECD 2018a).</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>The tax exemption is provided to coal as an input, not at the point of power generation. This calculation adjusts subsidy amounts to remove the portion flowing to coal that is shipped to other states for consumption, or is used within Pennsylvania at industrial facilities not producing power.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>II. Magnitude of tax expenditure</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>Notes and data sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales tax exemption, bituminous coal in Pennsylvania</td>
<td>84,866,463</td>
<td>116,275,801</td>
<td>117,813,333</td>
<td>OECD, 2018 inventory; allocation to coal types done as a matter of course by OECD. Revenue loss estimates for 2014 seem to have been adjusted upwards in later PA budget cycles, suggesting the subsidy share of revenues for 2014 may be higher than is shown here.</td>
</tr>
<tr>
<td>Sales tax exemption, anthracite coal in Pennsylvania</td>
<td>2,633,537</td>
<td>4,724,199</td>
<td>4,786,667</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>87,500,000</td>
<td>121,000,000</td>
<td>122,600,000</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>III. Adjust subsidy value for reflect portion flowing to power sector inside PA</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A. Coal exports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Export as share of total</td>
<td>8.9%</td>
<td>14.2%</td>
<td>15.3%</td>
</tr>
<tr>
<td>Implied subsidy &quot;export&quot; to other states</td>
<td>7,790,034</td>
<td>17,175,692</td>
<td>18,762,805</td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal within PA</td>
<td>79,709,966</td>
<td>103,824,308</td>
<td>103,837,195</td>
</tr>
<tr>
<td>B. Power sector share of total in-state coal consumption</td>
<td>82.4%</td>
<td>80.4%</td>
<td>82.5%</td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal by PA power producers</td>
<td>65,681,012</td>
<td>83,474,744</td>
<td>85,665,686</td>
</tr>
</tbody>
</table>
Table 4, continued

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>IV. One percent of revenues test</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A. Subsidy magnitude/MWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Estimated net subsidy flowing to consumption of coal by PA power producers</td>
<td>65,681,012</td>
<td>83,474,744</td>
<td>85,665,686</td>
</tr>
<tr>
<td>Coal fired generation in PA, MWh</td>
<td>78,985,629</td>
<td>64,637,233</td>
<td>54,672,030</td>
</tr>
<tr>
<td>Subsidy, $/MWh of coal-fired power produced in PA</td>
<td>0.83</td>
<td>1.29</td>
<td>1.57</td>
</tr>
<tr>
<td><strong>B. Capacity and energy revenues for PA coal-fired generators</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity Revenue per MWh</td>
<td>5.00</td>
<td>8.05</td>
<td>6.78</td>
</tr>
<tr>
<td>Energy Revenue per MWh</td>
<td>51.01</td>
<td>35.82</td>
<td>29.22</td>
</tr>
<tr>
<td>Total Revenue per MWh, PA average</td>
<td>56.01</td>
<td>43.87</td>
<td>36.00</td>
</tr>
<tr>
<td><strong>C. Subsidy exceeds the 1% revenue threshold for all three years</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subsidy/average wholesale revenues</td>
<td>1.5%</td>
<td>2.9%</td>
<td>4.4%</td>
</tr>
<tr>
<td><strong>V. Affected units exceed the 5,000 MW PJM-wide threshold for action</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PA coal clearing capacity auctions that benefit from this subsidy</td>
<td>11,433</td>
<td>10,755</td>
<td>11,478</td>
</tr>
<tr>
<td>System-wide threshold for proposed capacity repricing rules to be implemented, MW</td>
<td>5,000</td>
<td>5,000</td>
<td>5,000</td>
</tr>
<tr>
<td>Ratio of potentially affected coal units/capacity repricing threshold</td>
<td>2.29</td>
<td>2.15</td>
<td>2.30</td>
</tr>
</tbody>
</table>
8. Conclusions

In its proposed tariffs to remove potential distortions caused by subsidies in capacity markets, PJM includes a number of limitations and exclusions that appear to result in unequal evaluation of subsidies across different fuel cycles. This will likely impede PJM’s core objective of ensuring competitive, nondiscriminatory auctions in the wholesale capacity market. Because subsidies flow to all forms of generation, and nearly every upstream and downstream stage of each power-related fuel cycle as well, a comprehensive review process is needed if PJM is to address these subsidies in a neutral way.

- **Blanket exclusion of federal and many state and local subsidies will reduce the accuracy of subsidy screening significantly.** PJM excludes all federal subsidies, and any state or local support that is in place for regional economic development or to convince a plant to locate (or stay) in a particular region. Federal subsidies can be both large and highly targeted to an industrial facility. State and local subsidies excluded on the basis of their stated purpose can also be very large. They may represent multiple state programs, originating from more than one agency – some of which may be excluded and others not based on the PJM proposal. In all of these areas, it is the scale of support rather than the justification for granting it that will drive capacity market distortions.

- **Revenue-based metrics for actionable subsidies need to be broadened to incorporate cost- and risk-reducing subsidies.** Subsidies operate using three main levers: boosting revenues, reducing costs, and reducing the volatility of expected return by absorbing or capping credit, liability, or other operating risks. The PJM proposal, as currently worded, focuses only on revenues and as a result will not treat different power sources equally. If a policy of mitigating subsidies is to be pursued, then the materiality test should shift from 1% of revenues to “a subsidy equal in magnitude to one percent of revenues” to incorporate the broad array of subsidy mechanisms.

- **Purchase mandates are one technique of many that governments use to transfer value to the energy sector; subsidy screening needs to incorporate all of them.** Not every form of electrical power has the same cost structure. Some are capital-intensive, rolling out new technologies, or face long or uncertain build times. Others require complex fuel supply chains, have risks of severe accidents, or significant and complex post-closure concerns. Still others have variability in their ability to produce electricity. As a result of these differences, the importance of particular types of subsidy support varies significantly across fuels, and rules that by definition or effect limit review to a small subset of subsidy approaches will materially disadvantage some energy resources over others.

- **PJM’s current focus almost entirely on purchase mandates will understate the level of subsidies to other forms of energy.** In addition, where interventions are focused on internalizing environmental or health externalities that are not being addressed in other ways, PJM needs to evaluate the impact on efficiency using more than just generator costs of operation.
• **Large subsidies to upstream or downstream fuel cycle steps need to be addressed to determine when a subsidy should be actionable.** These types of supports are most relevant regarding subsidies to coal and natural gas extraction and transport; coal mine land reclamation; large state support to ancillary infrastructure to move or process fuels; or state subsidy for high risk, long-term parts of the nuclear fuel cycle.

• **Subsidy combinations matter.** If there are multiple subsidies flowing to the same beneficiaries that in total exceed PJM’s action threshold of support equal to 1% of revenues, these should be reviewed as a group for action even if individually they don’t hit 1%. Subsidy “stacking” is common across the world, and it is the joint effect of multiple subsidies that will drive the distortions in market behavior.

• **Test case illustrates the importance of a more systematic inclusion of subsidies as potentially subject to PJM action.** A test case relating to tax exemptions for coal in the state of Pennsylvania indicates that more subsidies than just purchase mandates would exceed the PJM’s proposed revenue threshold. Additional analysis would likely illustrate a similar situation in multiple other parts of PJM, though this one example is useful in illustrating why a narrow focus on purchase mandates will be insufficient in addressing potential distortions.
9. Appendix – Subsidy Tables

Table A.1. Subsidies to specific energy facilities within PJM Interconnection (showing >$20 million only)

<table>
<thead>
<tr>
<th>Company</th>
<th>Location</th>
<th>Project Description</th>
<th>Year of Decision</th>
<th>Subsidy Value (multiple years)</th>
<th>Program Name</th>
<th>Awarding Agency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royal Dutch Shell</td>
<td>Pennsylvania</td>
<td>ethane cracker plant</td>
<td>2012</td>
<td>$1,650,000,000</td>
<td>special state tax credits</td>
<td>state legislature</td>
</tr>
<tr>
<td>Clean Coal Power Operations (KY) LLC</td>
<td>Kentucky</td>
<td>coal to diesel plant (inactive)</td>
<td>2008</td>
<td>$550,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Dominion Cove Point LLC</td>
<td>Maryland</td>
<td>expansion of a facility for the liquefaction of natural gas</td>
<td>2013</td>
<td>$506,000,000</td>
<td>Payment in Lieu of Tax</td>
<td>Calvert County Board of County Commissioners</td>
</tr>
<tr>
<td>Hemlock Semiconductor (controlled by Dow Corning)</td>
<td>Michigan</td>
<td>solar cell and semiconductor manufacturing</td>
<td>2008</td>
<td>$372,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Holtec International</td>
<td>New Jersey</td>
<td>small nuclear reactors manufacturing facility</td>
<td>2014</td>
<td>$260,000,000</td>
<td>Grow New Jersey Assistance Program</td>
<td>Economic Development Agency</td>
</tr>
<tr>
<td>Kentucky Syngas, LLC</td>
<td>Kentucky</td>
<td>Coal to gas plant</td>
<td>2007</td>
<td>$250,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Dow Kokam (previously known as KD Advanced Battery Group)</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2009</td>
<td>$194,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Marathon Petroleum</td>
<td>Michigan</td>
<td>refinery expansion</td>
<td>2007</td>
<td>$186,000,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Cash Creek Generation</td>
<td>Kentucky</td>
<td>coal gasification plant</td>
<td>2008</td>
<td>$150,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Company</td>
<td>Location</td>
<td>Project Description</td>
<td>Year of Decision</td>
<td>Subsidy Value (multiple years)</td>
<td>Program Name</td>
<td>Awarding Agency</td>
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</tr>
<tr>
<td>Dow Chemical</td>
<td>Michigan</td>
<td>manufacturing facilities for renewable energy materials</td>
<td>2010</td>
<td>$129,300,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>fortu PowerCell, Inc.</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$112,600,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$100,000,000</td>
<td>Michigan Business Tax Battery Credit</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>United Solar Ovonic (no longer operating)</td>
<td>Michigan</td>
<td>solar panel production facility</td>
<td>2008</td>
<td>$96,900,000</td>
<td>multiple</td>
<td>multiple</td>
</tr>
<tr>
<td>Secure Energy Kentucky</td>
<td>Kentucky</td>
<td>coal-to-liquid gasification plant</td>
<td>2011</td>
<td>$85,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Coal Synthetics (inactive)</td>
<td>Kentucky</td>
<td>coal-to-gas plant</td>
<td>2008</td>
<td>$80,000,000</td>
<td>Incentives for Energy Independence Act</td>
<td>Kentucky Economic Development Finance Authority</td>
</tr>
<tr>
<td>Marathon Petroleum</td>
<td>Ohio</td>
<td>oil company headquarters</td>
<td>2011</td>
<td>$78,500,000</td>
<td>multiple</td>
<td>Department of Development</td>
</tr>
<tr>
<td>Marathon Petroleum Corporation</td>
<td>Ohio</td>
<td>oil company headquarters</td>
<td>2011</td>
<td>$72,128,036</td>
<td>Job Retention Tax Credit</td>
<td>Department of Development</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>Hybrid and electric car batteries</td>
<td>2010</td>
<td>$42,000,000</td>
<td>Michigan Business Tax Battery Credit</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>Company</td>
<td>Location</td>
<td>Project Description</td>
<td>Year of Decision</td>
<td>Subsidy Value (multiple years)</td>
<td>Program Name</td>
<td>Awarding Agency</td>
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</tr>
<tr>
<td>NRG Energy Inc.</td>
<td>New Jersey</td>
<td>facility expansion</td>
<td>2013</td>
<td>$37,520,000</td>
<td>Grow New Jersey Assistance Program</td>
<td>Economic Development Authority</td>
</tr>
<tr>
<td>Dow Kokam Advanced Battery Group</td>
<td>Michigan</td>
<td>advanced battery manufacturing</td>
<td>2010</td>
<td>$29,007,000</td>
<td>MEGA (Michigan Economic Growth Authority) Tax Credits</td>
<td>Michigan Economic Development Corporation</td>
</tr>
<tr>
<td>Plains and Eastern Clean Line LLC</td>
<td>Tennessee</td>
<td>purchase renewable wind energy, construct direct current electric transmission line that terminates at a new converter station and then ties into the Tennessee Valley Authority network</td>
<td>2014</td>
<td>$23,369,368</td>
<td>Shelby County PILOT Agreements</td>
<td>Economic Development Growth Engine</td>
</tr>
</tbody>
</table>

Source: Good Jobs First Subsidy Tracker Database, extract 27 April 2018.
### Table A.2. Estimated Revenue Lost to State Treasuries in PJM Region from State-level Tax Expenditures Provided to Fossil Fuels

<table>
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</thead>
<tbody>
<tr>
<td><strong>Sales Tax Exemption for Residential Utilities.</strong> Exemption includes sales of electricity, natural gas, LPG, and fuel oil to residential users in Pennsylvania from the sales and use tax normally levied on sales of most goods and services in that state. It is meant to ensure that households retain access to basic services or commodities. Allocated to fuels based on state consumption data.</td>
<td>NR</td>
<td>END</td>
<td>ELECTR</td>
<td>PA</td>
<td>416,000,000</td>
<td>423,300,000</td>
<td>440,300,000</td>
<td>458,400,000</td>
<td>4,987,500,000</td>
</tr>
<tr>
<td><strong>Sales Tax Exemption for Coal.</strong> The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state’s coal-mining industry.</td>
<td>NR</td>
<td>END</td>
<td>BITCOAL</td>
<td>PA</td>
<td>116,275,801</td>
<td>117,813,333</td>
<td>119,254,768</td>
<td>122,233,735</td>
<td>1,473,079,772</td>
</tr>
<tr>
<td><strong>Sales Tax Exemption for Energy and Energy Producing Fuels.</strong> All energy and energy-producing fuels used in manufacturing, processing, mining, or refining and any related distribution, transmission, and transportation services, to the extent that the cost of the energy or energy-producing fuels used exceeds 3% of the cost of production, are exempt from Kentucky’s sales and use tax.</td>
<td>1960</td>
<td>INDUS</td>
<td>NATGAS</td>
<td>KY</td>
<td>36,376,202</td>
<td>36,165,121</td>
<td>37,290,884</td>
<td>38,557,367</td>
<td>321,894,747</td>
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</tr>
<tr>
<td>Coal Used in the Manufacture of Electricity. Special sales and use tax exemption on the purchase of coal used to generate electricity; coal consistently ranks as the top fuel used for electricity generation in Kentucky, with more than 90% of the State's electricity generated in coal-fired power plants.</td>
<td>1960</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>KY</td>
<td>55,000,000</td>
<td>33,800,000</td>
<td>35,900,000</td>
<td>34,100,000</td>
<td>667,402,000</td>
</tr>
<tr>
<td>Coal Refuse Energy and Reclamation Tax Credit. Credits may be awarded at a rate of $4 per 2,000 pounds of qualified coal refuse, capped at 22.2 percent of the available budget allocation per fiscal year. Credit may be used against personal income tax, corporate net income tax, capital stock and franchise tax, bank shares tax, title insurance company shares tax, insurance premiums tax, and mutual thrift institutions tax liabilities.</td>
<td>2016</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>7,207,178</td>
<td>9,609,570</td>
<td>9,609,570</td>
<td>26,426,318</td>
</tr>
<tr>
<td>Sales Tax Exemption for Energy and Energy Producing Fuels. All energy and energy-producing fuels used in manufacturing, processing, mining, or refining and any related distribution, transmission, and transportation services, to the extent that the cost of the energy or energy-producing fuels used exceeds 3% of the costs of production, are exempt from Kentucky's sales and use tax.</td>
<td>1960</td>
<td>INDUS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>7,779,806</td>
<td>7,734,662</td>
<td>7,975,430</td>
<td>8,246,294</td>
<td>89,460,708</td>
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<tr>
<td>Sales Tax Exemption for Energy and Energy Producing Fuels. All energy and energy-producing fuels used in manufacturing, processing, mining, or refining and any related distribution, transmission, and transportation services, to the extent that the cost of the energy or energy-producing fuels used exceeds 3% of the costs of production, are exempt from Kentucky’s sales and use tax.</td>
<td>1960</td>
<td>INDUS</td>
<td>LPG</td>
<td>KY</td>
<td>6,706,984</td>
<td>6,668,065</td>
<td>6,875,632</td>
<td>7,109,144</td>
<td>66,290,137</td>
</tr>
<tr>
<td>Sales Tax Exemption for Coal. The purchase or use of coal in Pennsylvania is exempt from the sales and use tax normally levied on sales of most goods and services in that state; introduced to encourage the consumption of coal and sustain employment in the state’s coal-mining industry.</td>
<td>NR</td>
<td>END</td>
<td>ANTCOAL</td>
<td>PA</td>
<td>4,724,199</td>
<td>4,786,667</td>
<td>4,845,232</td>
<td>4,966,265</td>
<td>51,620,228</td>
</tr>
<tr>
<td>Excess of Percentage over Cost Depletion. Extends the corresponding federal provision for percentage depletion to Kentucky’s own corporation tax system. Allows companies to calculate deductions from their taxable income based on a percentage of the gross income derived from mining or drilling for natural resources. Under normal income-tax treatment, producers would recover investment costs over time as resources are depleted. In the case of percentage depletion, the sum of</td>
<td>1954</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>3,058,703</td>
<td>2,893,368</td>
<td>2,893,368</td>
<td>2,893,368</td>
<td>31,285,793</td>
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<tr>
<td>deductions can exceed the actual cost of investment.</td>
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</tr>
<tr>
<td><strong>Coal Incentive Tax Credit.</strong> Can be claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
<td>2000</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>KY</td>
<td>3,389,374</td>
<td>2,893,368</td>
<td>2,810,700</td>
<td>2,728,033</td>
<td>21,781,575</td>
</tr>
<tr>
<td><strong>Railroad Improvement Tax Credit.</strong> Tax credit to certain railroad companies against the costs incurred for maintenance and improvement, and for railroad expansion or upgrades to accommodate the transport of fossil energy or biomass resources.</td>
<td>2009</td>
<td>TRANS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>2,700,000</td>
<td>2,600,000</td>
<td>2,500,000</td>
<td>11,100,000</td>
</tr>
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</tr>
<tr>
<td>Thin Seam Tax Credit. Allows mining companies operating in the state to get a tax credit for coal mined from thin seams or from areas with a high overburden ratio. The credit is on a sliding scale from 2.25% to 3.75% of the value of the severed coal and based on the thickness of the seam, the ratio of overburden removed to coal severed, and the sulphur content of the coal.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>1,901,356</td>
<td>1,818,688</td>
<td>1,901,356</td>
<td>1,901,356</td>
<td>18,497,073</td>
</tr>
<tr>
<td>Coal Incentive Tax Credit. Can be claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
<td>2000</td>
<td>GENER</td>
<td>COKCOAL</td>
<td>KY</td>
<td>686,901</td>
<td>586,379</td>
<td>569,625</td>
<td>552,871</td>
<td>4,677,064</td>
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<tr>
<td>Program Description</td>
<td>Start Date</td>
<td>Fuel Cycle Stage</td>
<td>Fuel Category*</td>
<td>State</td>
<td>2015 Revenue (Loss)</td>
<td>2016 Revenue (Loss)</td>
<td>2017 Revenue (Loss)</td>
<td>2018 Revenue (Loss)</td>
<td>Revenue Loss during Period of PJM Capacity Auctions (2007-18)</td>
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</tr>
<tr>
<td><strong>Coal Refuse Energy and Reclamation Tax Credit.</strong> Credit may be awarded at a</td>
<td>2016</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>PA</td>
<td>-</td>
<td>292,822</td>
<td>390,430</td>
<td>390,430</td>
<td>1,073,682</td>
</tr>
<tr>
<td>rate of $4 per 2,000 pounds of qualified coal refuse, capped at 22.2 percent of</td>
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<tr>
<td>the available budget allocation per fiscal year. Credit may be used against</td>
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<tr>
<td>personal income tax, corporate net income tax, capital stock and franchise tax,</td>
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<tr>
<td>bank shares tax, title insurance company shares tax, insurance premiums tax, and</td>
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<tr>
<td>mutual thrift institutions tax liabilities.</td>
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</tr>
<tr>
<td><strong>Excess of Percentage over Cost Depletion.</strong> Extends the corresponding federal</td>
<td>1954</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>21,411</td>
<td>20,253</td>
<td>20,253</td>
<td>20,253</td>
<td>358,291</td>
</tr>
<tr>
<td>provision for percentage depletion to Kentucky’s own corporation tax system.</td>
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<tr>
<td>Allows companies to calculate deductions from their taxable income based on a</td>
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<tr>
<td>percentage of the gross income derived from mining or drilling for natural resources. Under normal income-tax treatment, producers would recover investment costs over time as resources are depleted. In the case of percentage depletion, the sum of deductions can exceed the actual cost of investment.</td>
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<tr>
<td>Coal Incentive Tax Credit. Can be claimed by any eligible electric-power company or entity operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities. The tax credit amounts to USD 2 per short ton of coal purchased in excess of the amounts purchased in a reference year. The eligible quantities of coal must be used to generate electric power or used as feedstock in an alternative fuel facility or a gasification facility.</td>
<td>2000</td>
<td>GENER</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>23,725</td>
<td>20,253</td>
<td>19,675</td>
<td>19,096</td>
<td>243,360</td>
</tr>
<tr>
<td>Thin Seam Tax Credit. Allows mining companies operating in the state to get a tax credit for coal mined from thin seams or from areas with a high overburden ratio. The credit is on a sliding scale from 2.25% to 3.75% of the value of the severed coal and based on the thickness of the seam, the ratio of overburden removed to coal severed, and the sulphur content of the coal.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>13,309</td>
<td>12,731</td>
<td>13,309</td>
<td>13,309</td>
<td>215,181</td>
</tr>
<tr>
<td>Sales Tax Incentive for Alternative Fuel or Gasification Facilities. Exempts eligible taxpayers from the sales taxes paid on tangible personal property used in the process of constructing an alternative fuel or gasification facility (all related to coal).</td>
<td>2008</td>
<td>REFIN</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>4,305,929</td>
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<tr>
<td><strong>Sales Tax Incentive for Alternative Fuel or Gasification Facilities.</strong> Exempts eligible taxpayers from the sales taxes paid on tangible personal property used in the process of constructing an alternative fuel or gasification facility (all related to coal).</td>
<td>2008</td>
<td>REFIN</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>70,393</td>
</tr>
<tr>
<td><strong>Coal Transportation Expense.</strong> Values used for calculating taxes and royalties due allow deduction of transportation expenses incurred to move coal from mine to a processing plant, loading point, or customer.</td>
<td>1978</td>
<td>TRANS</td>
<td>BITCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>110,637,409</td>
</tr>
<tr>
<td><strong>Coal Transportation Expense.</strong> Values used for calculating taxes and royalties due allow deduction of transportation expenses incurred to move coal from mine to a processing plant, loading point, or customer.</td>
<td>1978</td>
<td>TRANS</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,521,009</td>
</tr>
<tr>
<td><strong>Gross-Receipts Tax Exemption for Sales of Natural Gas.</strong> Sales of natural gas by regulated companies in Pennsylvania are exempted from the gross receipts tax normally levied on most sales by utilities. This exemption was introduced in January 2000 to reduce the gas bills of Pennsylvania consumers.</td>
<td>2000</td>
<td>END</td>
<td>NATGAS</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>108,000,000</td>
</tr>
<tr>
<td><strong>Reduced Tax for Thin-Seamed Coal.</strong> Coals seams with a thickness of less than 45 inches pay a 1-2% severance tax instead of the normal rate of 5%. Only new underground mines may</td>
<td>1997</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>WV</td>
<td>60,000,000</td>
<td>60,000,000</td>
<td>-</td>
<td>-</td>
<td>516,000,000</td>
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<tr>
<td><strong>Coalbed Methane Exemption.</strong> WV exempt coalbed-methane wells placed in service after 1 January 2000 from the state’s severance tax (5% of the gross value of severed coalbed methane). This exemption can be used for five consecutive years and is meant to encourage the capture and use of coalbed methane. Subsequent legislation added a provision making the exemption only applicable to coalbed-methane wells placed in service before 1 January 2009. Qualifying wells can, however, continue to use their five year exemption provided they were placed in service before 1 January 2009.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>WV</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>15,000,000</td>
</tr>
<tr>
<td><strong>Exclusion of Low Volume Oil &amp; Gas Wells.</strong> WV wells producing less than one-half barrel per day or less than 5,000 cubic feet per day are exempted from the state’s severance tax (5% of the gross value of severed oil and gas). A similar exemption also applies to natural gas provided for free by producers to surface land owners.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>WV</td>
<td>4,373,252</td>
<td>4,373,252</td>
<td>-</td>
<td>-</td>
<td>49,313,831</td>
</tr>
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<tr>
<td>Exclusion of Low Volume Oil &amp; Gas Wells. WV wells producing less than one-half barrel per day or less than 5,000 cubic feet per day are exempted from the state’s severance tax (5% of the gross value of severed oil and gas). A similar exemption also applies to natural gas provided for free by producers to surface land owners.</td>
<td>2000</td>
<td>EXTRACT</td>
<td>CRUDEOIL</td>
<td>WV</td>
<td>126,748</td>
<td>126,748</td>
<td>-</td>
<td>-</td>
<td>1,686,169</td>
</tr>
<tr>
<td>Industrial Expansion and Revitalization Credit. Eligible companies operating in West Virginia with a tax credit worth 10% of certain qualifying investment expenditures in both real and tangible property. Since 2003, has applied only to power sector; state data indicates it is mostly going to coal utility modernization and pollution control.</td>
<td>NR</td>
<td>GENER</td>
<td>BITCOAL</td>
<td>WV</td>
<td>45,000,000</td>
<td>45,000,000</td>
<td>-</td>
<td>-</td>
<td>270,000,000</td>
</tr>
<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>NATGAS</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
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<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>CRUDEOIL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Realty-Transfer Tax Exemption for Resource Leases. Transfers of leases for the extraction of oil, natural gas, coal, and minerals in Pennsylvania are exempted from the state’s realty transfer tax. The realty transfer tax is a stamp tax levied on all transactions of interests in real estate. No data located by OECD.</td>
<td>NR</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Coal Waste Removal Tax Credit. In effect through 2012. Tax credit encouraged investment in facilities that produce fuels from coal and coal dust. OECD was unable to get data, though budget documents indicated only a few facilities benefits. Credit was capped at $18m/year.</td>
<td>1971</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>PA</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No data</td>
</tr>
<tr>
<td>Sales of Electricity. The West Virginia Tax Code exempts the sales of electricity from the Consumers Sales and Service Tax due to the Business and Occupation Tax on businesses providing electricity.</td>
<td>NR</td>
<td>END</td>
<td>ELECTR</td>
<td>WV</td>
<td>150,000,000</td>
<td>150,000,000</td>
<td>-</td>
<td>-</td>
<td>1,370,700,000</td>
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<td>----------------------------------------------------------</td>
</tr>
</tbody>
</table>

*Where a provision benefits multiple fossil fuels, OECD will include allocated shares for each one as separate line items in their database in order to facilitate fuel-specific totals.

**Key:** Start Date: “NR” = not reported within OECD database; Fuel Cycle Stage: “EXTRACT” = extraction; “GENER” = power generation; “END” = end-use/point of consumption.

**Source:** Data extract from Organisation for Economic Cooperation and Development, Inventory of Support Measures for Fossil Fuels, 2018.
# Table A.3. Direct Outlays to Fossil Fuels by State Governments in the PJM Region

<table>
<thead>
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<tr>
<td>Department for Energy Development and Independence</td>
<td>2006</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>7,777</td>
<td>7,850</td>
<td>7,182</td>
<td>7,229</td>
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<td>2006</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>1,111,053</td>
<td>1,121,469</td>
<td>1,026,071</td>
<td>1,032,684</td>
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<td>Department for Energy Development and Independence</td>
<td>2006</td>
<td>EXTRACT</td>
<td>COKCOAL</td>
<td>KY</td>
<td>225,169</td>
<td>227,280</td>
<td>207,947</td>
<td>209,287</td>
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<td>Coal Academy Mining Workforce Development</td>
<td>2006</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>17,360</td>
<td>17,360</td>
<td>17,360</td>
<td>17,360</td>
<td>353,308</td>
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<td>2006</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>2,480,030</td>
<td>2,480,030</td>
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<td>2,480,030</td>
<td>30,029,712</td>
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<tr>
<td>Coal Academy Mining Workforce Development</td>
<td>2006</td>
<td>EXTRACT</td>
<td>COKCOAL</td>
<td>KY</td>
<td>502,610</td>
<td>502,610</td>
<td>502,610</td>
<td>502,610</td>
<td>5,616,977</td>
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<td>Mine Safety and Licensing</td>
<td>NR</td>
<td>EXTRACT</td>
<td>ANTCOAL</td>
<td>KY</td>
<td>63,092</td>
<td>60,855</td>
<td>58,347</td>
<td>58,071</td>
<td>1,487,586</td>
</tr>
<tr>
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<td>NR</td>
<td>EXTRACT</td>
<td>BITCOAL</td>
<td>KY</td>
<td>9,013,140</td>
<td>8,693,661</td>
<td>8,335,297</td>
<td>8,295,865</td>
<td>121,561,614</td>
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<td>Mine Safety and Licensing</td>
<td>NR</td>
<td>EXTRACT</td>
<td>COKCOAL</td>
<td>KY</td>
<td>1,826,630</td>
<td>1,761,884</td>
<td>1,689,256</td>
<td>1,681,265</td>
<td>23,111,555</td>
</tr>
</tbody>
</table>

References


Konty, Melissa Frye and Bailey, Jason (2009). The Impact of Coal on the Kentucky State Budget, (Berea, KY: Mountain Association for Community Economic Development).


Polson, Diana and Herzenberg, Stephen (2017). “It’s Time for a Real Severance Tax in Pennsylvania: While Gas Production Continues to Rise, Drillers’ Impact Fee and
Corporate Tax Payments Remain Low,” (Harrisburg, PA: Pennsylvania Budget and Policy Center), 7 June.


Smith, Samantha (2017). Talking points for press conference announcing the deal with CEIP, released as part of a FOIA submittal to the office of Governor Jim Justice of WV, 13 November.


Koplow Biography
Doug Koplow

**Doug Koplow** is the founder of Earth Track in Cambridge, MA ([www.earthtrack.net](http://www.earthtrack.net)). For nearly 30 years, his work has focused on government subsidization of natural resources, primarily in the energy sector.

Working collaboratively with environmental groups, government officials, and international agencies such as the World Bank and the Organisation for Economic Cooperation and Development, he has helped to improve subsidy measurement and to document the pervasive reach and enormous scale of energy subsidies. Redirecting these hundreds of billions of dollars per year in subsidies is increasingly recognized as an important lever for reducing poverty, transitioning to cleaner energy, and addressing climate change.

Doug’s most recent work has focused on subsidies to fossil fuels and nuclear power. He holds an MBA from the Harvard Business School and a BA in economics from Wesleyan University.
Gramlich Affidavit
I. Introduction

I am an independent consultant specializing in wholesale electricity markets and transmission policy. I have served as a Senior Economist at PJM Interconnection LLC responsible for monitoring its capacity markets, Economic Advisor to a FERC Chairman, and as Senior Vice President of the American Wind Energy Association. My biography can be found at https://gridstrategiesllc.com/about/.

I was asked to assess the two PJM capacity market reform proposals, and compare them to FERC economic policy standards.

II. Just and Reasonable Rates are Based on Prices Resulting from the Interaction of All Supply and Demand, In the Absence of Market Power

It is longstanding Commission policy to have prices set according to the interaction of supply and demand, where market power is absent or mitigated. This has been the general
framework established by FERC and the courts since electricity competition began in the early 1990s.\textsuperscript{1,2,3} This Commission policy has a firm basis in sound economic policy where competition can be relied upon to produce efficient prices as long as market failures are either not present or have been mitigated. There is nothing more fundamental in economics than setting prices where supply and demand intersect.

Market failures, particularly market power, can result in supply and demand setting prices that are not competitive, so policy makers including the Commission often seek to improve efficiency through targeted interventions that correct the market failure. Since competition in electricity began, the Commission has approved a variety of measures to address market power. For example, forms of Reliability Must-Run Agreements exist in each RTO or ISO market to address situations where a specific generator has local market power for services such as providing voltage support at that location. Each RTO/ISO has rules related to economic and physical withholding. These were all developed and approved based on findings of a potential for market power to be exercised. RTOs and ISOs themselves were created largely to mitigate the vertical market power that exists when the transmission system is operated by the same corporate entity as a player in the generation market. Beyond situations of market power, the Commission has relied on competitive forces without further intervention to manage bids or prices.

\textsuperscript{1} Elizabethtown Gas Co. v. FERC, 10 F.3d. 866, 870 (D.C. Cir. 1993).
\textsuperscript{2} “[I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment.” \textit{Tejas Power Corp. v. FERC}, 908 F.2d 998, 1004 (D.C. Cir. 1990).
Previous specific instances of PJM and other RTO/ISO mitigation of state policy has been deemed just and reasonable on the basis of mitigating market power. The Commission’s original order approving the minimum offer prices rule (“MOPR”) in PJM stated, “The Commission finds the Minimum Offer Price Rule a reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self-supply.”\textsuperscript{4} The Commission’s later approvals of changes to MOPR stated, “We begin our analysis with a review of the MOPR’s underlying objectives. PJM’s MOPR is a mechanism that seeks to prevent the exercise of buyer-side market power.”\textsuperscript{5} Whether market power was present or absent was also the basis for allowing exemptions to state policy mitigation.\textsuperscript{6}

\textbf{III. No Market Power Has Been Demonstrated or Alleged in this Case}

In contrast to PJM’s original MOPR proposal and later changes to MOPR which relied on demonstrations of market power and Commission findings that it existed and should be mitigated, here there is no such demonstration and nothing on which the Commission could base a finding. There is no section of the filing or affidavits that provide any assessment of market power.

Many of the public policies at issue in this case relate to renewable energy. There is no assessment of whether these policies specifically are exercises of market power. The Commission has found in the past that renewable energy would be very unlikely to be used to exercise buyer side market power, given its lower capacity value and higher prices.\textsuperscript{7} This filing

\textsuperscript{4} PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at P 104 (2006).
\textsuperscript{7} ISO New England Inc. and New England Power Pool Participants Committee, 158 FERC at P 10.
provides no analysis to counter that Commission finding. There is no allegation that the renewable resources developed under these policies are being used to exercise any other form of market power.

IV. No other market failures have been demonstrated in this case to justify intervention

It can be sound economic policy to intervene in markets if there is a workable and efficient remedy to other types of market failure, in addition to market power. Market power is the primary market failure of concern in electricity markets, but other potential market failures include barriers to entry, externalities, public goods, and information asymmetries. PJM does not establish that any of these other market failures exist.

A. PJM makes no demonstration of a barrier to entry

PJM does allege a barrier to entry: “if a material fraction of resources price their capacity offers relying on their selective receipt of subsidies, then: ...competitive entry will face a significant added barrier.” PJM provides an example on pages 29-32 to demonstrate this harm. PJM’s assertions may show harm to competitors, not competition. PJM’s conclusion from its example states: “The real world is more complicated than this simple example, but it serves to illustrate a critical point: the state subsidy program is being underwritten by other participants in the wholesale market.” Whether competitors fare better or worse is not the same as harming the competitive process. PJM states that “It undermines robust competition

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9 PJM filing, at p. 4.
because other sellers cannot compete against a substantial subsidy available only to select
capacity sellers.” This is a claim about competitors, not competition. If the goal were to
protect some sellers’ ability to compete then policies would be needed to shield market sellers
from the effects of low natural gas prices, which are harming the economics of all supply
sources. Clearly that would not be appropriate or just and reasonable. Rules should allow
entry to be free of barriers, they should not guarantee that entrants are compensated at their
expected levels.

PJM acknowledges that competitive entry has been robust. “Since the inception of RPM
in 2007, 50,792 megawatts (‘MW’) of new generation capacity has been added.” Most of this
entry has resulted from investment by by entities other than utilities. “By PJM’s estimation,
conservatively 70% of this new entry came from merchants, with the remainder brought in by
vertically regulated or public power utilities.” PJM stated in its 2016 Resource Investment in
Competitive Markets white paper: “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.” Clearly investors are still investing and entry is open to any and all parties.

B. PJM makes no demonstration of an externality that the proposals address

PJM states that through policies such as RPS, “the state is exporting the impact of its
subsidy onto other states and potentially ‘crowding out’ resources that other states (with
different policy choices) may value.” This might be a negative externality argument, though it

10 Id. at p. 46.
11 Id. at p. 2.
12 Id. at p. 10.
notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx
14 PJM filing, at p. 29.
isn’t described as such and there is no demonstration of inefficiency. When there is an inefficient negative externality, there is a misallocation of resources that represents overall social harm. This overall social harm is distinct from equity or distributional issues, where various market participants may fare better or worse under a policy change. If there is an overall inefficiency then consumers will pay more than a competitive level. No such negative externality effect has been demonstrated here.

There is a positive externality effect of state policies. In a positive externality, third parties outside of the parties to a transaction receive net benefits for which they neither pay nor are paid. In the case of state policies, one state opts to have load in its state pay, through retail rates, for a set of resources. When those resources then supply energy or other services into regional markets, they tend to extend the supply curve and reduce prices. PJM explains this effect numerous times including in the example on pages 29-32. Thus, load in other states actually face lower prices than they otherwise would. If PJM and the Commission are concerned about just and reasonable rates for wholesale customers as the Federal Power Act directs, then if anything these policies are a positive not a negative influence on other states.

C. PJM has made no demonstration of a public good or free-rider problem

Another market failure that can theoretically be present is a public good, also known as a free rider problem. PJM does not mention of public goods or free rider problems in the filing. While there are some references to long term reliability impacts, PJM has made no demonstration that reliability is threatened or is being harmed by state policies. Moreover, there is nothing preventing PJM from procuring the reliability services it needs. If market participants build a portfolio of resources with relatively little capability to provide one service, such as an
operating reserve product, supply and demand for that product will meet at a higher price point, signaling more entry of that capability in the future. That is how markets work, and there is nothing about state policies that interfere with that process.

V. **FERC has traditionally allowed public policies to affect prices, consistent with typical markets**

Prices have been deemed just and reasonable even when public policies affected them. A wide range of state and federal policies have affected quantities and prices in power markets since the inception of US electricity markets. For example, there might not be any nuclear generation in operation were it not for the Price-Anderson Act limiting liability for unit owners. We might not have as much natural gas generation if intangible drilling costs and depletion allowances were not allowed to be deducted under federal tax law. Many states provide incentives for the production of fuels that are used in electricity generation. A large amount of generation participating in markets is part of a state regulatory rate base which affected the development of those sources and influences their ongoing behavior. Health and safety regulations affect firm behavior in electricity markets as with most other industries. Public infrastructure affects delivery costs of most products in most industries. The existence of these policies affects the amount of supply, the cost of that supply, the point at which supply and demand intersect, and the resulting price.

FERC’s regulatory framework has been to set market rules in a manner that accounts for public policies in the same way as other exogenous factors that impact markets. The basic framework of treating public policies like other exogenous factors has generally held true since the establishment of organized wholesale markets. PJM proposals to expand state policy
mitigation in a way that will administratively set prices for gigawatts of supply without any foundation in market power or other market failure, solely because those units are affected by one particular exogenous factor, is a significant change in policy.

Just like any cost of production, a public policy is something that can affect a seller’s willingness to accept or a buyer’s willingness to pay. Quite directly, some generation owners must purchase sulfur dioxide allowances through EPA-regulated markets (which have existed for as long as power markets), and those suppliers may reflect the cost of such allowances in their sales or bid prices. Air emission regulations can affect allowable generation run times. Some policies may tend to raise certain suppliers’ bids and/or prices such as emissions allowances, and others may tend to decrease bids and/or prices, such as renewable energy incentives. For many years, markets have been deemed workably competitive and prices have been deemed just and reasonable by the Commission despite public policies affecting their outcomes.

There are values beyond kilowatt-hours and reliability services that legitimately factor into just and reasonable prices. PJM acknowledges this point: “The theoretical ideal market approach to that issue would be to unbundle the currently unvalued attributes and enable resources to compete to provide those attributes, for example, through a carbon emissions objective embedded in the wholesale market.”\(^\text{15}\) PJM prefers a different way of pricing environmental services but seems to concede the point that the cost of environmental services can be part of just and reasonable prices.

\(^{15}\) PJM filing, at p. 54.
VI. PJM’s preferred “repricing” approach raises prices above just and reasonable levels

Prices would tend to be higher under PJM’s preferred repricing approach. This effect is intentional, to avoid what PJM considers to be price suppression from state policies. Price-setting is performed in the second stage of the auction by substituting “competitive” (i.e., higher) prices for “subsidized” prices. Inserting higher bids will in most cases lead to higher prices.

Wealth will be transferred from customers to existing suppliers under repricing. Whether those suppliers receive as much as they would have expected but for the state policy is immaterial. The price they receive is above the efficient level with all supply and all demand bidding their marginal opportunity costs as would occur in a competitive market.

Even the subsidized units are paid higher prices than they would under the status quo because they will likely clear in the market and will receive a higher price than would occur without the mitigation.

Capacity repricing does not attract new supply. In PJM’s example, one can see that potential new entrant units that do not clear in the first stage but who would willingly enter at the repriced level, are not taken and would not receive the capacity payments. Thus, the higher price leads to no new supply from which customers could benefit. These resources that do not clear in the first stage are the only resources for which the difference between step one and step two prices would have a meaningful effect on market entry and exit decisions. Thus, all capacity repricing does is ensure that resources that would already be incented to enter or
stay in the market with *first step* prices are paid an even higher amount, when that higher amount is not necessary to ensure market entry or continued market participation.

Capacity repricing creates an incentive for inefficient economic withholding. Companies that own portfolios of generation would benefit from the higher re-priced price level. They would have more incentive than under the status quo to use their units on the margin to withhold output or bid higher in order to affect that price. Under PJM’s *current* rules, if that resource makes an offer based on its true costs, it will clear only where doing so allows the resource owner to earn a profit or at least break even. But under the repricing proposal, the offer price of that resource becomes important even where that resource has no chance of earning a profit in the market. There is a chance that the resource will not clear, but will nevertheless be the resource that sets the price for resources that do clear.

VII. **MOPR-Ex raises prices above just and reasonable levels**

PJM’s alternative approach, MOPR-Ex, is similar to re-pricing in terms of raising capacity market prices in response to state policies. By artificially increasing the cost of certain low-cost resources bidding into the market based on arbitrary distinctions about what kind “out of market” payments can legitimately be factored into their offer price, the extended MOPR will cause a higher-cost resources to be marginal, thereby increasing capacity market clearing prices. It also forces customers to pay twice for the capacity they need; once for the state-required payment, and again in the higher resulting capacity price from extending MOPR.

VIII. **The proposals both violate the Commission principle of shifting risk to suppliers**

The Commission’s recent order on ISO-New England’s CASPR proposal stated that one principle for capacity markets is to “shift risk as appropriate from customers to private
capital.”\textsuperscript{16} That has been a core element of electricity restructuring and competition and is important for long-run efficiency. PJM states that the status quo with state policies “shifts risk from private capital to customers, because resource owners are insulated from the financial consequences of a resource that cannot, based on its economics, clear in a competitive auction, with customers (and other wholesale market participants . . .) bearing the costs of keeping the resource in operation.”\textsuperscript{17} However the effect is the opposite of what PJM claims because the two proposed mechanisms shield investors from risks that are properly borne by investors, and returns those risks to customers.

Risks of public policy changes are borne by investors in electricity markets, just like all other markets. Any product subject to health, environmental, safety, or other forms of regulation can have its market opportunities impacted by changes in these regulations. Product prices and stock values are changed every day in other industries. Investors in industries where there is a lot of regulation, such as telecommunications and pharmaceuticals, pay close attention to state as well as federal regulation, as they should in electricity. Risks do not disappear if RTOs mitigate state policies,\textsuperscript{18} they are simply shifted from investors to customers in a zero sum game.

PJM’s position is based on what it thinks investors should know about: “Investors and market participants also are more likely to have better understanding of and familiarity with acts of Congress, compared to individual state action focused on a particular unit or project.” Yet electricity is not the only industry where state policies matter, and it should not be a

\textsuperscript{17} PJM filing, at p. 46.
\textsuperscript{18} PJM filing, at p. 71.
surprise to investors that state policies matter in an industry where jurisdiction over generation is left to states under the Federal Power Act.

IX. The proposals may harm investor confidence more than they help

The Commission recently stated that a goal of capacity markets “is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates.”\(^{19}\) Investor confidence does not come from shielding market participants from all risks. Rather investor confidence comes more from having stability and clarity in laws and policies so they can reasonably predict the types of changes that may occur. The two proposals filed by PJM upend the traditional roles of states in making electricity resource choices that has been firmly established in the regulatory structure from its beginning, which widens rather than narrows the range of outcomes investors must consider.

If public policies were to be mitigated, deterred, or otherwise adjusted by the Commission rather than accounted for in the same manner as other exogenous factors, there would be no clear boundary governing when the Commission might intervene and when it might not. Policies vary in many dimensions: state vs. federal, capital cost vs. operating cost support, forms of insurance vs. direct cost support, environmental vs. economic development vs. other social objectives, forms of zoning and resource access vs. economic factors, and more. Sometimes impacts are direct and sometimes they flow indirectly from upstream sectors. Some policies such as Renewable Portfolio Standards do not pick a single technology or resource but allow a measure of competition. PJM provides no reasoned principle separating state policies

\(^{19}\) CASPR Order at P 21.
warranting mitigation and not. With no boundary between what policies are mitigated and which are not, there is no regulatory certainty.

PJM’s suggested mechanisms create a situation in which determinations need to be made on which policies count as “subsidies” and how to mitigate each one. Such decisions, subjective as they are, could easily be changed over time so there would be little regulatory certainty. Both proposals require determinations about which policies are “actionable.” There could very easily be disagreements about which policies are actionable, as there is no principled distinction or bright line provided to guide investors’ decisions.

Investor confidence would be higher if the traditional boundaries governing RTO intervention in competitive markets in response to exogenous factors were maintained. Commission policy has been clear that prices would be set where supply and demand meet, if market power is absent or has been mitigated. Thus, it would have been reasonable for investors to assume that state policies would not be mitigated unless they crossed the line into buyer-side market power or some other form of market power. An expansion of FERC’s policy of mitigating state policies significantly changes the line between state and federal roles in wholesale markets and moves the line to an ambiguous place given the slippery slope of deciding which interventions count as “out-of-market revenue sources”, likely creating more uncertainty than it resolves.

These proposals add a whole new category of regulatory risk investors need to consider. Investors must consider state and federal environmental, health, and safety regulations and legislation as they affect electric industry participants as a normal course of doing business. These policy-making bodies can be very subjective in what policies they choose to put in place.
If RTOs remained objective engineering bodies as they were originally designed, that would contain regulatory risk to the traditional sources rather than create a whole new source of hard-to-predict subjective policies.

Investor confidence would also suffer from the lengthy process of interpreting new rules once they are implemented. Under either proposal there will be many questions and details to be clarified in tariffs over time.

X. Conclusion: with no economic policy justification for mitigation, and higher prices, the proposal leads to inefficiently high prices

There is no market power or other market failure demonstration that either of PJM’s proposed approaches remedy. The purpose of mitigating market power, internalizing externalities, and preventing free-riding in the case of public goods is to correct a well-defined market failure so that supply and demand can set efficient prices. If there is no demonstrated market failure, then administratively raising prices is moving prices to a less efficient point. Inefficient prices over the long-term harm customers.

No value accrues to customers from the higher prices. Entry is not attracted, environmental performance does not improve, and there are no other market or non-market values that have been shown to benefit customers. They simply pay more, and wealth is transferred to existing suppliers.

The two capacity market proposals decrease efficiency by harming states’ ability to internalize environmental externalities. States have always had environmental responsibilities and can enact policies to internalize externalities. Internalizing externalities increases efficiency. Thus, these proposals to reduce their ability to do so reduce market efficiency.
UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection LLC ) ER18-1314-000

Verification of Robert Gramlich

On Behalf of the Sustainable FERC Project, Natural Resources Defense Council, and Sierra Club

I, Robert Gramlich, declare under penalty of perjury that the attached affidavit is true and correct to the best of my knowledge, information and belief.

__________________
Rob Gramlich

Execution Date: May 7, 2018
Wilson Affidavit
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.                                  Docket No. ER18-1314-000

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE PROTESTS OF
DC-MD-NJ CONSUMER COALITION, JOINT CONSUMER ADVOCATES,
AND CLEAN ENERGY ADVOCATES
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I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have over thirty years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission (“Commission”), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, Russia, and other regions. With regard to the PJM system, I have also been involved in a broad range of other market design and planning issues over the past several years.
4. With regard to the capacity market design issues that are the subject of this proceeding, I have been involved in these issues in PJM, New England, California, the Midwest, and other regions. Since PJM Interconnection, L.L.C. (“PJM”) proposed the Reliability Pricing Model (“RPM”) capacity construct in 2005, I have prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues, including the minimum offer price policies addressed in this docket. I submitted comments in the Commission’s technical conference on state policies and wholesale markets in Docket No. AD17-11.\(^1\) I also actively participated in the Capacity Construct Public Policy Senior Task Force (“CCPPSTF”) stakeholder process that led to this filing.

5. On April 9, 2018, PJM filed proposed changes to its tariff to address the potential impacts on RPM prices of resources receiving state subsidies (“PJM Filing”). This affidavit was prepared at the request of the Maryland Office of People’s Counsel, New Jersey Division of Rate Counsel, and District of Columbia Office of People’s Counsel (“DC-MD-NJ Consumer Coalition”), Illinois Citizens Utility Board, Illinois Attorney General, Delaware Division of the Public Advocate, West Virginia Consumer Advocate Division, Kentucky Attorney General, and Indiana Office of Utility Consumer Counselor (“Joint Consumer Advocates”), and Sierra Club and Natural Resources Defense Council (“Clean Energy Advocates”). My assignment was to evaluate the need for and likely impacts of the proposed changes to RPM.

II. Overview and Recommendations

A. The Issue: Capacity Price Formation in the Presence of Policy Resources

6. When states financially support the development or retention of resources with environmental or other attributes that satisfy public policy objectives not valued in the wholesale markets (hereafter, “public policy resources”), the Commission has found that the resulting “out-of-market” revenues provided to the public policy resources potentially create a conflict between three objectives for forward capacity constructs:

1. that all resources, including public policy resources, should receive capacity supply obligations and payments, recognizing their contributions to resource adequacy, so consumers don’t “pay twice” for duplicative excess capacity;

2. that capacity prices should not be suppressed by the presence of public policy resources, which price suppression could discourage “competitive”, in-market resources, and compensate existing resources unfairly; and

3. that the capacity construct should clear a reasonable total quantity of capacity at a reasonable total cost.

7. The never-ending struggles around changes to minimum offer price (“MOPR”) rules in PJM and elsewhere reflect, to a large extent, that different stakeholders disagree as to the impact of public policy resources on capacity prices, and place different priorities on these conflicting objectives. Not surprisingly, capacity sellers and RTOs tend to emphasize objective #2 while consumer interests place more importance on objectives #1 and #3.

8. The PJM Filing proposes two alternative packages of changes to RPM, both intended to support higher RPM price outcomes in the presence of resources receiving state policy support. PJM’s preferred package is its Capacity Repricing Proposal (hereafter, “PJM’s Repricing Proposal”). The alternate proposal, MOPR-Ex, was primarily developed by the PJM Independent

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Market Monitor, Monitoring Analytics, LLC. PJM claims that either proposal is just and reasonable (p. 42) and that Commission action is needed now (p. 18).

**B. There is No Present Need for Comprehensive Revision or Expansion of the RPM MOPR Rules**

9. Resource adequacy has been easily achieved in the PJM footprint in recent years, with large amounts of excess capacity cleared through RPM despite numerous retirements. There has been substantial entry and exit each year, large amounts of uncleared resources, and more and more offers at prices close to clearing prices (the supply curves are becoming more gently sloped). This means that RPM has substantial ability to absorb new resources of all types, while maintaining clearing prices within a range that balances entry and retirements. The RPM market is not nearly as fragile as suggested by PJM and other proponents of major tariff changes to support higher capacity price levels.

10. PJM’s estimates of the potential impacts of new or retained resources on RPM prices (PJM Filing, pp. 28-29) ignore these dynamics and, as a result, greatly overstate the potential impacts. New entrants generally offer at low prices, whether or not they receive state policy support; and all new entry at low prices has the same potential impact on RPM prices. However, as market participants plan their entry and exit choices, they take into account the anticipated supply/demand balance and the anticipated actions of other market participants that affect that balance. As a result, despite entry and exit each year, the RPM supply curves end up being quite similar year to year.

11. Both of PJM’s proposals (the Repricing Proposal, MOPR-Ex) represent fundamental changes to the RPM MOPR rules, which are designed to support higher capacity prices by imposing minimum offer prices on certain resources. Minimum offer price rules are market interventions that lead to administrative pricing. It should be a goal of the design of such
interventions that they have the minimum necessary impact for the minimum necessary duration, allowing the market to return to market-based pricing. Both proposals ignore the market’s dynamic ability to absorb incremental resources with clearing prices maintaining, or quickly returning to, the levels that balance supply and demand, entry and exit.

C. PJM’s Repricing Proposal is Fatally Flawed and Would Be Harmful to the Market and Costly to Consumers

12. PJM’s Repricing Proposal contains three characteristics that I consider to be fatal flaws – each individually warrants rejection of the proposal. The first fatal flaw has to do specifically with RPM, while the other two are market design fatal flaws of a more generic nature.

1. The first fatal flaw is that PJM’s Repricing Proposal establishes an auction clearing price and quantity pair that does not lie on the auction’s sloped Variable Resource Requirement (“VRR”) capacity demand curve; as discussed in detail below, under very likely circumstances, the auction result would lie well above the VRR curve. This violates a bedrock principle of capacity market design – auction outcomes must lie upon the agreed sloped demand curve. As noted below, the Commission has seen a proposal with this feature before, and rejected it on this basis. A proposal with this characteristic would require, among other things, a fundamental reconsideration of the interpretation and role of the sloped capacity demand curve, and of its shape and position. No such reconsideration has occurred.

2. The second fatal flaw is that PJM’s Repricing Proposal divorces the determination of who clears in the auction from the determination of what price those winners will be paid, which will badly distort resources’ offer prices. Functioning markets and workable market and auction designs share the characteristic that a seller’s offer price will determine whether the seller will make a sale, and also the minimum price the seller might receive. This disciplines offer conduct, pushing sellers to offer based on cost. PJM’s Repricing Proposal will determine who clears the auction based on one supply curve (“Stage 1”), but will determine the price to be paid based on a potentially very different supply curve (“Stage 2”) that, as I will
show, is very likely to result in a much higher clearing price in Stage 2. This will create strong incentives for sellers in a broad cost range near the likely Stage 1 clearing price to “race to the bottom” – offer below their cost to try to clear in Stage 1, knowing that they will get paid the much higher price established in Stage 2. And higher-cost sellers that won’t enter the “race to the bottom” will realize that their offer prices are not meaningless; they can contribute to higher Stage 2 clearing prices (that will be earned by all affiliated cleared resources) by “clearing out the top” and offering at the highest prices allowed. I am not aware of any market or auction that has this characteristic except perhaps under trivial circumstances (and as shown below, the impact in this instance is far from trivial). This design characteristic – one process determines who clears, a quite different one the price – is unworkable and should be considered an auction design non-starter.

3. The third fatal flaw is related to the second one. As noted, under quite reasonable assumptions, the Stage 2 clearing price can be well above the Stage 1 price that resources must offer under to be chosen in the auction. That means that the Stage 2 clearing price would likely be set by the offer from a resource that knew it would not be receiving a capacity commitment. In addition, as noted above, such resources have incentives to offer above cost, to support a higher Stage 2 clearing price. Thus, the Stage 2 clearing price is arguably quite arbitrary and not cost-based or the result of a workably competitive market mechanism. While it futile to attempt to administratively reconstruct the “competitive” price that would occur without subsidies – the market would adapt to that alternate world, adjusting entry and exit decisions – the Stage 2 price is a particularly flawed attempt to determine such a price. This design characteristic – a price that will determine billions in capacity payments may be set by an offer from a resource that had nothing at stake in selecting its offer price, and indeed had incentives to inflate its offer price – should also be considered an auction design non-starter.

13. I simulated the results of PJM’s Repricing Proposal for the RTO Region using actual demand curves and supply curves based on recent auctions. Even assuming market participants naively do not adjust their offers based on the incentives created by PJM’s Repricing
Proposal, if 5,000 MW (the minimum amount) is repriced, it would raise RPM prices and the cost to consumers by 28%; if 9,000 MW is repriced, it would raise prices and cost by 50%. Under the assumption that half of the market participants would adjust their offers due to the clear incentives created by the PJM Repricing Proposal, prices and cost would increase by 66% if 9,000 MW is repriced, or by 42% if only 5,000 MW is repriced. These examples are explained in detail and summarized in Figures 1 to 5 and Table 1 below.

14. The incentives created by the PJM Repricing Proposal would raise RPM prices and costs; as explained below, the incentives would also cause the RPM supply curves to become steeper in the relevant range near likely clearing prices. This is a highly undesirable result. Over recent years, RPM supply curves have become more gently sloped, which contributes to more competitive conduct and relatively stable prices over time. These conditions provide stronger incentives for investment in the PJM markets. The PJM Repricing Proposal would lead to steeper supply curves and more volatile prices, weakening investment incentives and increasing risk premiums.

15. PJM suggests that market participants may not act on the incentives resulting from its Repricing Proposal, because the RPM Stage 1 and Stage 2 prices and price differences might not be sufficiently predictable, so such action would be “speculative.” This would seem to leave PJM, market participants and the Commission hoping for market uncertainty and volatility, because the market design would only work acceptably under such conditions.

D. The Proposed Applicability and Duration of Mitigation Are Excessive Under Both Proposals (Repricing and MOPR-Ex)

16. In addition to the issues raised above, both of PJM’s proposals also share the following characteristic: Both call for mitigating (repricing) resources with actionable subsidies for an unlimited period, without regard to how many years the market may have had to adjust to
and absorb the resource, either before it enters the market, or after. In applying market interventions that result in administrative prices (such as MOPRs and repricing do), the goal should be to apply the minimum intervention for the minimum period, such that the market can absorb and adjust to the resource, and return to market-based pricing without interventions as soon as possible. MOPRing or repricing a resource year after year, despite plenty of time for the market to absorb the resource, leads to artificial prices that do not reflect the true supply/demand balance, and that delay the market’s adjustment to the resource. Any tariff rules to expand the mitigation or repricing of resources with actionable subsidies should limit the mitigation or repricing in the following two ways:

1. Resources with actionable subsidies that meet criteria indicating that the market has been able to absorb them should not be mitigated or repriced. The criteria would have to do with a) how far in advance the resource’s entry was known, and perhaps b) the size of the resource compared to its zone of entry.

2. When mitigation or repricing does apply to a resource, the duration of the mitigation or repricing should be limited, and should again depend upon the advance knowledge and the size of the resource compared to the zone of entry.

17. These changes would be more consistent with the recently-approved provisions of ISO New England’s capacity construct to address policy resources, under which such resources are treated as existing resources and no longer mitigated once they clear in the new substitution auctions.³

18. The remainder of this affidavit is organized as follows. The next section discusses PJM capacity market conditions and the ability of the market to absorb new entry and retirements without impacts on prices. It suggests that there is not a crisis calling for urgent action on the

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³ 162 FERC ¶ 61,205 Order on Tariff Filing, issued March 9, 2018 in Docket No ER18-619.
issues raised in PJM’s Filing. The final section evaluates PJM’s Repricing Proposal, and describes in greater detail the three fatal flaws noted above, with numerical examples.

III. PJM’s Capacity Market and Policy Resources

A. Resource Adequacy is in Good Shape in PJM; There is No Imminent Crisis

19. As PJM acknowledges, year after year, RPM clears substantial amounts of excess capacity, at prices well below the administrative Net CONE values. Resource adequacy in PJM is in good shape. This is largely due to flat loads, moderate natural gas prices, and declining costs for natural gas and renewable resources, as PJM also acknowledges (p. 11). These circumstances are not expected to end anytime soon. New resources are likely to continue to push into the PJM market through RPM, even if, as has been the case in recent years, many higher-cost existing resources are unwilling to retire.

B. The PJM Capacity Market has become Increasingly Dynamic and Competitive with Substantial Ability to Absorb New Resources of All Types

20. As the PJM Filing states (p. 37), “A properly designed competitive market will address excess or shortage positions over time through the actions of competitive market participants.” Over the past several years, RPM base residual auctions have seen a substantial volume of entry and exit in each auction. Specifically, over the past six delivery years, the base residual auction has seen over 35,000 MW of incremental generation resources, while each auction
has also had 11,000 to 18,000 MW of uncleared resources;\(^4\) and over six years from June 1, 2011 through June 1, 2017, just under 25,000 MW of installed capacity deactivated in PJM.\(^5\)

21. Market participants generally will select the timing of retirements and new capacity additions in anticipation of the RPM supply-/demand balance and price level; if RPM prices are expected to rise, some retirements may be delayed or relatively more new entry may be offered, and if prices are expected to be soft there might be more retirements or some new entry may be delayed. Such adjustments have kept RPM prices within a limited range over the past several years despite the retirements and new entry. In addition, various short lead time resources that can efficiently take on RPM obligations, or not, on a year-by-year basis depending upon need and prices (such as some imports, some demand response, and resources that are economic on an energy-only basis) also tend to buffer the RPM price changes from year to year.

22. When certain additional resources are expected to enter or exit the market (be it “competitive” or sponsored resources), market participants will take these changes into account in planning the timing of retirements, other new entry, and other actions that affect the balance of supply and demand. If the additional resources or retirements are anticipated well in advance, it is reasonable to expect that they are fully anticipated and absorbed by market participants’ adjustments, and have minimal, if any, impact on capacity prices.

23. In particular, with regard to resources with state policy support of some kind, states generally pursue lengthy regulatory processes before any procurement of new resources to meet state mandates. In most cases, state policies result in quantities of new capacity that are relatively

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\(^4\) PJM, 2020/2021 RPM Base Residual Auction Results, Tables 6 and 8.

small and known well in advance of the RPM auctions in which they first participate. To the extent the market has had ample time to see that these resources were coming, it is reasonable to assume that the incremental resources are reflected in market participants’ various entry and exit decisions, and do not affect price appreciably.

24. While the entry of the public policy resources will likely correspond to some delay of other new entry, acceleration of retirements, or adjustments by resources able to enter and exit on a year-by-year basis, this displacement is a natural consequence of the policy, perhaps even an objective of the policy.

25. When, on the other hand, an incremental (or retained) resource was not fully anticipated by the market (due to, for example, a relatively last-minute state action affecting a large resource), it could have some impact on the RPM auction. However, even in this case, after a few delivery years it should again be the case that the market has adjusted to and absorbed the additional capacity, with RPM prices again finding the point that balances supply and demand, entry and exit. So while the resource may have had an impact initially, it is reasonable to assume that after it has participated in a few auctions there is no further lasting impact on RPM prices.

C. PJM’s Estimates of the Impacts of State-Supported Resources on RPM Prices Are Vastly Overstated

26. The PJM Filing at pp. 28-29, citing to the affidavit of Mr. Adam J. Keech, Executive Director, PJM Market Operations (Attachment E), alleges that state subsidies can result in large impacts on RPM clearing prices. For example, citing to auction sensitivity analyses, Mr. Keech suggests (p. 2) that adding 6,000 MW in the Rest of RTO region (outside of the Mid-Atlantic) would reduce RPM prices by 21%. These estimates are based on oversimplified calculations that
vastly overstate the potential impacts of incremental resources. PJM’s Independent Market Monitor has made similar claims, using the same flawed approach.

27. As a preliminary observation, note that new resources, whether subsidized or “competitive”, generally offer at low prices that are very likely to clear in the RPM auctions; and all new entry that offers at low prices and clears, whether subsidized or “competitive”, has exactly the same impact, if any, on RPM clearing prices. So the 50,792 MW of new generation capacity that has been added from 2010 to 2017 (PJM Filing, p. 9) would all have had the same impact on RPM prices, if any, as any future new entry, whether subsidized or “competitive”.

28. If incremental resources have huge impacts on RPM prices (as PJM and Mr. Keech allege), how can RPM prices have remained well above zero? The answer was explained in the previous section: as entry and exit occur, other resources are adjusting entry and exit plans, resulting in a buffering of RPM clearing prices. The RPM supply curves are less steeply sloped than in the past, which moderates the price impact of changes in supply or demand. More important, market participants respond to other participants’ entry and exit decisions by adjusting their own entry and exit plans. As a result, the RPM supply curves generally end up in about the same place year to year, and result in roughly similar prices, despite various new resources and removed resources.

29. By contrast, Mr. Keech’s calculations simply add or remove resources, assuming all other resources’ offer prices and quantities are unchanged, and ignoring how the market might adjust to the change in resources, if known in advance, with adjustments to new entry or retirements (among other adjustments, as described in the previous section). Mr. Keech’s simple calculations would be accurate for a change in a resource that catches the market totally by surprise – for example, a last-minute action allowing a resource to participate in the auction that the market
expected would not participate. Such a “shock” could potentially have the impacts suggested by Mr. Keech’s calculations, for a single auction. However, by the next RPM auction, the market would have reacted to and absorbed the resource, with its presence reflected in market participants’ forecasts of prices and needs, and undoubtedly reflected in some participants’ choices to adjust their actions or timing.

30. The fact that there has been so much entry (and exit) through RPM over the past several years, while RPM prices have remained in roughly the $70 to $170/MW-day range, reflects this dynamic – market participants are adjusting their entry and exit timing based on anticipated market supply/demand balance and resulting prices. In particular, gas-fired combined cycle units are apparently economic at recent RPM price levels, and will enter at such levels and keep prices from rising higher. There are many more new plants (mainly combined cycle) eligible for participation in RPM than participate and clear in each auction, suggesting that some plants may be holding off and waiting for additional retirements and/or somewhat higher prices.

31. Mr. Keech also discusses the economic principles behind resources’ offer price choices, and what constitutes a competitive offer (Attachment E, p. 4). His discussion is rather vague; he refers to a resource’s “cost” or “revenue need” without indicating exactly which of the many cost concepts used by economists, and over what time frame, he has in mind. However, he apparently discusses going-forward costs, and makes no reference to opportunity costs. As such, his view contradicts PJM’s position in the Capacity Performance docket, accepted by the

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6 For instance, in the 2020/2021 RPM base residual auction, while 12,161.0 MW of new resources received Competitive Entry exemptions from the MOPR, only 2,675.6 of these MW cleared the auction. 2020/2021 RPM Base Residual Auction Results report, p. 5.
Commission, that under Capacity Performance, any RPM offer up to Net CONE times the Balancing Ratio is competitive, due to the opportunity cost of taking on a commitment.7

32. The PJM Filing also includes an over-simplified and flawed example, not supported by an affidavit, upon which it alleges that a state subsidy program “is being underwritten by other participants in the wholesale market.” First, note again that any entry, including purely merchant entry, would potentially lower market prices in the same manner, and, therefore, would also be “underwritten” by other market participants, under PJM’s flawed logic in this example. Furthermore, the example includes a new entrant that needs $45/MW-day to enter, and incorrectly suggests that subsidized entry would harm the entrant. If there is no subsidized resource, the market clears at the entrant’s $45/MW-day offer, but with the subsidized resource the entrant does not clear. The entrant, according to the example, is indifferent between these two outcomes (neither makes any net revenue over cost), but the PJM Filing incorrectly suggests the subsidized entry results in harm to the entrant, stating (p. 32) that the new entrant “forgoes the $45/MW-day it would have received.”

33. To summarize, because the market is dynamic and market participants are adjusting their entry, exit, and other plans taking into account the anticipated supply/demand balance and prices, it is unclear what impact, if any, a new resource has on RPM prices, especially if its entry has been anticipated well in advance. PJM’s impact estimates would, at best, be applicable only to resources that catch the market by total surprise.

7 155 FERC ¶ 61,157, Order on Rehearing and Compliance, P 184 (noting that the Commission accepted PJM’s Capacity Performance default offer cap (Net CONE times the Balancing Ratio) on the grounds that it is based on a reasonable estimate of a low-end competitive offer, after accounting for all marginal costs, opportunity costs, and risks associated with assuming a Capacity Performance commitment).
D. Many of the Potentially Subsidized Resources Would Receive Payments to Reflect Value Not Captured in the PJM Markets

34. PJM suggests there is an imminent crisis calling for immediate Commission action, referring (at p. 24) to “a growing trend among the PJM states... to intervene in resource selection with targeted subsidies.” Notably, the state programs PJM identifies all exclusively pertain to zero-carbon resources (p. 25, noting zero-emission credit programs, off-shore wind procurement, and renewable portfolio standards). Anticipated subsidies generally pursue legitimate policy goals of geographically broad value, such as carbon reduction and encouraging innovation, that are not valued in the PJM markets. While the preferred approach, in the face of such environmental and learning externalities, is generally to bring those values into the markets, in the meanwhile, subsidies to address such externalities arguably represent a second-best approach that enhances market efficiency.

35. Furthermore, these policies, which generally either support entry over time by new zero carbon resources, or further retention of zero carbon resources that have been in the market for decades, typically result from lengthy, transparent regulatory processes. The new zero carbon resources will typically be added to the market at a steady pace that is known to the market well in advance, and can easily be absorbed (especially since these resources are typically assigned capacity values well below their installed capacity ratings). The existing zero carbon resources that may be retained by such programs are already in the market so generally do not need to be absorbed.
IV. Evaluation of PJM’s Repricing Proposal

A. PJM’s Repricing Proposal: Description

36. The basic idea of PJM’s Repricing Proposal (described in the PJM Filing, pp. 59-96), is as follows. When repricing is triggered (when the quantity of cleared resources with Actionable Subsidies exceeds 5,000 MW across the RTO, or 3.5% of the reliability requirement in any modeled zone; PJM Filing, p. 52), the RPM Base Residual Auction software would be run to solve the auction twice, in two “stages.” In what PJM calls Stage 1, no resources are repriced; so capacity resources with Actionable Subsidies (hereafter, “CRAS” resources) would presumably be offered at low prices and “clear” the Stage 1 auction. Stage 1 would determine which resources will receive capacity supply obligations (“CSOs”); all resources that clear in Stage 1 would receive CSOs for their cleared quantities.

37. Then Stage 2 of the auction would be run, for the sole purpose of determining the price to be paid to the resources that cleared in Stage 1. In Stage 2, PJM would reprice the CRAS resources (substitute “Actionable Subsidy Reference Prices” for the CRAS resources’ voluntary offer prices), while all other resources’ offers are unchanged, with the goal of removing the impact of subsidies on the resulting Stage 2 clearing price. The repricing would generally associate very high offer prices to all or nearly all CRAS resources, pushing them out of the relevant portion of the supply curve. As a result, the supply curve would shift to the left for Stage 2, which would in general result in a higher clearing price. Then all resources that cleared in Stage 1, including any CRAS resources that cleared in Stage 1, would get CSOs and be paid the Stage 2 clearing price. The clearing price from Stage 1, and the cleared quantity from Stage 2, are not used.

38. Note that under PJM’s Repricing Proposal there likely would be resources that offered at prices below the Stage 2 clearing price, but above the Stage 1 clearing price. Since these resources (sometimes referred to as “in-between” or “tweener” resources) were offered at prices
below the Stage 2 clearing price (which is intended to be a “competitive” price), they are presumably economic; but under PJM’s proposal, having failed to clear in Stage 1, they do not receive CSOs.

39. With regard to the three conflicting objectives in MOPR design identified above, PJM’s Repricing Proposal at least nominally addresses the first two objectives, while sacrificing the third objective:

1. All CRAS resources that clear get CSOs (as a result of Stage 1); and
2. The clearing price is set to a purportedly “competitive” level due to the repricing of CRAS resources (Stage 2); however
3. The reasonable total cost objective is compromised (discussed further below).

40. There are of course various other details to PJM’s Repricing Proposal; these are not discussed here as they are not important to my evaluation of the proposal.

B. History of Proposals for Two-Stage Capacity Market Repricing

41. The New England ISO raised the possibility of such a two-stage capacity pricing approach (also sometimes called “two-tiered”) in 2010, in a proceeding pertaining to its minimum offer price rules. The Commission rejected the proposal, finding that it would have cleared a quantity of capacity in excess of the Net Installed Capacity Requirement, thereby violating what it referred to as a “bedrock principle” of the New England capacity market (which at the time was designed to clear exactly the Net Installed Capacity Requirement).\(^8\)

42. Two-stage approaches were again proposed in New England in 2016, in the context of the New England “IMAPP” (Integrating Markets and Public Policy) stakeholder process. The proposals did not receive sufficient support, and stakeholders ultimately settled on an entirely different approach.

43. PJM first proposed its two-stage capacity market concept in a white paper in June, 2016. PJM’s proposal was discussed at a Grid 20/20 event in August, 2016, and it remained one of the many proposals considered throughout the CCPPSTF stakeholder process in 2017. Two other two-stage proposals were also considered by CCPPSTF. In the final CCPPSTF poll, PJM’s proposal gained only 26% support, while the other two-stage proposals gained less than 20% support.

44. I am not aware of any market in which such a two-stage capacity pricing proposal has been implemented.

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C. PJM’s Repricing Proposal: Evaluation

45. This section of my affidavit evaluates the market design elements of PJM’s Repricing Proposal and their potential impacts on RPM, describing in further detail the three fatal flaws in the proposal. To help this discussion, I have prepared examples that illustrate the potential impacts of PJM’s Repricing Proposal under realistic assumptions, focusing on the RTO Region. For these examples I used the VRR capacity demand curve and Net CONE value for the 2021-22 base residual auction.\(^\text{12}\) I used an RTO region supply curve with shape and slope similar to the supply curves from recent base residual auctions, as reported by The Brattle Group in its

Quadrennial Review report. The supply curve (depicted in Figure 1, based on a graphic from the Quadrennial Review report) is relatively gently sloped (compared to earlier delivery years), with a slope of $1.25/MW-day/1000 MW up to a price of $100/MW-day, and a slope of $7/MW-day/1000 MW at prices above $100/MW-day up to $200/MW-day (while a case could be made for various other supply curve shapes, the nature of the results discussed below is not sensitive to this detail). I shifted the supply curve to give a clearing price near $100/MW-day, which I consider

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13 The Brattle Group, Fourth Review of PJM’s Variable Resource Requirement Curve, prepared for PJM, April 19, 2018, Figure 13, p. 42.
to be a reasonable starting point. Although higher than the clearing price from the most recent
auction result available at the time of this testimony ($76.53/MW-day, for the 2020/2021 delivery
year), both the average, and median, RTO clearing prices over the past five delivery years are
roughly $100/MW-day.14

46. Figure 2 shows the “base case” auction result with these assumptions, assuming no
mitigation or repricing of resource offer prices. The clearing price is $102.80/MW-day, with a
cleared quantity of 161,474 MW, resulting in a total market annual capacity cost of $6.1 billion.15
The base case represents the result of “Stage 1” under PJM’s Repricing Proposal, in which the
CRAS resources are not mitigated; it also represents the status quo, assuming all CRAS resources
would either not be subject to mitigation, or would qualify for an exemption.

47. I then assumed a quantity of CRAS resources (with actionable subsidies) of 9,000
MW. This assumption is supported by the PJM Filing, Attachment F, Affidavit of Dr. Anthony
Giacomoni (suggesting 4,969 MW of “around-the-clock” capacity to meet renewable targets, and
potentially similar amounts of zero emissions credits; pp. 6-10). This assumption represents about
five percent of the total offered unforced generation capacity in RPM, which is usually about
180,000 MW.16 I assumed these CRAS resources are re-priced in a manner that effectively
removes them from the relevant portion of the supply curve; that is, to prices well above clearing
prices under any of my examples.

15 For brevity and simplicity in these examples, the reported cost will simply be the clearing price times the cleared quantity times 365 days; this calculation ignores, among other complexities, that some of the obligation clears in zones at higher prices, and some is self-supplied or hedged.
16 2020/2021 RPM Base Residual Auction Results, Table 5 p. 17.
1. **Fatal Flaw #1:** Under PJM’s Repricing Proposal, the base residual auction price and quantity result are not consistent with the auction capacity demand (VRR) curve and would result in excessive cost to consumers.

48. Figure 3 illustrates the result of “Stage 2” under PJM’s proposal, with 9,000 MW repriced (and no change in conduct).\(^\text{17}\) Under these assumptions, the Stage 2 result is a clearing price of $154.53/MW-day, an increase of 50 percent compared to the base case. This results in a total annual market capacity cost of $9.1 billion, also a 50% increase compared to the base case.

\(^\text{17}\) Rather than suggesting where in the upper reaches of the supply curve the re-priced 9,000 MW might end up, Figure 3 (and later figures) simply shifts the entire supply curve by 9,000 MW.
This example shows that the PJM proposal can substantially increase the cost to consumers, under what I consider to be reasonably likely assumptions about the supply and demand curves, and CRAS resources.

49. The Stage 2 price corresponds to a quantity of 159,800 MW on the VRR curve; however, under PJM’s proposal, this price will be paid to all resources that cleared in Stage 1 (161,474 MW). Figure 3 also shows the cleared price (from Stage 2) and the cleared quantity (from Stage 1) under PJM’s proposal. This price, quantity pair lies above, not on, the VRR curve.

50. In the 2010 New England case mentioned above, the Commission rejected ISO New England’s two-stage proposal because it would clear a total quantity in excess of the Net Installed Capacity Requirement, and thereby violate a “bedrock principle” of the capacity
construct. In a capacity construct with a sloped demand curve (such as RPM, or ISO New England’s current construct), the analogous bedrock principle is that the auction result lie on the sloped demand curve; the sloped demand curve identifies the universe of acceptable auction clearing outcomes. PJM’s proposal, by resulting in a cleared quantity and clearing price that are not on the VRR curve, violates the bedrock principle, as applied to a sloped demand curve.

51. In rejecting ISO New England’s two-stage proposal for violation of a bedrock principle, the Commission did not have to evaluate the evidence and testimony regarding other fatal flaws of the proposed two-stage pricing approach. While Fatal Flaw #1 is sufficient to reject PJM’s Repricing Proposal, the next fatal flaw is an even more serious problem.

2. **Fatal Flaw #2: Under PJM’s Repricing Proposal, incentives to submit competitive offers are distorted and will lead to undesirable conduct that affects quantity and price, and further raises the cost to consumers**

52. The second issue is that the proposal reflects a fundamentally flawed market approach that would badly distort resources’ choices with regard to offer prices, leading to unintended and undesirable results and further raising cost.

53. Under the current auction rules (or the rules of just about any well-structured auction or market process), a resource’s offer price determines both whether the resource will be chosen in the auction, and also the minimum price the resource will be paid. This generally leads a resource to offer at the price the resource requires in order to want to clear in the auction. That is, the resource’s offer price should be the price needed to make taking on a CSO worthwhile. If the auction clears at a price above a resource’s offer price, it clears and gets a CSO, and is satisfied with this result because the price is enough (likely more than enough) to make taking on the CSO worthwhile. If, instead, the auction clears at a price below the resource’s offer price, the resource does not receive a CSO and is again satisfied with this result, because at that clearing price it does
not want a CSO. An owner might determine the price its resource “needs” to make a CSO worthwhile based on its avoided cost, or an opportunity cost concept, or some other analysis, it does not matter; if the auction is well-structured, the incentive is to make an offer based on the price considered needed (setting aside market power considerations). For the discussion here, this price will be referred to as the resource’s “cost-based” offer price, recognizing that this may be an opportunity cost or have some other basis.

54. However, under the PJM Repricing Proposal, a resource’s offer price does not serve in this role. Under this proposal, the resource will get a CSO and be paid the higher Stage 2 price if and only if its offer is below the lower, Stage 1 clearing price. In the example above, if the resource offers at less than or equal to $102.80/MW-day (the Stage 1 price; Figure 2), it clears, and will be paid $154.53/MW-day (the Stage 2 price; Figure 3).

55. Now suppose the resource’s cost-based offer price would be, say, $115/MW-day. If the resource offers at this price, it will not clear in Stage 1, and will not receive a CSO or payment. But the Stage 2 price (that it won’t get, because it didn’t clear in Stage 1) is well above the $115/MW-day price it needs. So if the owner suspects that Stage 1 may clear in the $90 to 110/MW-day range, and that Stage 2 will very likely clear above $115/MW-day (as in the example), the owner might quite rationally choose to offer somewhat lower than its $115/MW-day price, even though that is below the price it needs. With this strategy the owner would increase the chance that the resource will clear in Stage 1 and get paid the higher Stage 2 clearing price, without much risk of clearing and receiving a price less than its $115/MW-day cost. This strategy is of course more profitable than the initial approach of offering at $115/MW-day (the cost-based offer) and failing to clear.
56. So to the extent 1) it is likely that there will be a substantial wedge between the Stage 2 and Stage 1 prices (which, as shown below, will be the case when there are enough CRAS resources to trigger mitigation), and 2) the likely range of the auction Stage 1 clearing price is reasonably predictable, resources whose cost-based offers are close to or somewhat above the expected Stage 1 clearing price have incentives to lower their offer prices, to increase their chances of clearing in Stage 1 and earning the Stage 2 price. This incentive issue has frequently been noted and is called the “race to the bottom.” To the extent this conduct occurs, Stage 1 will clear a somewhat larger quantity, at a lower Stage 1 price, than if all resources submitted their undistorted cost-based offers.

57. The “race to the bottom” – resources lowering their offer prices below cost, in order to clear the auction Stage 1 to earn the higher Stage 2 price – is one bad incentive created by PJM’s proposal. There is a second one, applicable to higher-cost resources. Now consider a resource whose cost-based offer price is $140/MW-day. Suppose the owner considers it too risky to lower the offer price enough to be likely to clear in Stage 1 (that is, down to the $100/MW-day range, in my example). The owner chooses to not join the “race to the bottom” that he would likely not win (and could potentially regret, if he does clear, but Stage 2 clears below his cost, $140/MW-day). So does the owner offer the resource at $140/MW-day? If the owner accepts that the resource won’t clear in Stage 1 and won’t receive a CSO, it would appear that the selected offer price won’t make any difference.

58. However, while the selected offer price for this resource won’t determine whether the resource will clear (it won’t), the offer price could very well affect the Stage 2 clearing price. Suppose the owner anticipates that Stage 2 will likely clear at a price in the $140 to $170/MW-day range, above his offer price, if the offer is based on his cost. If he instead offers at, say, $190/MW-
day, this removes the resource from the Stage 2 clearing result, and leads to Stage 2 likely clearing at a somewhat higher price than it would have. If the owner has only the one resource, this still makes no difference to the owner. But if the owner has other capacity that will clear Stage 1 in the auction and earn the Stage 2 price, then the owner will likely increase profits by offering this resource not at its cost-based $140/MW-day price, but at a higher price (consistent with applicable market power mitigation rules), in order to support a higher Stage 2 clearing price that will be earned by the rest of the owner’s portfolio. This second incentive problem, applicable to higher-cost resources, has been called “clear out the top”. While resources with costs reasonably close to the anticipated range of Stage 1 clearing prices will be tempted to join the “race to the bottom”, higher cost resources that do not enter the race, especially if affiliated with other resources that will clear, will be tempted to “clear out the top” and help Stage 2 clear at a higher price.

59. Note also that while the owners of CRAS resources can apply for lower, resource-specific repricing based on a resource’s avoidable cost (PJM Filing, pp. 82-85), in many cases owners would have no incentive to do so; this is another perverse incentive resulting from PJM’s Repricing Proposal. While a CRAS resource’s actual cost might be considerably lower than the applicable Reference Price, if the resource is unlikely to clear in Stage 1, the owner would generally prefer a higher rather than lower price imposed on the resource, to support a higher Stage 2 clearing price earned by the owner’s other resources that will clear in the auction.

60. I simulated the potential impact of these incentives issues, on the base of the numerical example discussed above. For the “race to the bottom”, I assumed half of the resources with costs in the $80 to $130/MW-day range would lower their offer prices by 20%, to increase their chances of clearing in Stage 1, while half the resources would not change their offer prices. This assumption leads to the Stage 1 clearing result shown in Figure 4. The Stage 1 cleared
quantity increases by 167 MW, and the Stage 1 clearing price declines by $5.17/MW-day, compared to the results assuming no change in offer conduct. If sellers were more aggressive (if more were lowering their prices, or by larger amounts), the impact on the Stage 1 price and quantity could be larger.

61. I simulated the potential conduct of higher-cost resources by assuming that half of the resources with costs in the $130 to $170/MW-day range would raise their offer prices by $50/MW-day. The Stage 2 clearing results are shown in Figure 5. The Stage 2 clearing price now
increases to $170.70/MW-day, a further 10% increase due to the conduct. The market cost under this scenario is now $10.1 billion, an 11% increase over the repricing result with no change in offer behavior, and 66% higher than the cost under the status quo. The resulting RPM auction price and quantity represent a point even further above the sloped VRR curve, due to the conduct.

62. Table 1 summarizes the results of these analyses. In addition to the 9,000 MW repricing assumption shown in the figures and discussed above, Table 1 also shows results for 5,000 MW of repricing (for this scenario, it was assumed half the resources with cost below

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18 Note that this clearing price is still well below the applicable Net CONE value, $321.57/MW-day. If Net CONE is substantially reduced in future auctions this would scale the VRR curve, and these examples, downward but not change the fundamental conclusions.
$110/MW-day would “race to the bottom”, while half the resources with cost above this level would “clear out the top”). Even this minimum amount of repriced resource leads to substantial differences in price and cost, and large enough price differences to influence bidding behavior.

<table>
<thead>
<tr>
<th>Table 1: Summary of Cases</th>
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<tr>
<td><strong>RTO Region, 9,000 MW Repriced:</strong></td>
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<tr>
<td>Base Case (current rules; = Stage 1)</td>
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<tr>
<td>Repricing, No Conduct Change, Stage 2</td>
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<tr>
<td>Repricing, Conduct Change, Stage 1 Clearing</td>
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<tr>
<td>Repricing, conduct Change, Stage 2 Clearing</td>
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| **RTO Region, 5,000 MW Repriced:** | **Quantity (MW)** | **Price ($/MW-day)** | **Cost ($ bil./year)** |
| Base Case (current rules; = Stage 1) | 161,474 | $102.80 | $6.06 |
| Repricing, No Conduct Change, Stage 2 | 160,545 | $131.50 | $7.75 |
| Repricing, Conduct Change, Stage 1 Clearing | 161,585 | $99.38 | n.a. |
| Repricing, conduct Change, Stage 2 Clearing | 160,092 | $145.50 | $8.58 |

Note: The results shown in italics (Stage 1 prices and costs, and Stage 2 quantities) are not used if repricing is triggered. The Stage 2 cost is calculated using the Stage 1 quantity.

63. The PJM Filing notes these incentive issues, but it notes them and dismisses them in a single paragraph, with only the following discussion (p. 58, citations omitted), and there is no discussion of the incentive issues in either attached affidavit:

“Some stakeholders have raised a concern that this effect of repricing could distort participants’ bidding behavior; for example, encouraging sellers to bid low so as to guarantee they clear in the face of a subsidized low-price offer. To the extent this posits that unsubsidized sellers would offer below their own net costs, so as to commit to provide PJM capacity for a full Delivery Year at a loss, such concerns are speculative, to say the least. It is worth noting, moreover, that in the current PJM capacity market, the high-cost, marginal sellers likely will be less efficient legacy units (with a limited future economic life), as opposed to the new entry units classically assumed to be at the margin.”
64. PJM has been aware of the incentive issues raised by its Repricing Proposal since it was first proposed, in mid-2016. For example, the PJM re-pricing proposal was presented and discussed at the August 18, 2016 PJM-sponsored event, *Grid 20/20: Focus on Public Policy and Market Efficiency*. At that event, Stu Bresler, PJM’s Senior Vice President – Operations and Markets, noted that stakeholders had raised the two incentive issues, and acknowledged the possibility that they could represent fatal flaws.19 Throughout the twenty-two meetings of the CCPPSTF, the incentives issues were repeatedly raised by various stakeholders, including stakeholders representing public power, capacity seller, and consumer interests (perhaps among other interests).20 However, PJM never responded to these concerns with any discussion or analysis; PJM’s only response has been to dismiss the concern as speculative, as it has in the PJM Filing. In a question-and-answer document responding to questions about its proposal, PJM summarily dismissed the incentive issue as follows:21

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“7. How do you think your proposal will impact bidding behavior? Response: Minimum impact as the MW commitment is based on “as offered” with no adjustments.”
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65. While the fact that the commitments are based on “as offered with no adjustments” prevents some types of distortion of bidding behavior, it does not prevent behavior following the clear incentives created by PJM’s Repricing Proposal, as discussed in detail above.

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66. Although PJM has failed to provide any cogent response to concerns about bidding behavior, it could be argued that the incentive problems could be unimportant because RPM prices are somewhat unpredictable. While RPM prices have been somewhat variable (although less so recently), the market design should be robust and workable from a long-run, equilibrium point of view. If the RPM rules are reasonably stable over time, clearing prices should become more predictable. I believe RPM prices have been sufficiently stable recently such that many market participants would find it profitable to act according to the incentives created by PJM’s Repricing Proposal, as suggested in the examples above. In any case, market participants and stakeholders should not be left hoping for uncertainty and volatility, because PJM has implemented a market design that only performs acceptably under such conditions.

67. It could also be argued that this incentive problem would be unimportant if the Stage 1 and Stage 2 prices are not very different, as would be the case if repricing does not shift the supply curve very much. However, as Table 1 above shows, if the minimum 5,000 MW is repriced such that it fails to clear in Stage 2, this can still drive a substantial wedge between the Stage 1 and Stage 2 prices, if the supply curve is shaped as in recent auctions. Again, the market design should be robust under a range of reasonably likely circumstances, including circumstances under which the quantities of CRAS resources may be large.

68. PJM dismisses the incentive issues as “speculative”; I do not consider the conduct assumptions adopted in my examples at all speculative. Perhaps more difficult to explain would be: faced with such an auction mechanism, why would profit-maximizing sellers not behave in this manner? If it is likely that repricing will be triggered (and this will generally be known before the auction), it is easy to roughly estimate the wedge the CRAS resources will create between the Stage 2 and Stage 1 prices. Much of the PJM capacity is owned in large portfolios, and these
owners would rationally segment their resources into those they desire to clear (“race to the bottom”) and those they do not expect to clear (“clear out the top”).

69. PJM apparently does not propose to publish the Stage 1 clearing prices. That would mean that the determination of which resources clear the auction and are selected to provide capacity would be based on a non-transparent, unpublished clearing price. And while not publishing the Stage 1 price could contribute to keeping some market participants guessing about the price level they must beat to clear Stage 1 (deterring adjusting offer prices), market participants with portfolios could easily discover this price, by, say, ensuring that at least a small bit of the portfolio is offered within every $5/MW-day price interval through the range of likely clearing prices.

70. Furthermore, while perhaps many market participants would not adjust their offers very much in the first auctions held with such rules, the problem would likely increase over time. The RPM auctions are held every year. Market participants might approach the new market design somewhat tentatively in the first year or two, but over time it should be expected that conduct consistent with the incentives will increase. Note that in my example, some resources that did not engage in the conduct have regrets – that is, they would have a better outcome, had they pursued the conduct (lowering offer prices to clear in Stage 1, or raising offer prices to contribute to a higher clearing price in Stage 2). But no resources that engaged in either conduct have regrets. Thus, it should be expected that year to year, the distortion of offer prices would only increase.

71. As a result of these incentives and the resulting rational conduct, the RPM supply curves would become steeper and steeper over time (as suggested by the figures above). This is

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22 See proposed PJM Tariff, Attachment DD § 5.11 (Option A).
exactly the opposite of the result that is desired – gently sloped supply curves lead to competitive outcomes and relatively stable capacity prices over time, resulting in stronger investment incentives and weaker incentives to exercise market power. Steeper supply curves lead to more volatile prices, greater incentives to physically or economically withhold to raise prices, and weaker incentives for investors.

72. In dismissing the concerns about the distortion of offer price incentives, PJM states (as quoted above), “To the extent this posits that unsubsidized sellers would offer below their own net costs, so as to commit to provide PJM capacity for a full Delivery Year at a loss, such concerns are speculative, to say the least.” As my examples have shown, with realistic supply curves, there will be a large difference in the Stage 1 and Stage 2 prices when repricing is triggered, and sellers that lower their offer prices will not be at much risk of providing capacity “at a loss.”

73. PJM also suggests, in the above quote, that the price-setting offers may be from higher-cost existing units that are close to retirement rather than from new entrants. But the distortion of offer incentives is the same for existing or new units – if the likely Stage 2 price is attractive, it makes sense to lower the offer price in order to clear in Stage 1, if that is not too much of a reach. And if clearing in Stage 1 is too much of a reach, it makes sense to instead bid high to support a high Stage 2 clearing price, if there is affiliated generation in the auction.

74. Finally, I note that concerns about “bid shading” were raised in regard to ISO New England’s “CASPR” ( Competitive Auctions with Sponsored Policy Resources) mechanism, and the Commission was not persuaded that these concerns rendered the proposal unjust and unreasonable.23 However, the distortion of offer incentives that would result from PJM’s proposal

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23 162 FERC ¶ 61,205 Order on Tariff Filing, issued March 9, 2018 in Docket No ER18-619, P. 85.
is easily distinguished from the CASPR circumstances, and is much more serious. One key difference is that the bid shading concern around CASPR had to do with opportunities following the forward capacity auctions; the forward capacity auction retains the necessary feature that the price used to clear resources is the price the cleared resources will be paid. By contrast, under PJM’s Repricing Proposal, if repricing will be triggered, resources can be confident there will be a substantial wedge between the Stage 1 price that determines who clears, and the Stage 2 price that will actually be received.

3. **Fatal Flaw #3: Under PJM’s Repricing Proposal, the ultimate capacity price is arbitrary and not the result of a workable market mechanism**

75. The third fatal flaw in PJM’s Repricing Proposal has to do with the formation of the Stage 2 price that would be paid to all resources clearing in Stage 1. The Stage 2 clearing price would likely be set by an offer from a “competitive” resource (resources with actionable subsidies, that are repriced, are likely out of the money). Assuming the Stage 1 and Stage 2 prices are substantially different (which, as I have explained, is very likely to be the case when there are resources with actionable subsidies), the owner of the competitive resource that sets the Stage 2 price very likely knew the resource would not clear in Stage 1 and would not receive a CSO. Accordingly, the Stage 2 price would be set by an offer from a resource that had nothing at stake in the auction and in selecting its offer price (except for the incentive, described above, to inflate the offer price to support a higher Stage 2 clearing price, which only makes things worse). Thus, the Stage 2 price, which becomes a rate upon which billions of dollars in capacity payments will be based, is rather arbitrary and does not result from a workably competitive mechanism.
4. PJM’s Repricing Proposal raises additional concerns as applied to capacity zones, of which some are quite small and/or have concentrated ownership

76. My illustrative examples have pertained to the very large and relatively competitive RTO Region. PJM’s Repricing Proposal would apply to all zones modeled in RPM, of which, for the 2021/22 base residual auction there will be a total of fifteen. The modeled zones range in size from the Mid-Atlantic zone (about half the size of the RTO Region), down to DPL South, with a Reliability Requirement of 2,907 MW; eight zones are under 10,000 MW. Repricing would be triggered by 3.5% CRAS resources (350 MW, in a 10,000 MW zone), and any particular quantity of repriced resource will have a proportionally larger impact in smaller zones. Zonal supply curves can be quite steep, which would lead to relatively large differences between Stage 1 and Stage 2 quantity and price clearing results.

77. In addition, the smaller a zone, the larger the impact of any particular change in offer behavior. Ownership of capacity is generally much more concentrated in zones than in the RTO Region, with single sellers owning 50% or more of the capacity in some zones. Potential changes in conduct due to the PJM Repricing Proposal should be an even greater concern in zones.

78. PJM’s Repricing Proposal could potentially result in repricing, and resulting high capacity prices, in some zones, while repricing is not triggered, and capacity prices remain at moderate levels, in adjacent or surrounding zones. This could result in large differences in capacity prices between zones in which the actual capacity supply and demand circumstances may be very similar. This would send confusing and misleading price signals, and result in unwarranted differences in the cost to consumers.

D. Applicability and Duration of Mitigation

79. The final issue with regard to PJM’s Repricing Proposal (which is equally applicable to the MOPR-Ex proposal) has to do with the applicability and duration of repricing or
MOPR mitigation. As explained in Section III above, when the market has known well in advance that certain additional resources will be entering the market (whether “competitive”, state sponsored, or of any other type), market participants will have factored those resources into their estimates of the supply/demand balance and RPM clearing prices, and adjusted their entry and exit plans accordingly. Therefore, resources known well in advance do not affect price when they enter; they are already “baked in”. Repricing or MOPRing such resources distorts the RPM picture by effectively removing from the auction resources that are known to be present.

80. Furthermore, any repricing or application of the MOPR that is applied should last for no more than a few years, after which (if not sooner) the market will have fully absorbed the resource. The goal in applying repricing or the MOPR, as with any market intervention, should be to apply the minimum intervention for the minimum period, so that the market can return to pricing based on the true supply/demand balance without administrative interference.24

81. This concludes my affidavit.

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24 These concepts were proposed and discussed in the CCPPSTF process, but not included in either of PJM’s proposals. See, for instance, Wilson, James F., Proposed Path for Policy Resources based on Substantial Advanced Notice, CCPPSTF meeting September 11-12, 2017.
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SUMMARY

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal, Electricity Journal, Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982
BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
• Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
• Participated in a panel teleseminar on resource adequacy policy and modeling.
• Affidavit on opt-out rules for centralized capacity markets.
• Affidavits on minimum offer price rules for RTO centralized capacity markets.
• Evaluated electric utility avoided cost in a tax dispute.
• Advised on pricing approaches for RTO backstop short-term capacity procurement.
• Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
• Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
• Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
• Participated on a panel teleseminar on natural gas price forecasting.
• Affidavit evaluating a shortage pricing mechanism and recommending changes.
• Testimony in support of proposed changes to a forward capacity market mechanism.
• Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
• Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
• Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
• Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE


Principal

• Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
• Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
• Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
• Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
• Analyzed impacts and potential damages of natural gas migration from a storage field.
• Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
• Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
• Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
• Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
• Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
• Evaluated market power issues raised by a possible gas-electric merger.
• Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission (“FERC”) policy.
• Prepared an expert report on damages in a natural gas contract dispute.
• Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
• Prepared testimony evaluating natural gas procurement incentive mechanisms.
• Analyzed the need for and value of additional natural gas storage in the southwestern US.
• Evaluated market issues in the restrucutred Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
• Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
• Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
• Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
• Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power at the California border.
• Advised a major US utility with regard to the Federal Energy Regulatory Commission’s proposed Standard Market Design and its potential impacts on the company.
• Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
• Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
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• Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
• Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
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• Prepared market power analyses in support of electric generators’ applications to FERC for market-based rates for energy and ancillary services.
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- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy’s Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility’s generation assets and entitlements (power purchase agreements).
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- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
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- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.
Other consulting assignments in Russia, 1991–1994:
- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
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- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS


In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company’s Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.


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Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.


Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.


PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.


PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.


Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

PUBLISHED ARTICLES

Forward Capacity Market CONEfusio, Electricity Journal Vol. 23 Issue 9, November 2010.


Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.


OTHER ARTICLES, REPORTS AND PRESENTATIONS


Panel: Demand Response, Organization of PJM States Spring Strategy Meeting, April 9, 2018.


Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR; moderator; Infocast’s Mid-Atlantic Power Market Summit, October 24, 2017.


IMAPP “Two-Tier” FCM Pricing Proposals: Description and Critique, prepared for the New England States Committee on Electricity, October 2016.


Panel on Load Forecasting, Organization of PJM States Spring Strategy Meeting, April 13, 2015.


One Day in Ten Years? Resource Adequacy for the Smart Grid, revised draft November 2009.


Market Power: Definition, Detection, Mitigation, pre-conference workshop, with Scott Harvey, January 24, 2001.


Market Monitoring Workshop, presented to RTO West Market Monitoring Work Group, June 2000.


The Regional Transmission Organization’s Role in Market Monitoring, report for the Edison Electric Institute attached to their comments on the FERC’s NOPR on RTOs, August, 1999.


PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

April 2018
James F. Wilson  
Principal, Wilson Energy Economics  
4800 Hampden Lane Suite 200  
Bethesda, Maryland 20814 USA  
Phone: (240) 482-3737  
Cell: (301) 535-6571  
Email: jwilson@wilsonenec.com  
www.wilsonenec.com

SUMMARY
James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

- MS, Engineering-Economic Systems, Stanford University, 1982  
- BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
• Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
• Participated in a panel teleseminar on resource adequacy policy and modeling.
• Affidavit on opt-out rules for centralized capacity markets.
• Affidavits on minimum offer price rules for RTO centralized capacity markets.
• Evaluated electric utility avoided cost in a tax dispute.
• Advised on pricing approaches for RTO backstop short-term capacity procurement.
• Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
• Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
• Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
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• Participated on a panel teleseminar on natural gas price forecasting.
• Affidavit evaluating a shortage pricing mechanism and recommending changes.
• Testimony in support of proposed changes to a forward capacity market mechanism.
• Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
• Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
• Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
• Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE


Principal

• Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
• Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
• Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
• Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
• Analyzed impacts and potential damages of natural gas migration from a storage field.
• Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
• Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
• Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
• Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
• Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
• Evaluated market power issues raised by a possible gas-electric merger.
• Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.
• Prepared an expert report on damages in a natural gas contract dispute.
• Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
• Prepared testimony evaluating natural gas procurement incentive mechanisms.
• Analyzed the need for and value of additional natural gas storage in the southwestern US.
• Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
• Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
• Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
• Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
• Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
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PUBLISHED ARTICLES

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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

April 2018
Goggin Affidavit
I. Introduction

1. I am an independent consultant specializing in wholesale electricity markets and transmission policy. Previously, I have served as the Senior Director of Research for the American Wind Energy Association (AWEA). My biography can be found at https://gridstrategiesllc.com/about/.

2. I was asked to calculate the cost of the redundant capacity that would be procured due to PJM’s MOPR-Ex proposal. PJM’s MOPR-Ex proposal threatens to exclude nuclear and renewable resources that benefit from state policies from participation in the capacity market. My estimate calculates the rough costs should that occur.
II. PJM’s MOPR-Ex proposal would impose significant costs on consumers by procuring redundant capacity to replace capacity excluded from the capacity market.

3. I have determined that PJM’s MOPR-Ex proposal would result in the procurement of roughly between $14 billion and $24.6 billion of redundant capacity over roughly the next 10 years. These costs would utility be borne by PJM customers, translating to a cost of between $216 and $379 for each of the 65 million people in the PJM footprint.

4. These estimates assume that all resources receiving revenue pursuant to state programs would be excluded from participation in the capacity market under MOPR-Ex. The range in costs accounts for the fact that it was not possible to precisely determine whether resources procured as part of state Renewable Portfolio Standard (RPS) policies would be able to use the exemptions in the MOPR-Ex proposal to participate in the capacity market. The lower-end $14 billion cost assumes resources contracted under state RPSs are able to use the exemptions and participate in the capacity market. The higher-end $24.6 billion cost assumes those resources are barred from participation in the capacity market. It is likely that some, but not all, renewable resources will be able to use the exemptions, so the actual cost impact from the MOPR-Ex proposal will most likely falls between those two numbers.

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1 The roughly 10-year time horizon reflects the timeline on which most currently adopted RPSs and nuclear support policies will operate.

2 This cost per customer calculation is not intended to be a precise estimate of what retail customers would pay, which would require detailed modeling of impacts on capacity market clearing prices and a deep examination of how capacity costs are reflected through to retail rates in different states. Rather, it is simply intended to give a sense of the scale of PJM’s proposal with relation to its impact on retail customers.

3 The proposed exemptions are listed here: [https://www.pjm.com/-/media/committees-groups/committees/mc/20180125/20180125-item-02-mopr-ex-proposal.ashx](https://www.pjm.com/-/media/committees-groups/committees/mc/20180125/20180125-item-02-mopr-ex-proposal.ashx)
A. Calculating the lower-end cost impact from PJM’s MOPR-Ex Proposal

5. To determine the lower bound of cost impacts from PJM’s proposal, I considered only the capacity of the five Illinois nuclear plant in PJM and two nuclear plants in New Jersey. The nameplate capacity for the five Illinois nuclear plants in PJM – Braidwood, Byron, Dresden, LaSalle, and Quad Cities generation stations - total 11,276 MW. The nameplate capacity for the two nuclear plants in New Jersey that will continue to operate after 2019 - Hope Creek and Salem- total 3,631 MW. PJM calculates that nuclear plants have 98.397% availability for purposes of computing the share of nameplate capacity that receives credit in the capacity market, so those seven nuclear plants have an accredited capacity of 14,668 MW in PJM’s capacity market.

6. To calculate the cost of replacing that capacity, I assume that enough natural gas combustion turbines are built to provide an equal amount of accredited capacity. I assume the use of combustion turbines (CTs), instead of combined cycle (CC) power plants, because while CC plants are built to provide both energy and capacity, CTs are built almost entirely to provide capacity and not energy. This is evidenced by their very low capacity factors. Therefore, CTs better represent the cost of replacement capacity than CC plants do.

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4 As of the time of this filing, legislation to support New Jersey’s nuclear power plants and advance greater penetration of renewable resources remains pending. This analysis assumes that Governor Murphy will sign this legislation into law.
5 Clinton Power Station is located within the MISO footprint in Illinois.
6 https://www.pjm.com/-/media/planning/res-adeq/res-reports/2012-2016-pjm-generating-unit-class-average-values.ashx?la=en
7. PJM calculates that gas combustion turbines have a capacity market availability rate of 88.687%, so 16,539 MW of nameplate CT capacity would be needed to provide the equivalent 14,668 MW of accredited capacity. Using a regional CT installed cost of $848,500/MW, the midpoint of the $799,000-898,000/MW range reported by Brattle for the PJM region, indicates a cost of $14.033 billion for 16,539 MW of nameplate capacity. This $14 billion is thus the low-end estimate, assuming that all renewable resources are able to use the MOPR-Ex RPS exemption to participate in the capacity market and only nuclear plants receiving state subsidies are impacted by the MOPR-Ex proposal.

B. Calculating the higher-end cost impacts of PJM’s MOPR-Ex Proposal

8. The high-end estimate includes the associated capacity and replacement costs of the seven nuclear plants discussed above, as well as all renewable capacity that will be built under state RPS policies after this year (2018). This high-end estimate reflects the rough cost of MOPR-Ex without the RPS exemption. To determine the amount of RPS demand remaining pursuant to currently enacted or imminently pending state policies, I used the AWEA 2017 assessment database, which compiles data concerning these policies to inform members on the amount of market demand. I updated that assessment to account for pending legislation in New Jersey that is likely to be adopted imminently, Maryland state laws and regulations (to reflect Offshore Renewable Energy Credits (ORECs) that were awarded), and Illinois (because AWEA does not group Illinois with PJM for the purposes of its state RPS analysis).

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10 [https://www.awea.org/rps2017](https://www.awea.org/rps2017)
11 N.J. Stat. § 48:3-49 et seq. (last revision S.2313)
9. Maryland law calls for up to 2.5% of state electricity demand to be met by offshore wind, which would require just over 1.53 million MWh of ORECs. The state awarded 368 MW of ORECs to two projects in 2017, so those resources would be exempt from MOPR-Ex as they were contracted before the end of 2018. Assuming a 40% capacity factor (CF) for offshore wind, that leaves around 70 MW of remaining offshore capacity under the OREC program. At a 27% capacity value, that equals 18.83 MW of accredited capacity.

10. New Jersey recently updated its state RPS to include 3,500 MW of offshore wind, a solar carveout equal to 5.3% of electricity demand, and an overall RPS level of 50%. At 27% capacity value (per PJM’s capacity value above), the offshore requirement equates to 945 MW of accredited capacity. The 5.3% solar carveout equals 3,868,298 MWh of RECs or the annual production of 2,598 MW at the region’s typical 17% CF. This is equal to 1,559 MW of accredited capacity at PJM’s 60% capacity value.

11. After the offshore and solar carveouts, there would be 9,204,661 MWh of outstanding RECs that would likely be almost entirely provided by a mixture of onshore wind and solar. Historically, onshore wind has accounted for around 75% of New Jersey’s RPS procurement. I conservatively assume that that ratio will continue. However, if onshore wind captures a lower share than 75%, as is likely given recent cost trends for solar PV, then my estimate underestimates the capacity value of NJ’s RPS resource mix, as onshore wind’s 13%
capacity value is markedly lower than the capacity value of other renewable resources. Using a
75% onshore wind and 25% solar mix to meet the remaining RPS demand equals 2,440 MW of
nameplate onshore wind capacity and 1,545 MW of nameplate solar. This is equivalent to 317
MW and 927 MW of accredited capacity at PJM’s 13% and 60% capacity values.

12. The incremental renewable build under the Illinois RPS is driven through the
procurements of 3 million additional wind RECs and 3 million additional solar RECs through
2030. Using a 17% CF for PV,17 as assumed by the state, and a 37.6% CF for wind, as assumed by
AWEA’s report based on observed trends, yields nameplate capacities of 911 MW of wind and
2,015 MW of solar. This is equal to 118 MW and 1,209 MW of accredited capacity respectively.

13. In 2017, AWEA had projected that all parts of PJM, except Illinois had enough
remaining RPS demand to drive 10,500 MW of new wind capacity. However, AWEA assumed
that only 5,400 MW was likely to be met by wind, with the remainder likely met by solar due to
recent cost and deployment trends.18 Because the New Jersey and Maryland ORECs are
accounted for separately above, I subtracted from AWEA’s 5,400 MW of likely wind builds both
the 1,600 MW of new wind AWEA had projected would have been driven under the old NJ RPS
and the roughly 70 MW of remaining OREC capacity I accounted for above. That leaves 3,730
MW of remaining nameplate wind builds driven by RPS requirements, or at PJM’s 13% capacity
value, a total of 485 MW of accredited wind capacity.

14. To calculate the remaining non-wind RPS demand in the region, I also subtracted
out AWEA’s calculated 2,133 MW of wind-equivalent MW19 of new renewable capacity demand

18 https://www.awea.org/rps2017
19 AWEA calculates the required wind capacity assuming a regional wind capacity factor of around 34%.
remaining under the old New Jersey RPS. Subtracting out the other 3,800 MW of wind capacity (3,730 MW from preceding paragraph plus the remaining 70 MW of Maryland ORECs) leaves 4,567 MW of wind-equivalent RPS driven capacity left to be accounted for. I assumed solar provides this remaining non-wind RPS supply, given recent cost trends for solar and the fact that the region’s resource potential for other eligible renewables, like biomass, has already largely been developed. Since the regional capacity factor of solar is half that of wind (17% CF versus a 34% CF for eastern PJM), the 4,567 MW of non-wind capacity equals 9,134 MW of solar capacity. At PJM’s 60% capacity value, that equals 5,480 MW of accredited capacity.

<table>
<thead>
<tr>
<th>Nameplate Capacity (MW)</th>
<th>Capacity Value</th>
<th>Accredited Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NJ nukes</td>
<td>3,631</td>
<td>98.397%</td>
</tr>
<tr>
<td>IL PJM nukes</td>
<td>11,276</td>
<td>98.397%</td>
</tr>
<tr>
<td>MD post-2018 ORECs</td>
<td>70</td>
<td>27.00%</td>
</tr>
<tr>
<td>NJ generic RPS, wind</td>
<td>2,440</td>
<td>13.00%</td>
</tr>
<tr>
<td>NJ generic RPS, solar</td>
<td>1,545</td>
<td>60.00%</td>
</tr>
<tr>
<td>NJ solar carveout</td>
<td>2,598</td>
<td>60.00%</td>
</tr>
<tr>
<td>NJ offshore wind</td>
<td>3,500</td>
<td>27.00%</td>
</tr>
<tr>
<td>Incremental IL RPS demand 2019-2030, wind</td>
<td>911</td>
<td>13.00%</td>
</tr>
<tr>
<td>Incremental IL RPS demand 2019-2030, solar</td>
<td>2,015</td>
<td>60.00%</td>
</tr>
<tr>
<td>Other post-2018 state RPS demand, wind</td>
<td>3,730</td>
<td>13.00%</td>
</tr>
<tr>
<td>Other post-2018 state RPS demand, solar</td>
<td>9,134</td>
<td>60.00%</td>
</tr>
<tr>
<td><strong>Total Accredited Capacity (MW)</strong></td>
<td><strong>25,727</strong></td>
<td></td>
</tr>
</tbody>
</table>

15. As shown in the table above, these state-supported nuclear and RPS resources have a combined 25,727 MW of accredited capacity. at PJM’s 88.687% capacity value for gas CTs that is equal to 29,009 MW of nameplate CT capacity. Using an installed cost of $848,500/MW,\(^{20}\) this represents a cost of $24.614 billion. This $24.6 billion figure represents

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the high-end estimate of cost impacts from PJM’s MOPR-Ex proposal, assuming that no RPS-driven renewable resources are able to use the MOPR-Ex exemptions and are therefore barred from the capacity market.

This concludes my affidavit.
UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection LLC ) ER18-1314-000

Verification of Michael Goggin

On Behalf of the Sustainable FERC Project, Natural Resources Defense Council, and Sierra Club

I, Michael Goggin, declare under penalty of perjury that the attached affidavit is true and correct to the best of my knowledge, information and belief.

Michael Goggin

Execution Date: May 7, 2018
Exhibit C
Request for Rehearing of Clean Energy Advocates, July 30, 2018
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION  

Calpine Corporation, et al.  
Docket Nos. ER18-1314-000  
ER18-1314-001  
v.  
EL16-49  
EL18-178  
PJM Interconnection, L.L.C.  

REQUEST FOR REHEARING OF CLEAN ENERGY ADVOCATES  

Pursuant to section 313 of the Federal Power Act, 16 U.S.C. § 825l(a), and Rule 713 of the Federal Energy Regulatory Commission’s (“Commission” or “FERC”) Rules of Practice and Procedure, 18 C.F.R. § 385.713, Earthjustice, Natural Resources Defense Council, Sierra Club, Sustainable FERC Project, and Environmental Defense Fund (collectively “Clean Energy Advocates”) hereby request rehearing of the Commission’s Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act (June 29, 2018) (“PJM Capacity Market Order” or “Order”), which rejected the PJM Interconnection, LLC (“PJM”) proposed tariff revisions as not just and reasonable, held that existing capacity market tariff provisions are not just and reasonable, and instituted further proceedings to determine a replacement capacity market rate.  

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IV. Request for Rehearing

A. The Commission failed to articulate a reasoned basis for its finding that PJM capacity market rules are not just and reasonable and unduly discriminatory.

1. The Commission’s failure to sufficiently define the scope of its finding under section 206 provides an independent basis upon which the Order must be reversed.

2. Beyond conclusory statements that “competition” must be protected, the Order provides no articulation of how state programs render PJM’s capacity market rates unjust and unreasonable or unduly discriminatory.

   a. “Price suppression” by “uneconomic” resources is not a theory of market harm.

   b. The Commission fails to explain its exclusive focus on price suppression to the benefit of supply interests over customers

   c. The Commission does not adequately explain its departure from existing precedent, instead mischaracterizing the history of its MOPR decisions.

B. The Commission’s threadbare reasoning contradicts basic economic theory.

C. The Commission does not support its finding that PJM’s current rates are unjust and unreasonable with substantial evidence, and fails to respond to relevant data contradicting its theory that state programs harm the capacity market.

1. The Order does not provide substantial evidence that state programs threaten the integrity of the capacity market.

2. The Order fails to address relevant data contradicting its theory of market harm.

3. The Commission fails to grapple with evidence contradicting claims that RPS programs are “uneconomic.”

4. The Commission in particular lacks evidence of the magnitude of RPS programs’ impact on the capacity market.
D. The Commission’s finding that state implementation of climate policies renders wholesale markets unjust and unreasonable usurps the states’ rightful role under the Federal Power Act.


2. In ignoring valid property rights under state law, the Commission unduly discriminates against resources that earn revenue from RECs and ZECs.

E. The Commission should reconsider or, alternatively, clarify its overly broad assertion that resources supported by state policies are not similarly situated to so-called “competitive” resources.

V. Conclusion

I. Summary of Argument

The Commission’s Order triggers the upheaval and dramatic dismantling of existing PJM capacity market rules, abandons a more measured use of the minimum offer price rule in favor of an unprincipled and boundless aim of mitigating “price suppression,” and heralds a new era of growing tensions between wholesale markets and states pursuing their core duty to protect the public by deeming legitimate policies a threat to “market integrity.” The Order does so on the slimmest of rationales, offering up only six sparse paragraphs to justify the Commission’s sharp departure from its prior practice. The Commission embarks on this path in spite of an utter absence of evidence of an impending threat to the market’s ability to meet its core function of ensuring reliability at a just and reasonable cost. Indeed, to the contrary, all objective measures show the opposite trends to what one would expect if the market were under threat: booming investment; high investor confidence; and reserve margins in gross excess. Riddled with logical infirmities, the Order is not only bad policy, it also contravenes the basic requirements of the Federal Power Act and the Administrative Procedure Act.
The Commission must reverse its determination under Federal Power Act section 206 that “out-of-market support” in the form of state climate policies will cause unjust, unreasonable, and unduly discriminatory rates in PJM because the finding is not supported by sound reasoning, is contradicted by basic economic theory, and is not backed by substantial evidence. The Commission’s determination also infringes on states’ proper role under the Federal Power Act and discriminates among similarly situated resources in violation of the Federal Power Act.

First, the Commission has failed to articulate what makes a policy or action “out-of-market” support that may threaten functioning of the PJM capacity market. The Commission also does not identify what manner or degree of “out-of-market” support rises to the level of such a threat. Instead, the Commission shrugs off its core duty to define the nature of the problem in the market to a subsequent proceeding. The Commission declares that two specific state policies constitute problematic “out-of-market” support, but does not specify what makes these policies different from others that it accepts as properly affecting rates. The failure to delineate a clear boundary between acceptable and unacceptable market behavior is a violation of both the Federal Power Act – because it is a condition precedent to exercise of the Commission’s authority to set rates that it first issue a concrete and specific finding of a market failing – and the Administrative Procedure Act, because the lack of a clear rationale for the finding defies the mandate to exercise reasoned decisionmaking.

The Commission’s conclusory assertions that it must “mitigate” the effects of “price suppressive” and “uneconomic” behavior do not pass muster. At the heart of the matter, the Commission never explains how actions deemed “price suppressive” or “uncompetitive” are different from market behavior that is common in PJM today. More than one hundred thousand megawatts of capacity clears in the PJM auction at zero dollar bids, in some part driven by state
regulatory actions, but the Commission calls out just a few thousand megawatts of that capacity that is benefited by state climate policy as “price suppressive” and a threat. Market participants and other stakeholders are left to guess why, and have no way of knowing which, if any, of the constellation of federal and state policies shaping auction outcomes are also a market threat under the Commission’s murky new theory. Unrebutted record evidence reveals incentives of much greater magnitude (scale of support) and sweep (capacity affected) that would have the same theoretical impacts on bidding behavior of conventional generators, yet the Commission’s Order targets only two state programs: payments for the value of zero-emissions nuclear generation (or Zero Emissions Credits, “ZECs”) and state mandates to purchase a certain percentage of renewable energy (Renewable Portfolio Standards, “RPS”). The Commission has failed to show that its line-drawing around these two programs is not arbitrary.

Nor does the Commission’s further justification that some bidding behavior is a reflection of “true costs” and therefore “economic” have any explanatory value. The Commission has long treated costs and benefits that accrue because of differing state regulatory contexts (e.g., tax incentives, tradable emission allowances, sale of non-FERC jurisdictional products) as part of an “economic” offer. The Commission never explains why climate policy is any different. This failure to justify a radical new approach of targeting some state legal regimes as providing advantages that are “uncompetitive” is even more egregious in light of the long and significant reliance of states, investors, and other stakeholders on the prior practice of recognizing state regulatory differences as part of the competitive backdrop.

The Commission also fails to explain its exclusive focus on price suppression and not price inflation. By its own theory, any divergence from a resource’s “true costs” is a market threat (notably, the Commission does not hinge its finding of threat to any measure of the scale of the
incentive). Yet the Commission Order limits its concern to state actions that “suppress,” rather than raise, prices. The one-sided focus on policing incentives that will lower prices, by definition, elevates supply interests over customer interests. The Commission cannot so blatantly disregard its core duty under the Federal Power Act to protect customers.

In the same vein, the Commission’s specific explanation of its abandonment of prior precedent on the scope of the minimum-offer is also inadequate. The Commission fails to squarely confront its own prior rationale for limiting the rule to resources that are likely to have the largest potential to shape market outcomes (which, for multiple reasons, does not include renewable resources), and never presents a new, coherent framework for applying mitigation to capacity market bids.

Second, the slim logic that the Commission does offer for its determination faces the high hurdle that it conflicts with basic economic principles. Economics 101 teaches us that government policies that address externalities, whether by pricing negative externalities or incenting the positives ones, *enhance* market efficiency, not undercut it. The Commission never reconciles with this foundational economic principle its finding that state climate policies, particularly programs that are objectively efficient in achieving their aims, *distort* market outcomes. The Commission cannot base its finding that the market is under threat on logic that is so wholly unmoored from simple economics.

Third, the Commission lacks the factual record to support its Federal Power Act section 206 determination. The record is bare of analysis to support the Commission’s theory that these two state climate policies harm the market. Moreover, the Commission fails to address evidence and reasoning that directly contradicts its theory of market harm. The Order simply ignores well-reasoned explanations that the targeted state actions would *not* result in the projected drop in
market price, and indeed, could result in *increases* in capacity market clearing prices. Uncontroverted evidence in the record also shows the Commission is wrong on the facts with respect to core assumptions underpinning its theory of market harm. Objective measures of market performance do not manifest any of the predicted harms, though state RPS programs have existed since the inception of the PJM capacity market and have increased in ambition periodically thereafter. And, while the Commission bases its findings that state climate policies pose a threat on the “changed circumstances” of their expanded reach to larger quantities of capacity, it never confronts the substantial record evidence that government incentives of greater scale have shaped market outcomes for decades without triggering a market crisis. State climate policies do not represent a new high water mark in terms of conveying advantages to certain kinds of new entrants or deterring exit of favored resources, and their scale cannot justify different treatment.

The Commission also fails to grapple with evidence specifically contradicting its assertion that state RPS programs pose a threat. It is simply false that these policies are “uncompetitive” – potentially eligible resources have no guarantee of support and must instead compete in markets or competitive procurement processes to qualify for credits. Moreover, evidence that state RPS targets for renewable energy procurement are growing more ambitious is not tantamount to evidence that the magnitude of *support* for RPS resources participating in the PJM capacity is growing. Nor, in a further logical leap, do increasing RPS targets show that such support has increasing effect on capacity market outcomes. Renewable resources continue to face significant barriers to participation in the PJM capacity market, an outcome that is likely to persist without Commission action. RPS programs also set forth cost containment mechanisms, alternative compliance mechanisms, and opportunities to satisfy requirements via resources not within the PJM footprint – none of which are accounted for in the Commission’s projections.
Fourth, the Commission oversteps its role under the Federal Power Act by overturning the determinations of competent state regulators as to the value of environmental externalities. The Order, in effect, concludes that assigning any other value other than zero to an environmental attribute of capacity is “uneconomic.” As Commissioner Glick explained in his dissent, “[i]t is not the Commission’s role under the [Federal Power Act (“FPA’’)] to create an electricity market free from governmental programs aimed at public policy considerations.”¹ Rather, “[t]he FPA is clear that the states, not the Commission, are the entities responsible for shaping the generation mix.”² Moreover, the consequence of this overruling of state judgment is the arbitrary and undue discrimination of resources under state RPS and ZEC programs. While other resources continue to benefit from the advantages due to other state legal and regulatory actions (generous retail rates of return; tax and economic development incentives; policies that decrease fuel costs; uneven regulatory requirements and the like), resources affected by the targeted state climate policies are forced out of the capacity markets by rules that designate their offers as “uneconomic.” The Commission does not justify this arbitrary respect for some state legal regimes but disregard for other property rights under state law.

Finally, while Clean Energy Advocates do not request rehearing of the Commission’s rejection of PJM’s proposed tariff changes as unjust and unreasonable (a finding we agree with on other grounds), the Commission must reconsider one overly broad sentence within those findings that could potentially have implications far beyond the scope of this proceeding. The consolidated proceedings never contemplated the interactions of state policy within other RTO/ISO footprints, nor more than peripherally their relationship to delivery of energy or ancillary services. Yet,

¹ Order (Glick, R. dissenting at 5).
² Id. (Glick, R. dissenting at 2).
perhaps by drafting error, paragraph 68 of the Commission’s Order would appear on its face to reach conclusions beyond the context of the PJM capacity market. Though Clean Energy Advocates dispute that these findings are supported even as applied within the PJM capacity market, there can be no serious contention that this proceeding, with its record limited to the PJM context, could support findings beyond the PJM capacity market.

For the foregoing reasons, Clean Energy Advocates respectfully request the Commission reverse its determination under Federal Power Act section 206 that PJM’s existing tariff renders capacity market rates unjust, unreasonable, or unduly discriminatory. Clean Energy Advocates also request the Commission reverse or narrow the findings of paragraph 68 of the Order.

In the alternative, if the Commission will not reverse its section 206 finding, Clean Energy Advocates request the Commission convert the determination into a preliminary finding combined with a show cause proceeding. Such a show cause proceeding would provide a forum for the further deliberation that is clearly needed before reaching a well-supported determination regarding the threats, if any, posed to PJM’s capacity market. The additional time for deliberation would also avert the impending chaos and uncertainty triggered by the Commission’s Order to redesign core aspects of PJM’s capacity market rules within 60 days.

II. Statement of Issues

Pursuant to Rules 203(a)(7) and 713, 18 C.F.R. §§ 385.203(a)(7) and 385.713 (2018), Clean Energy Advocates present the following identification of errors and statement of issues:

The Commission violated the Federal Power Act and Administrative Procedure Act in finding that PJM’s existing Tariff is unjust and unreasonable and unduly discriminatory. In particular:

1. The Commission failed to articulate a reasoned basis for its finding that capacity market rules are unjust and unreasonable and unduly discriminatory.
a. The Commission failed to sufficiently define the scope of its finding, violating the requirement under section 206 of the Federal Power Act to proceed in stepwise fashion and move to create a replacement rate only after pinpointing factors causing rates to be unjust, unreasonable, or unduly discriminatory.³

b. Beyond conclusory statements that “competition” must be protected, the Order provides no articulation of how state programs render PJM’s capacity market rates unjust and unreasonable or unduly discriminatory.⁴

2. The Commission’s threadbare reasoning contradicts basic and widely accepted economic principles.⁵

3. The Commission does not support its finding that PJM’s current rates are unjust and unreasonable with substantial evidence, and it fails to respond to relevant data contradicting its theory that state programs harm the capacity market.⁶

4. The Commission’s finding that state implementation of climate policies renders wholesale markets unjust and unreasonable usurps the states’ rightful role under the Federal Power Act.⁷

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⁵ Mobil Pipe Line Co. v. FERC., 676 F.3d 1098 (D.C. Cir. 2012).
⁷ 16 U.S.C. §§ 824(a), 824(b), 824d, 824e; Connecticut Dep’t of Pub. Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2009) (“The ‘Installed Capacity Requirement’ is misnamed because increasing it doesn’t actually ‘require’ anyone to ‘install’ any new ‘capacity’ at all. State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of
5. The Commission erred in broadly asserting that resources supported by state policies are not similarly situated to so-called “competitive” resources.

III. Background

The following section focuses narrowly on the procedural history and other background relevant to the request for rehearing. Clean Energy Advocates Protest provides a more fulsome factual background, including information about the state laws and policies affected by the Order, the stakeholder process leading to this proceeding, and the history of the minimum-offer-price-rule in PJM.

A. Procedural History

In March 2016, Calpine Corporation and a group of other generation owners filed a complaint under section 206 of the Federal Power Act. The complaint focused on the alleged market impacts of a then-proposed action by the Public Utilities Commission of Ohio (“PUCO”) to allow approximately six gigawatts of capacity owned by AEP and FirstEnergy subsidiaries to recover costs under proposed affiliate power purchase agreements (“akin to traditional cost-of-service, rate of-return regulation”) from retail ratepayers. Complainants argued that the new threat of the capacity market bidding incentives created by the generous rate-recovery warranted extension of the Minimum Offer Pricing Rule (“MOPR”), which only applied to new gas-fired generation facilities without direct interference from the Commission.”; WSPP Inc., 139 FERC ¶ 61,061 (Apr. 20, 2012); Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288 (2016).


9 See Clean Energy Advocates Protest at 9-23.


11 Id. at 25-26.
resources, to existing units participating in the capacity market.\textsuperscript{12} PUCO did not ultimately move forward with the power purchase agreements as proposed, and Complainants submitted an amended filing targeting the alleged market effects of Illinois legislation providing for the procurement of zero-emissions credits (“ZECs”).\textsuperscript{13} Complainants maintained that the Illinois policy would affect as much as 2,800 megawatts of existing nuclear capacity in the PJM market, argued that the ZEC program would pose the same threat to the PJM capacity market as the PUCO proposal, and reiterated its request to expand the scope of the MOPR to existing resources.\textsuperscript{14} Neither the original nor the amended complaint mentioned state Renewable Portfolio Standards (“RPS”) as a policy posing similar concerns.

The Commission had not acted on the Calpine Complaint by the time that PJM filed its own proposed tariff revisions that aimed to address the interaction of state public policy with the PJM capacity market. PJM’s filing to FERC was preceded by a stunted and contentious stakeholder process, in which a majority of stakeholders resoundingly rejected the notion that the capacity market faced an urgent threat requiring changes to market rules.\textsuperscript{15} Nevertheless, on April 9, 2018 PJM overrode stakeholder judgment and filed before the Commission two alternate tariff proposals, each of which would bring sweeping changes to PJM’s capacity market construct,

\textsuperscript{12} Id. at 2.
\textsuperscript{13} Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint, EL16-49 (Jan 9, 2017).
\textsuperscript{14} Id. at 7, 10-11, 16.
\textsuperscript{15} See Clean Energy Advocates Protest at 25-30 (describing frustrations of many stakeholders with a process that was too rushed, failed to identify a clear problem in the market, and ignored majority stakeholder support for the status quo).
known as the Reliability Pricing Model (“RPM”). The first and PJM-preferred option, Capacity Re-pricing, PJM styled as “accommodating” state policy actions. The second, preferred by the Independent Market Monitor and dubbed “MOPR-Ex,” PJM openly acknowledged was “punitive” to states whose policies fell within its scope. Clean Energy Advocates timely intervened and opposed both sets of tariff changes, submitting evidence and expert reports demonstrating the proposals would result in unjust and unreasonable rates and undue discrimination to consumers and/or resources.

On June 29, 2018, the Commission issued the Order. In addition to its substantive determinations, described below, the Order consolidated the Calpine Complaint proceeding (EL16-49) with the PJM section 205 filing proceeding (ER18-1314) and instituted sua sponte and further consolidated a third proceeding (EL18-178) under Federal Power Act section 206.

B. Summary of the Order

The Commission issues three legal findings in its Order. It first considers and then rejects each of the Capacity Repricing and MOPR-Ex tariff revisions proposed by PJM as unjust and unreasonable under Federal Power Act section 205. The Commission also concludes on the basis

17 PJM Filing at 6.
18 Id. at 53, 56, n.138.
19 See Clean Energy Advocates Protest; see also Order at P 28, 30 (granting Clean Energy Advocates’ timely-filed motions for intervention).
20 Order at P 149.
21 Id. at PP 32-106.
of the consolidated proceedings that “PJM’s existing Tariff is unjust and unreasonable and unduly discriminatory” pursuant to Federal Power Act section 206.22

The Commission’s findings rejecting PJM’s proposals under section 205 of the Federal Power Act are largely irrelevant to the instant request for rehearing and are not described at length here. One finding related to the Commission’s rejection of Capacity Repricing is pertinent. Among other reasons for rejecting the proposal, the Commission concludes that “it’s unjust and unreasonable, and unduly discriminatory or preferential, for a resource receiving out-of-market payments to benefit from its participation in the PJM capacity market, by not competing on a comparable basis with competitive resources.”23 The Commission explains that resources that, under the terms of the Capacity Repricing tariff revision, receive a “Material Subsidy” can rely on that revenue to submit an offer below its “true” going-forward costs.24 Allowing such resources to receive the same clearing price as resources that do not receive such revenue and to benefit from a higher clearing price in the second stage of the auction25, the Commission concludes, “unduly discriminates against competitive resources.”26 While the Commission’s finding unambiguously responds to the particular terms of Capacity Repricing, the subsequent sentence is less clear. The Commission states, “[t]he receipt of out-of-market support is a difference that requires different ratemaking treatment when such support has a material effect on price or cannot otherwise be justified by our statutory standards.”27 Whether the Commission intended to restrict the statement

22 Id. at PP 107-175.
23 Id. at P 66.
24 Id.
25 Id. at P 67.
26 Id. at P 68.
27 Id.
solely to the PJM capacity market is not clear, nor are the circumstances that the Commission believes warrant different ratemaking treatment.28

Clean Energy Advocates’ rehearing request focuses primarily on errors underlying the Commission’s determination under section 206 of the Federal Power Act. In finding that PJM’s existing tariff is not just and reasonable, the Commission asserts that, “records in both cases demonstrate that states have provided or required meaningful out-of-market support to resources in the current PJM capacity market, and that such support is projected to increase substantially in the future.”29 The Commission does not define “meaningful” support, or “out-of-market support.” The Commission asserts that it “need not” address the scope of “out-of-market support” and seeks comments on the scope of a definition of the term.30 However, the Commission concludes that ZEC and RPS programs constitute “out-of-market support” and explains that its finding that PJM’s existing tariff is not just and reasonable is based solely on those two state programs.31

To back its assertion that support is increasing substantially, the Commission points to (i) the Illinois ZEC program; (ii) the New Jersey ZEC program; (iii) offshore wind programs in Maryland and New Jersey; and (iv) estimates of capacity needed to meet state RPS requirements within PJM in 2018 and 2025.32 The Commission claims that the “out-of-market support” provided by ZEC and RPS programs “will significantly affect the PJM capacity market” on the basis of

28 The “or” is confusing, as it is not clear whether both a material effect on price and separately a lack of other justification warrant different treatment, or such treatment is called for only when both conditions are true together.
29 Id. at P 149.
30 Id. at P 2, n.1.
31 Id.
32 Id. at PP 151-152.
estimates of the $/MW-day value of the support provided by the programs, which in some instances exceeds the RPM clearing price in a recent auction. The Commission did not define a “significant effect” on the market. It asserted that the level of payments in PJM are high enough to “significantly affect” a recipient resource’s decision to remain in operation.

The Commission also found that two aspects of MOPR that it had previously upheld as just and reasonable must now be altered: the limits on MOPR’s application to only new and only gas-fired resources. The Commission justified this finding on “changed circumstances” in PJM, by which it referred to an increase in programs providing out-of-market support such as the ZEC program. The Commission emphasized the proliferation of out-of-market support to older, uneconomic resources and asserted that retaining such resources results in price suppression and may displace resources from the market. The Commission therefore determined the exclusion of existing resources from MOPR was no longer warranted. The Commission recognized that gas-fired resources are more capable of suppressing price than others, but found that “they are not the only resources likely or able to suppress capacity prices.” Citing to a decision expanding the MOPR in the ISO New England, Inc. (ISO-NE), the Commission stated that “resources receiving out-of-market support are capable of suppressing market prices regardless of intent.”

33 Id.
34 Id. at P 154.
35 Id. at PP 153-155.
36 Id. at P 153.
37 Id. at P 154.
38 Id.
39 Id. at P 155.
40 Id.
Commission stated that it could no longer assume there is a difference among resource types for the purpose of determining MOPR’s scope.\textsuperscript{41}

Finally, the Commission reiterated its finding that “out-of-market payments” have reached levels that “significantly impact” market prices and the “integrity of resulting price signals.”\textsuperscript{42} On this basis, the Commission concluded that the PJM tariff is unjust and unreasonable.\textsuperscript{43}

The Commission did not make a final determination of the replacement rate, instead describing its “preliminary” finding with regard to two potential modifications of the PJM tariff and initiating a paper hearing to further support a decision.\textsuperscript{44} Recognizing that a number of details would need to be addressed to implement the proposed replacement, the Commission solicited input on a series of issues.\textsuperscript{45} The Commission set a 60-day deadline for initial comments, with an additional 30-days for reply, and indicated its intent to issue a final decision by no later than January 4, 2019.\textsuperscript{46}

Two Commissioners issued dissents, and one Commissioner issued a concurring opinion. Commissioner LaFleur dissented, noting that she views tailored regional solutions as the best path forward to addressing the tensions between state policies and wholesale capacity market objectives.\textsuperscript{47} Commissioner LaFleur strongly disagreed with the majority decision finding PJM’s existing tariff unjust and unreasonable and setting a paper hearing to flesh out the majority’s

\textsuperscript{41} Id.
\textsuperscript{42} Id. at P 156.
\textsuperscript{43} Id.
\textsuperscript{44} Id. at PP 157-172.
\textsuperscript{45} Id. at 164-171.
\textsuperscript{46} Id. at 172.
\textsuperscript{47} Order (LaFleur, C. dissenting at 1).
proposed replacement. Commissioner LaFleur voiced alarm that the majority intends to adopt “the most sweeping changes to the PJM capacity construct since the market’s inception more than a decade ago” within the short timeframe of the paper hearing, and is particularly troubled that the decision “hamstrings” the Commission’s ability to engage with states regarding the replacement rate.

Commissioner Glick issued a separate dissent strongly disagreeing with the majority decision. Commissioner Glick disagreed with the majority’s conclusion that failure to “mitigate” state’s efforts to shape the generation mix results in unjust and unreasonable rates, where the targeted programs are “precisely the sort of actions that Congress reserved to the states when it enacted the FPA.” He explained that by mitigating these state policies, the Commission is directly interfering with state efforts to shape the generation mix. Commissioner Glick pointed to the pervasive effect of government subsidies in the energy markets for more than a century, including those with a far greater “price suppressive” effect than the programs targeted by the Order. He concludes that the majority is thus “picking and choosing which policies to frustrate and which to willfully ignore.” Commissioner Glick also disagreed with the majority because it had failed to meet its burden to show that PJM’s tariff is unjust and unreasonable. He explained

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48 Id. at 3.
49 Id.
50 Order (Glick, R. dissenting at 1).
51 Id.
52 Id. at 5.
53 Id. at 6-8.
54 Id. at 6
55 Id. at 1.
that the majority vacillates in its rationale, supports its finding on theory that is not “based upon reasonable predictions rooted in basic economic principles,” and, instead of substantial evidence, offers speculation that is an insufficient basis to find the existing PJM tariff unjust and unreasonable. Finally, Commissioner Glick voices concern that the significant questions left open by the Order cannot be meaningfully answered within the time provided by majority.

Commissioner Powelson issued a separate concurring opinion. His opinion reiterates the majority’s finding that there is a problem in the market, recognized that there is no “one-size-fits-all” solution. Commissioner Powelson distinguished between the problem in PJM as one of an accommodation of existing state-supported resources and that in ISO-NE, which is an accommodation of new state-supported resources. He explained that the proposed replacement rate is solution that is “appropriate for the unique set of circumstances in the PJM region.”

C. Clean Energy Advocates are Aggrieved Parties

Clean Energy Advocates are aggrieved parties under section 313(b) of the Federal Power Act. Clean Energy Advocates actively engage in the PJM stakeholder process and pursue the advancement of clean energy policies throughout the PJM region. Members of Clean Energy Advocates’ organizations are located within the PJM footprint, and when bulk power prices increase, will face more expensive energy bills. The Order results in the mitigation of capacity

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56 Id. at 4 n.6.
57 Id. at 10-11.
58 Id. at 11.
59 Id. at 12-13.
60 Order (Powelson, R. concurring at 2).
61 Id.
62 Id. at 2.
resources that would not otherwise occur and, by the Commission’s own logic, will result in higher capacity market clearing prices. As such, Clean Energy Advocates are directly and concretely harmed by the Order.64

**IV. Request for Rehearing**

The Commission’s finding under section 206 of the Federal Power Act fails to meet the legal requirements of the Federal Power Act and Administrative Procedure Act. The request for rehearing first addresses the Commission’s failure to adequately explain its rationale in finding that the current PJM tariff is not just and reasonable. Next, Clean Energy Advocates show the inconsistency of the Commission’s theory with basic economic principles. Third, the request sets forth the insufficiency of the evidence in support of the Commission’s determination, including lack of evidence to support essential assumptions underlying the Commission’s theory, failure to grapple with alternative theories, and unrebutted record evidence that contradicts the Commission’s factual findings and rationale underpinning the determination. Fourth, the request focuses on the consequences of the Commission’s arbitrary targeting of state climate policies, including the overstepping of the Commission’s proper role under the Federal Power Act, the improper frustration of the state’s reserved role in determining the generation mix, and undue discrimination against certain resources. Last, the request addresses one aspect of the Commission’s rejection of the Capacity Repricing proposal as unjust and unreasonable, which appears to reach conclusions much broader than the scope of the matters before the Commission in this proceeding and should therefore be reversed or, at minimum, narrowed.

64 *See Am. Pub. Gas Ass'n v. FERC*, 587 F.2d 1089, 1094 (D.C. Cir. 1978) (parties are aggrieved at the point of announcement of the new policy and review need not await application to a specific instance of the market behavior).
A. The Commission failed to articulate a reasoned basis for its finding that PJM capacity market rules are not just and reasonable and unduly discriminatory.

While the Commission purports to find that PJM’s capacity market rates are unjust, unreasonable, and unduly discriminatory, it fails to explain how, precisely, that is so. Rather, the Commission postpones the task of defining the scope of its section 206 finding to a subsequent proceeding it has ordered to establish a replacement rate. In so doing, the Commission violates its duty under section 206 of the Federal Power Act to order a replacement rate only after finding that existing rates are not just and reasonable and/or unduly discriminatory. For the same reason, the Order runs afoul of the Administrative Procedure Act’s core mandate to “articulate a satisfactory explanation for its action including a ‘rational connection between the facts found and the choice made.’”

The Commission’s minimal, six paragraph-long determination is inadequate because it makes a logical leap from the increasing ambition of state climate policies to purported (and as discussed in the next section, unfounded) market harm. Simply deeming these policies “price suppressive” is not sufficient. The Commission has long concluded that other market behavior and state actions that would have the same “price suppressive” effects do not threaten markets or render rates unjust and unreasonable, and it must explain its rationale and convincingly demonstrate that its contrary conclusion with respect to state climate policy is not arbitrary. Moreover, in overturning years of prior practice that has engendered significant reliance interests, the Commission must take particular care to explain its departure.

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\[66\] *Encino Motorcars, LLC*, 136 S. Ct. at 2126; *FCC*, 556 U.S. at 515.
1. The Commission’s failure to sufficiently define the scope of its finding under section 206 provides an independent basis upon which the Order must be reversed.

According to the Commission, “states have provided or required meaningful out-of-market support to resources in the current PJM capacity market,” and such “subsidies allow resources to suppress capacity market clearing prices, rendering the rate unjust and unreasonable.” Yet, the Commission leaves the critical details about the meaning of this statement entirely ambiguous. It does not define “out-of-market support” or “subsidy,” or explain what renders such support “meaningful.” Indeed, the Commission specifically avoids providing a definition of such terms in its Order, seeking comment on an appropriate definition as part of its replacement rate proceeding. It refers vaguely to “various state programs,” or “certain PJM states” who have passed policies, without ever providing even a rudimentary list of such programs that might allow stakeholders to begin to distinguish among the many different types of support cited by parties to this proceeding in the record to determine whether they are covered by the scope of the Order. The only guidance given is that ZEC policies and RPS programs (themselves left undefined) are two examples of “[o]ut-of-market payments.”

Rather than identifying the supposed problem rendering rates unjust and unreasonable and unduly discriminatory, the Commission improperly leaves this task to a paper hearing process it has initiated “to make a final determination regarding the just and reasonable replacement rate for

67 Order at P 149.
68 See Order at P 1 n.1.
69 Id. at P 151.
70 Id. at P 156.
71 Id. at P 1 n.1.
the PJM Tariff.” The Commission states that its proposed replacement rate should include an “expanded MOPR, with few or no exceptions.” But while it dictates vaguely that such a MOPR should cover “out-of-market support to all new and existing resources, regardless of resource type,” it requests comment on the meaning of that phrase through its paper hearing process, calling for the parties to “address the … the appropriate scope of out-of-market support to be mitigated by the expanded MOPR.” The Commission obscures the fact that the scope of the MOPR to be proposed by parties in this exercise will also define the scope of the alleged problem. Section 206 of the Federal Power Act bars the Commission from ordering a replacement rate in this manner before it has defined the scope of the section 206 violation.

“[U]nlike section 205, section 206 mandates a two-step procedure that requires FERC to make an explicit finding that the existing rate is unlawful before setting a new rate.” As the D.C. Circuit has explained, “a finding that an existing rate is unjust and unreasonable is the ‘condition

72  Id. at P 157.
73  Id. at P 158.
74  Id.
75  Order at PP 164-65.
76  Emera Maine, 854 F.3d at 24 (emphasis added). The stepwise requirement of section 206 that mandates a threshold finding to be made before the replacement rate is ordered is even more sensible in this case, because given the lack of any rational distinction between climate policies and other factors affecting PJM’s market, the proceeding to adopt the replacement rate will inevitably reveal that state climate policies such as renewable portfolio standards cannot reasonably be distinguished from other policies set by states and agencies other than FERC. Should the Commission’s finding that such policies render rates unjust and unreasonable stand, it will be placed in an impossible position of needing to establish a replacement rate, yet finding none that are just and reasonable and not unduly discriminatory (because any rate mitigating the state policies identified by FERC will unduly discriminate between resources supported by such policies and resources whose cost and revenues are affected by other policies that impact capacity market outcomes in the same manner).
precedent’ to FERC’s exercise of its section 206 authority to change that rate.” Further, under section 206, the scope of the Commission’s authority to establish a replacement rate is guided by the scope of the finding that current rates are unjust and unreasonable. The Commission may not, for instance, order sweeping changes to a grid operator’s tariff upon finding that a minor provision violates the Federal Power Act. It follows that the Commission may not rely on a rate replacement proceeding to define the scope or extent to which existing rates are not just and reasonable. Were this not so, the agency could write itself a blank check through an ambiguous section 206 finding that, like today’s order, leaves a near-infinite range of potential outcomes on the table.

2. **Beyond conclusory statements that “competition” must be protected, the Order provides no articulation of how state programs render PJM’s capacity market rates unjust and unreasonable or unduly discriminatory.**

The Commission also fails to articulate a reasoned basis for its decision and is therefore arbitrary and capricious. While the Commission’s logic is murky, the Order targets ZEC and RPS programs specifically. By concluding that state climate policies pose a threat to market competition, the Commission departs without adequate explanation from a long history of treating the patchwork of state regulation as part of the competitive backdrop in which markets function. In adopting its new, apparently exclusive, focus on the potential for “price suppressive” effects, the Commission fails to explain why the targeted state policies pose a threat while it has long accepted other, equally “price suppressive” market behavior in the PJM capacity market. As

77 *Id.* at 25.
78 *See Colorado Office of Consumer Counsel, 490 F.3d at 956* (explaining that the scope of the replacement rate ordered by the Commission is appropriately tailored to the scope of the Commission’s finding that rates are unjust and unreasonable).
79 Including, for example, low or zero offers into the capacity market by units with a guaranteed rate of return in regulated retail jurisdictions; federal and state preferences for conventional generation in the form of tax incentives, subsidies, guarantees, etc.; and low or zero
Commissioner Glick explains in his dissent: the Commission’s “shifting justifications . . . call into question whether [the decision] is the product of reasoned decision-making rather than a straightforward effort to prop up prices for certain resources.” The Commission further fails to explain its preoccupation with certain “price suppressive” state policies, where policies that tend to increase resource offers would similarly have effects on market prices and the relative competitiveness of resources; and a one-sided focus on increasing prices elevates supply interests to the harm of customers. Finally, the Commission fails to adequately explain its departure from its prior precedent regarding the scope of the MOPR, mischaracterizing the history of its prior orders rather than acknowledging and rationalizing its dramatic change in course.

a. “Price suppression” by “uneconomic” resources is not a theory of market harm.

The language underlying the Order’s section 206 finding that rates are not just and reasonable and unduly discriminatory consists solely of general platitudes, not a true theory of market harm. The essence of the Commission’s finding, contained in just six short paragraphs of the Order, is that “out-of-market payments” allow “resources that the market does not regard as economic” to displace “competitive” resources. But this circular reasoning is little more than a talismanic phrase. The Commission must explain its rationale that state climate policies are harmful while others are not. The Commission has not confronted logical arguments advanced by Clean Energy Advocates and other stakeholders that such policies are no different economically than any other federal or state policy that affords a competitive advantage to some resources and offers into the capacity market due to revenue from non-FERC jurisdictional sales, such as bottom ash, fly ash, steam, tradable emission credits, and so on.

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80 Order (Glick, R. dissenting at 4 n.6)
81 Order at P 132.
not others. Moreover, the Commission must offer an explanation in light of its long practice of recognizing advantages conveyed by state legal regimes, such as emissions credits or lower tax rates, as a valid part of a resource’s competitive offer.

The Commission’s conclusory assertion that price suppression caused by “state choices to support certain resources or resource types is indistinguishable from that triggered through the exercise of buyer-side market power” is not a reasoned explanation. Nor are the Commission’s vague assertions that the “integrity” and “effectiveness” of the capacity market, which the Commission never defines, have been compromised. Likewise, the Commission’s (as discussed herein, unsubstantiated) assertion that the targeted state programs have reached new magnitudes that constitute “changed circumstances” falls short. Without a reasoned explanation


84 Order at P 155.

85 See Order (Glick, R. dissenting at 6) (citing Order at PP 1, 150, 157, 161-62).

86 TransCanada Power Mktg. Ltd., 811 F.3d at 13 (“talismanic” description of a program as “competitive” without further explanation “does not advance reasoned decision making”).

87 See infra Section IV.C. The Commission fails to engage with the evidence put forward by the Clean Energy Advocates and others that the magnitude of so-called “out-of-market” support has not increased when accounting for other relevant policies, and that the PJM capacity market has been deeply influenced by external policies since its inception.

88 Order at P 153.

89 National Fuel, 468 F.3d at 844 (If the Commission points to changed market conditions that create new threats, “it will need to elucidate how those developments relate to and justify the promulgation of costly prophylactic rules.”).
as to why these policies are problematic in the first place, evidence of their increasing ambition is immaterial.

The Commission elaborates to a somewhat greater extent its concern that state climate policy “increases the ability of even uncompetitive existing resources, for whom a competitive offer would be significantly higher than zero, to submit offers into the PJM capacity market that do not reflect their actual costs.”\(^{90}\) In the same vein, the Commission appears to suggest the competitive advantage conferred by state climate policy is not “the result of competitive market forces” and therefore problematic.\(^{91}\) Yet it is uncontroverted that submitting zero dollar offers into the PJM capacity market is common practice, and that such market behavior is often enabled by unique state regulatory context distinct from climate policy.\(^{92}\) The Commission provides no explanation why state climate policies pose a “price suppressive” threat, while other common market practices that could equally enable “uncompetitive existing resources, for whom a competitive offer would be significantly higher than zero, to submit offers into the PJM capacity market that do not reflect their actual costs”\(^{93}\) do not. Moreover, as discussed below, the Commission is wrong on the facts that these state climate policies are “uncompetitive” or are not constrained by the discipline of market competition.\(^{94}\)

\(^{90}\) Order at P 153.

\(^{91}\) Id. at P 156.

\(^{92}\) ICC Filing at 17-20. (approximately 145,000 MWs of capacity submitted zero-priced offers, driven by bilateral contracting, retail rate recovery by vertically integrated utilities, intra-company sales, and non-electric product sales).

\(^{93}\) Order at P 153.

\(^{94}\) As discussed above, in contrast to offers motivated by market power, the Commission also does not explain why compensation earned under these programs does not affect a resource’s “actual costs.”
b. The Commission fails to explain its exclusive focus on price suppression to the benefit of supply interests over customers

The Order focuses exclusively on concerns about “out-of-market” payments, which would potentially result in lower bids that tend to lower capacity market clearing prices. But the Commission’s reasoning that such offers are problematic because they do not reflect a resource’s “actual costs” would logically apply equally to offers that are higher than a resource’s “competitive” costs. The Commission’s decision removes from consideration market behavior that is economically equivalent to the actions it targets without explanation. Yet policing the market for offers that are, in the Commission’s view, too low because of differing state regulatory policies while excluding consideration of offers that are too high on the same basis is tantamount to protecting supply interests over customers. This one-sided approach is even more illogical in light of substantial, uncontroverted evidence that low prices are not producing adverse market outcomes. To the contrary, investment is booming, and PJM is awash in capacity above reserve margins. At a minimum, the Commission must offer an explanation for its illogical and skewed approach to market protection. The Federal Power Act compels the Commission to consider the interests of customers in regulating rates.

c. The Commission does not adequately explain its departure from existing precedent, instead mischaracterizing the history of its MOPR decisions.

The Commission states that it has “previously recognized that resources receiving out-of-market support are capable of suppressing market prices, regardless of intent,” citing its 2011 order

95 See infra Section IV.C.
on ISO-NE’s MOPR.\textsuperscript{96} This statement is incomplete and misleading, and it disguises just how radically the Order departs from Commission precedent.

The original purpose of the MOPR was to deter buyer-side market power, i.e., the market power exhibited by entities seeking to lower capacity market prices for the capacity they buy.\textsuperscript{97} To this end, some buyer-side mitigation rules initially contained screens to identify the entities that would have an incentive and ability to manipulate prices downward through buyer-side market power.\textsuperscript{98} In 2011, the Commission approved eliminating two screens that it found to reduce the effectiveness of PJM’s MOPR in mitigating buyer-side market power, the net short test, and the price impact screen.\textsuperscript{99} Contemporaneously, the Commission also broadened ISO-NE’s MOPR, expanding its focus on buyer-side market power to “uneconomic” activity more generally.\textsuperscript{100}

\begin{itemize}
\item \textsuperscript{96} Order at P 288 (citing Order on Paper Hearing and Order on Rehearing, \textit{ISO New England, Inc.}, 135 FERC \textbar 61,029 (Apr. 13, 2011)).
\item \textsuperscript{97} \textit{PJM Interconnection, L.L.C.}, 135 FERC \textbar 61,022 at P 6 (Apr. 12, 2011) (“2011 PJM MOPR Order”) (“The MOPR was established in the 2006 RPM Settlement in order to address the concern that some market participants might have an incentive to depress market clearing prices by offering supply at less than a competitive level.”); \textit{Consol. Edison Co. of New York, Inc.}, 150 FERC \textbar 61,139 at P 46 (Feb. 26, 2015) (the Commission has approved buyer-side mitigation provisions to “deter the exercise of buyer-side market power”); \textit{Midwest Indep. Transmission Sys. Operator, Inc.}, 139 FERC \textbar 61,199 at PP 66-67 (June 11, 2012) (because buyers lack the incentive to exercise market power, there is no need for deterrence and therefore no need for MOPR).
\item \textsuperscript{98} \textit{PJM Interconnection, L.L.C.}, 117 FERC \textbar 61,331 at P 103 (Dec. 22, 2006) (MOPR provisions address “the concern that net buyers might have an incentive to depress market clearing prices”); 2011 PJM MOPR Order at P 6 (describing three screens, including an “incentive screen” in place to identify and deter buyer market power).
\item \textsuperscript{99} See 2011 PJM MOPR Order at PP 86, 101 (eliminating the net-short requirement and price impact screen, respectively); \textit{PJM Interconnection, LLC} 137 FERC \textbar 61,145 at PP 43, 52 (Nov. 17, 2011) (denying rehearing on elimination of the screens).
\end{itemize}
this high-water mark, the Commission asserted that all “[out of market] capacity suppresses prices regardless of intent.”¹⁰¹ Notably, these more expansive MOPR decisions emerged in a historical context in which states were pursuing programs that the Supreme Court would ultimately conclude impermissibly interfered with wholesale market rates.¹⁰²

But even as it adopted broad MOPRs in ISO-NE and PJM to reach resources supported by the state programs of concern,¹⁰³ the Commission nonetheless carved out exceptions to its sweep. In PJM, the Commission pointed to the opportunity for affected entities to request and provide support for mitigation exceptions.¹⁰⁴ The Commission also added wind and solar resources to the list of resources allowed to make zero-price bids into the RPM, observing that “wind and solar resources are a poor choice if a developer's primary purpose is to suppress capacity market prices.”¹⁰⁵ This is because the “capacity value of these resources is only a fraction of the nameplate capacity” due to their “intermittent energy output,” meaning that “wind and solar resources would need to offer as much as eight times the nameplate capacity” of a MOPR-eligible gas resource in order to achieve the same price-suppressive effect.¹⁰⁶ Additionally, developers of renewable energy projects would make decisions based on “several years of auctions and energy market prices” and would necessarily begin construction and incur costs years in advance of the first auction it could participate in. By the time such a resource participates in the capacity auction, “the

¹⁰² See Hughes, 136 S. Ct. 1288.
¹⁰³ 2011 PJM MOPR Order at P 139; ISO-NE, Inc. v. PSEG, 135 FERC ¶ 61,029 at P 165.
¹⁰⁵ 2011 PJM MOPR Order at P 153.
¹⁰⁶ Id.
resource would most likely have tens or hundreds of millions of dollars of sunk costs” resulting in a small or even zero net avoidable incremental cost in any event.\textsuperscript{107}

Throughout the course of issuing and then reeling back its broadest MOPR decisions, FERC hewed to several core principles. First, the Commission consistently recognized that “over-mitigation” in the market was costly, and sought to avoid it across different RTO/ISO contexts.\textsuperscript{108} The Commission concluded, for example, that a MOPR is not needed in the Midcontinent Independent System Operator (“MISO”) market because the load-serving entities who could conceivably exercise buyer market power would have no incentive to do so.\textsuperscript{109} Where the “potential benefits of, and thus incentive to engage in, price suppression are greatly diminished … a MOPR is unnecessary.”\textsuperscript{110} Subsequent FERC decisions adopted a number of adjustments to tailor

\textsuperscript{107} Id. at P 155.
\textsuperscript{108} \textit{PJM Interconnection, L.L.C. PJM Power Providers Grp. v. PJM Interconnection, L.L.C.}, 137 FERC ¶ 61,145 at PP 52-55 (Nov. 17, 2011) (concluding the net-short test was ineffective and unnecessary with addition of unit-specific review).
\textsuperscript{109} The Commission has upheld this determination over protests filed by suppliers who would benefit from application of MOPR to new entrants in 2012, 2015 and most recently again in 2018. \textit{Midwest Indep. Transmission Sys. Operator, Inc.}, 139 FERC ¶ 61,199 at PP 66-67 (June 11, 2012) (vertically integrated utilities own most of capacity but do not have to procure significant capacity in the market, so have little reason to seek to suppress prices); \textit{Midwest Indep. Transmission Sys. Operator, Inc.}, 153 FERC ¶ 61,229 at P 105 (Nov. 20, 2015) (a MOPR is not necessary because even though there is merchant capacity in MISO, “most merchant capacity has been sold under long-term contracts” and “[t]he purchasers of this capacity would not benefit significantly from suppressing prices in the MISO capacity market”); \textit{Midcontinent Indep. Sys. Operator, Inc.}, 162 FERC ¶ 61,176 at P 78 (Feb. 28, 2018) (rejecting, \textit{inter alia}, that low clearing prices in the auction show price suppression by load serving entities rather than market fundamentals).
\textsuperscript{110} \textit{Midwest Indep. Transmission Sys. Operator, Inc.}, 153 FERC ¶ 61,229 at P 106 (Nov. 20, 2015); see also \textit{Con Edison}, 150 FERC ¶ 61,139 at P 45 (Feb. 26, 2015) (finding NYISO’s buyer-side mitigation rules to be “unjust and unreasonable because they are unnecessarily applied to unsubsidized, competitive entrants who have no incentive to inappropriately suppress capacity market prices”).
MOPR’s ambit, exempting renewable resources entirely or those procured in order to meet state renewable policy goals. More recently, the Commission has concluded that existing or proposed expansions of MOPR provisions result in unjust and unreasonable rates absent an exemption, or unit-specific review sufficient to ease the risk of over-mitigation.

Second, well after the 2011 ISO-NE MOPR decision, the Commission continued to view MOPR’s purpose as preventing buyer-side market power. Indeed, as recently as 2016, the Commission represented to the D.C. Circuit that MOPR’s purpose is “to prevent the exercise of monopsony power—that is, price suppression by utilities that offer capacity into the market but buy more capacity than they sell.” Thus within PJM, “[MOPR] is designed to identify new resources with the incentive and ability to depress auction clearing prices.” Only with the recent

\[111\] PJM Interconnection, L.L.C., 143 FERC ¶ 61,090 at P 166 (May 2, 2013) (exempting, inter alia, renewable resources because “MOPR may be focused on those resources that are most likely to raise price suppression concerns.”); New York Pub. Serv. Comm’n, New York Power Auth., & New York State Energy Research & Dev. Auth. v. New York Indep. Sys. Operator, 153 FERC ¶ 61,022 at PP 2, 47 (Oct. 9, 2015) (granting an exemption to buyer-side mitigation rules for certain renewable resources that have “limited or no incentive and ability to exercise buyer-side market power” up to a megawatt cap to be established by NYISO).

\[112\] Brief of Respondent FERC, NRG Power Marketing, LLC v. FERC, Nos. 15-1452, 15-1454, 2016 WL 5405117, at *20, *22 (D.C. Cir. Sept. 27, 2016) (Allowing only categorical exceptions without unit-specific review would fail to “balance[e] the need to mitigate buyer-side market power against the risk of over-mitigating competitive entry”); New York Pub. Serv. Comm’n, 153 FERC ¶ 61,022 at PP 2 (Oct. 9, 2015) (applying MOPR to certain renewables up to a megawatt cap is unjust, unreasonable, or unduly discriminatory or preferential under section 206); Con Edison., 150 FERC ¶ 61,139 at PP 45, 50; cf. PJM Interconnection, L.L.C., 143 FERC ¶ 61,090 at PP 210-212 (May 2, 2013) (declining to expand MOPR mitigation period from one to three years).

\[113\] Brief of Respondent FERC, NRG Power Marketing, LLC v. FERC, Nos. 15-1452, 15-1454 2016 WL 5405117, at *11, *12 (D.C. Cir. Sept. 27, 2016); see also id. at *39-40 (exemptions upheld were designed to sort out resources that lack incentives to bid their actual costs).

\[114\] Id. at *11.
CASPR Order (requests for rehearing of which are still pending) did the Commission abandon the MOPR’s animating purpose of discouraging buyer-side market power in favor of the principle that any state action that undermines “investor confidence” by lowering capacity prices should be subject to mitigation.\textsuperscript{115} Like the CASPR Order, the instant Order represents a dramatic departure from the MOPR’s history and purpose. For the first time in PJM, the Commission remakes the MOPR as a tool to safeguard incumbent generators profit expectations, while abandoning its long-established guiding principle of restricting MOPR so as to chart a course between what the Commission deemed to be under-mitigation and over-mitigation. To pretend otherwise is not just misleading, it is unlawful, as an agency departing from a prior policy must at least “display awareness that it is changing position.”\textsuperscript{116}

In addition to acknowledging its change in position, a “reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy.”\textsuperscript{117} The Commission has failed to offer any such explanation. The Order points to increases in the megawatts of wind and solar resources supported under state RPS programs as evidence that the RPM is under threat, yet it does not explain why the Commission’s prior finding that such resources only have \textit{one-eighth} the price-suppressive potential of similarly situated gas resources no longer applies.\textsuperscript{118} Similarly, the Commission fails to address its prior rationale that “long lead” resources such as renewable projects will have such significant sunk costs before it bids into the

\textsuperscript{115} \textit{ISO New England Inc.}, 162 FERC ¶ 61,205 at P 21 (Mar. 9, 2018) ("CASPR Order").

\textsuperscript{116} \textit{FCC}, 556 U.S. at 515 (emphasis in original).

\textsuperscript{117} \textit{Id.; see also Louisiana Pub. Serv. Comm’n}, 772 F.3d at 1303.

\textsuperscript{118} 2011 PJM MOPR Order at P 153.
capacity market that a reasonable offer is likely to be low or even zero (notwithstanding other factors, such as state support). Instead, the Commission perfunctorily explains its reasoning for expanding the MOPR to existing resources\textsuperscript{119}, without offering a rationale for expanding MOPR to new renewable resources that the Commission had previously recognized would have little ability to suppress prices.

**B. The Commission’s threadbare reasoning contradicts basic economic theory.**

In addition to failing to flesh out key elements of the Commission’s logic, the reasoning in the Order faces another foundational flaw: it contradicts basic economic principles. The crux of the Commission’s reasoning in targeting these state climate policies is that they enable resources to bid below their “true” costs,\textsuperscript{120} produce different outcomes than the “result of competition in the market,”\textsuperscript{121} and threaten the “integrity of competition in the wholesale capacity market.”\textsuperscript{122} In short, the Commission claims that state climate policies make the capacity market less competitive and market prices less reflective of “true” costs. This turns economic theory on its head. It is Economics 101 that policies that address market failures enhance competition, increase efficiency, and result in a more accurate reflection of true costs and benefits in market outcomes.\textsuperscript{123}

\textsuperscript{119} The Commission asserts that “circumstances in PJM have changed,” pointing first to the fact that the existing MOPR would not have applied to nuclear resources benefiting from ZECs whether new or existing and arguing second that while some existing resources have low competitive offers, not all do. Order at P 153. Neither point confronts head on the Commission’s previous logic for excluding renewables, which was based on the particular technical and economic characteristics of renewable resources.

\textsuperscript{120} Order at P 65.

\textsuperscript{121} Id. at P 153.

\textsuperscript{122} Id. at P 150.

“Government action can sometimes improve upon market outcomes. . . . Governments pursue various policies to remedy the inefficiencies caused by externalities.” Economic theory recognizes both the benefits of pricing negative externalities (e.g., carbon tax) as well as valuing positive externalities (e.g., Renewable Energy Certificates or “RECs”). It is undisputed that the policies the Commission targets address the environmental externalities of electricity generation. The uncontroverted evidence in the record also shows that the policies targeted by the Commission do so efficiently, i.e., by securing environmental benefits for a price at or below the independently assessed and externally validated social cost of carbon. When evaluating the policies targeted by the Commission even using a very conservative estimate of the social cost of carbon and

(May 5, 2016) (explaining that failure to price external or public costs created by resources is a form of a subsidy) (cited in Clean Energy Advocates Protest at 53).

124 Mankiw, N. Gregory, Principles of Economics, at 195-96 (Chapter 10 – Externalities) (2011), see also id. at 213 (“Sometimes the government prevents socially inefficient activity by regulating behavior. Other times it internalizes an externality using corrective taxes’’); Flynn, Sean Masaki, Economics for Dummies at 196 (2018) (“negative externalities such as pollution cause overproduction by shifting supply curves’’); Cooper, R. and Andrew, John, Economics – Theory Through Applications, at 522 (2011) (“In the presence of externalities, distortions in the market and some type of government intervention may be warranted. Often, that intervention takes the form of taxes and subsidies that alter individual incentives to encourage behavior that promotes economic efficiency.’’) (emphasis in original); McAfee, Preston and Lewis, Tracy, Introduction to Economic Analysis, at 156 (Chapter 7 – Externalities) (“Externalities create a market failure—that is, a situation where a competitive market does not yield the socially efficient outcome.’’).

125 Mankiw, supra note 124, at 201 (“Positive externalities lead markets to produce a smaller quantity than is socially desirable. To remedy the problem, the government can internalize the externality by taxing goods that have negative externalities and subsidizing goods that have positive externalities.’’); Exelon Protest, Declaration of Robert D. Willig at P 32.

126 IPI Comments at 15, n.47 (“In 2014, the U.S. Government Accountability Office concluded that [the independent body developing the Social Cost of Carbon] had followed a “consensus based” approach, relied on peer-reviewed academic literature, disclosed relevant limitations, and adequately planned to incorporate new information through public comments and updated research.’’); Exelon Protest, Declaration of Robert D. Willig at P 37 n.37.
discounting the significant additional benefits of non-carbon related outcomes (e.g., traditional criterion pollutants, water pollution, etc.), it is clear that they enhance the economic functioning of the market. The Commission cannot base its decision on a contrary finding. “When an agency is statutorily required to adhere to basic economic principles and competition principles . . . the agency must adhere to those principles when deciding individual cases.” The Commission receives no deference for findings so wholly unmoored from basic economic principles.

Nor is it adequate for the Commission to simply disclaim a role in addressing market externalities, when its Order thrusts it into precisely that task. The Commission’s longstanding prior practice has been to defer state judgment de facto by treating different state regulatory regimes as part of the competitive backdrop of resource offers. (e.g., treating emissions permits and fees as part of a resource’s “true” costs). The Commission’s decision diverges from that practice of restraint and places the Commission in the position of supplanting the state’s determination of an externality’s value with its own. Having asserted such a role, the Commission cannot excuse its reliance on a theory that is at odds with basic economics by disavowing its competence over environmental externalities.

See also Mai, et al., “A Prospective Analysis of the Costs, Benefits, and Impacts of U.S. Renewable Portfolio Standards,” NREL (2016) at 33 (assuming existing RPS programs remain in effect until 2050 nationwide, the study found that these programs would lead to estimated costs of $31 billion, compared with environmental and health benefits of $97 billion and global climate benefits of $161 billion)), http://etapublications.lbl.gov/sites/default/files/lbnl-1006962.pdf (cited in Clean Energy Advocates Protest at 19).

Mobil Pipe Line Co., 676 F.3d at 1104.

See supra, note 83.

As we explain in Section D below, the Commission commits a separate error by acting beyond its competency to replace the state’s judgment of the value of the externality with its own.
C. The Commission does not support its finding that PJM’s current rates are unjust and unreasonable with substantial evidence, and fails to respond to relevant data contradicting its theory that state programs harm the capacity market.

The Commission must support the factual findings underpinning its determination with substantial evidence. 131 The Commission must also “respond meaningfully to the arguments raised before it,” 132 and make an “effort to grapple with” alternate theories. 133 It fails to do so, and ignores or fails to reconcile unrebutted record evidence with its flawed legal theory of market harm. The Commission’s factual errors and a failure to “examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made” provide separate grounds for the Commission to reconsider the Order. 134

The Commission bases its determination that PJM’s current rates are unjust and unreasonable upon a finding that “out-of-market payments by certain PJM states have reached a level sufficient to significantly impact the capacity market clearing prices and the integrity of the resulting price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources.” 135 However, the Order fails to provide substantial evidence that the complained of rise in out-of-market payments in fact harms the capacity market’s ability to ensure resource adequacy at just and reasonable rates. Indeed, the Commission never even acknowledges contrary reasoning and evidence showing that policies conveying competitive advantage to select

131 16 U.S.C. § 825l(b); see also S.C. Pub. Serv. Auth., 762 F.3d at 54 (“Substantial evidence is such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.”) (citation and internal quotation marks omitted).
132 Pub. Serv. Comm’n of Ky., 397 F.3d at 1008.
134 National Fuel, 468 F.3d at 839 (quoting Motor Vehicle Mfrs. Ass’n, 463 U.S. at 43 (internal quotation marks omitted)).
135 Order at P 156.
resource types can have minimal or no effect on price and do not interfere with the market’s primary function of securing adequate capacity at a reasonable cost.

Although a cornerstone of the Commission’s reasoning is the distinction between “competitive resources” and resources supported by state climate policy, the Order also fails to respond to relevant evidence in the record demonstrating that the targeted state programs are no different from the myriad policies that have affected each resource’s competitiveness since the inception of organized energy markets. The Commission further ignores real-world data regarding the RPM’s performance that belie the claim that the capacity market is under threat.

Finally, the Commission’s factual findings with respect to the nature and scale of impacts of state RPS programs are unsubstantiated and contradicted by record evidence. The Commission fatally fails to acknowledge that RECs are competitively procured, and never reconciles this fact with its blanket characterization of resources receiving RECs as “uneconomic.”136 In sum, the determination that PJM’s current rates are unjust and unreasonable is arbitrary and capricious because it runs counter to the evidence before the Commission in this proceeding.137

1. The Order does not provide substantial evidence that state programs threaten the integrity of the capacity market.

The Order states that its conclusion that state support of certain resources harms PJM’s capacity market is “compelled by the evidence presented,”138 yet it cites no data to substantiate this theory. Rather, the Order simply takes it for granted that greater participation by state-

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136 Id. at P. 150.
137 See Motor Vehicle Mfrs. Ass’n, 463 U.S. at 43 (“Normally, an agency rule would be arbitrary and capricious if the agency has . . . offered an explanation for its decision that runs counter to the evidence before the agency.”).
138 Order at P 156.
supported resources in the RPM will lead to “unreasonable price distortions and cost shifts” because such resources are “uneconomic,” compromising the “integrity” of the capacity market and creating “uncertainty” among investors.\textsuperscript{139} It leaves key terms such as “uneconomic” and market “integrity” undefined, and points to no record evidence of actual negative impacts on the capacity market’s ability to incent the construction and retention of adequate resources.\textsuperscript{140}

The absence of data linking state actions to market effects is particularly telling. PJM, which has access to all the data on offers and pricing outcomes from the past 14 auctions, could not provide a single example of a state policy resulting in price suppression, though state RPS programs have been in place throughout that period.\textsuperscript{141} If RECs affected the market’s ability to procure adequate capacity, PJM would have data to show it. The Order’s bare assertions that state support for renewable and nuclear resources threatens PJM’s capacity market do not rise to the level of substantial evidence.\textsuperscript{142}

2. The Order fails to address relevant data contradicting its theory of market harm.

The Order fails to address evidence presented by Clean Energy Advocates and other parties contradicting the Commission’s favored theory that state programs supporting renewable and nuclear resources threaten PJM’s capacity market.

First, the Commission never acknowledges or grapples with challenges to its chosen rationale that (i) state climate policies suppress prices and (ii) do so to a degree that threatens the

\textsuperscript{139} Order at P 150.
\textsuperscript{140} Columbia Gas Transmission Corp., 628 F.2d at 592 (when FERC “finds it necessary to make predictions or extrapolations from the record, it must fully explain the assumptions it relied on to resolve unknowns and the public policies behind those assumptions.”).
\textsuperscript{141} ICC Filing at 14.
\textsuperscript{142} See Algonquin Gas Transmission Co., 948 F.2d at 1313 (“An agency’s unsupported assertion does not amount to substantial evidence.”).
market’s objective. Each of these critical steps in the Commission’s logic is undercut by arguments and evidence in the record. The Institute for Policy Integrity described three separate grounds by which the targeted state climate policies could result in little to no change in the market clearing price, or could even produce *price increases* rather than “price suppression.” First, renewables participate in the capacity market to a limited degree due to market barriers not at issue in this proceeding.\(^{143}\) Second, such resources that do participate in the capacity market affect price only under limited circumstances (where the resource is marginal or would not have entered the market but for the state support).\(^{144}\) Third, because of decreased energy revenues due to competition from renewables, state climate policies may result in *higher* capacity market bids from conventional generators that are more frequently the marginal resource, pushing capacity market prices upward.\(^{145}\) The Commission simply did not address this contrary reasoning in the Order.

Similarly, the Commission offers no response to reasoning and evidence presented by several commenters that PJM’s capacity market readily absorbs resources supported by state climate policies without significant impact. These commenters point out that the “simplified market analysis” offered by PJM to show that the addition of a certain quantity of zero-priced resources results in lower prices—the only analysis of any kind cited in the Order—is not an accurate prediction of how markets are actually affected by state climate policies.\(^{146}\) It fails to

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\(^{143}\) IPI Comments at 29; *see also* Clean Energy Advocates Protest at 58-59.

\(^{144}\) IPI Comments at 29-30.

\(^{145}\) *Id.* at 30.

\(^{146}\) Clean Energy Advocates Protest at 109; IPI Comment at 29; Protest of the New Jersey Board of Public Utilities at 19-20 (May 7, 2018); ICC Filing at 15-16; Protest of the Office of the People’s Counsel for the District of Columbia, Maryland Office of People’s Counsel, and New Jersey Division of People’s Counsel, Docket ER18-1314 at 3 (May 7, 2018) (hereinafter “People’s Counsel Protest”).
account for market dynamics such as entry and exit and market participants’ responses to the entry and exit decisions of other market actors, including the ability of short lead time resources (e.g., imports, demand-response) to buffer prices. As economist James Wilson explained, state policies are in most cases “known well in advance of the RPM auctions in which they first participate.”

Accordingly, “it is reasonable to assume that the incremental resources are reflected in market participants’ various entry and exit decisions, and do not affect price appreciably.”

Even when a resource is not fully anticipated by the market, “after a few delivery years it should again be the case that the market has adjusted to and absorbed the additional capacity, with RPM prices again finding the point that balances supply and demand, entry and exit.”

Second, the Order ignores objective indicators of market performance and design features of the capacity market that belie the claim that it is under threat, as raised in multiple protests and comments to PJM’s filing. PJM’s latest planning reserve margin for the summer of 2018 is 28.7 percent, significantly higher than PJM Staff’s recommended installed reserve margin target of

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148 Id.
149 Id. at P 25.
150 Clean Energy Advocates Protest at 35-40; see also Protest of Joint Consumer Advocates, Docket ER18-1314 at 11-13 (May 7, 2018) (“PJM has the most drastic capacity oversupply of any RTO in North America.”) (hereinafter “Consumer Advocates Protest”); People’s Counsel Protest at 2-4; Protest of the Clean Energy Industry Associations, Docket ER18-1314 at 11 (May 7, 2018) (noting that “PJM has said that its system is ‘safe and reliable today—it has been designed and is operated to meet all applicable reliability standards’”) (citing Comments and Responses of PJM Interconnection, L.L.C., Docket No. AD18-7-000, at 4 (March 9, 2018)).
between 15.8 and 16.1 for delivery years 2018/2019 through 2021/2022.\textsuperscript{152} Over 20 GW of new natural gas capacity is under construction or in advanced development and is expected to enter operation by the end of 2021; an additional 18 GW of natural gas capacity has been announced or is in early development.\textsuperscript{153} At the same time, only 7.4 GW of fossil and nuclear capacity have announced and approved retirement dates between now and 2021.\textsuperscript{154} By 2021, PJM could see a net addition of up to 40 GW, even as load is expected to see relatively little growth over the same timeframe.\textsuperscript{155} Moreover, there is no evidence at all to suggest the investor appetite in the PJM region is on the wane. A recent, informal poll at the Platt Global Power Markets Conference found that a large plurality (45 percent) of respondents “think that PJM is the best place where investors are likely to earn a targeted rate of return on new generation.”\textsuperscript{156} As PJM itself stated in the Resource Investment Whitepaper cited in its filing, “[g]iven the level of capital being attracted to

\textsuperscript{152} PJM, 2017 PJM Reserve Requirement Study at 21 (Oct. 12, 2017), \url{http://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx}; see also Consumer Advocates Protest at 12 (noting that “the North American Electric Reliability Corporation’s 2017 Summer Reliability Assessment demonstrated [that] PJM’s 28-percent anticipated reserve margin exceeds its reserve requirement of 16.6 percent by approximately two-thirds”); IPI Comments at 28-35.


\textsuperscript{154} \textit{Id.}

\textsuperscript{155} \textit{Id.}; see also Consumer Advocates Protest at 13 (noting that “load has flattened” in PJM and that this trend is “expected to continue”); People’s Counsel Protest, Affidavit of James F. Wilson at P 19 (“Resource adequacy in PJM is in good shape. This is largely due to flat loads, moderate natural gas prices, and declining costs for natural gas and renewable resources. . . . These circumstances are not expected to end anytime soon.”).

\textsuperscript{156} Watson, \textit{supra} note 151.
PJM, it seems highly implausible to claim the market is not compensating merchant investors enough for risks they assume.”\textsuperscript{157}

Nor would a resource adequacy problem be expected according to the economic theory underlying the capacity market—economic theory that is completely ignored by the Order. As Clean Energy Advocates explained, by design, “the capacity market would react” to the economic effects of state programs.\textsuperscript{158} The presence of state-sponsored capacity would not prevent the future entry of non-subsidized resources to the extent such resources are necessary. PJM’s capacity market demand curve provides that “any decrease in price” that might theoretically be caused by lower offers that reflect state program revenue “can continue only as long as there is a glut in capacity.”\textsuperscript{159} If supplies ever dip, the market will respond by producing higher prices, sending a signal to market actors to provide adequate supply.\textsuperscript{160} This basic market function will continue to operate even if, hypothetically, large percentages of the capacity resources in the market were to receive state support.

Third, the Order does not respond to historical data presented by Clean Energy Advocates and others, which demonstrate that government policies have long provided substantial support targeted toward specific types of capacity resources, including large-scale ones that comprise a significant share of capacity in the PJM market. There is no reason to believe that historic policy

\begin{footnotes}
\item[159] \textit{Id.} at 18.
\item[160] \textit{Id.}
\end{footnotes}
actions would have any less impact on market prices than the Commission contends they do today.\textsuperscript{161} As Commissioner Glick points out in his dissent, federal government intervention has reduced the costs of domestic fossil fuel supply since 1916, and provided close to a trillion dollars in energy subsidies since just 1950 – the vast majority to fossil fuel technologies.\textsuperscript{162} In 1989 alone, for example, coal-fired generators benefited from nearly seven and a half billion dollars in federal government support, and natural gas fired generators a little less than one billion dollars.\textsuperscript{163} On average in that year, federal subsidies to conventional generation amounted to roughly eleven percent of the cost of electricity to an end-consumer.\textsuperscript{164} It defies reason to suggest that support of this magnitude did not affect the composition of capacity resources, providing advantages to some resources and not others, and affecting wholesale prices.\textsuperscript{165} Indeed, subsidy expert Doug Koplow concludes that historic subsidies that have underwritten long-lived capital investments would have “the same type of market effect as current subsidies.”\textsuperscript{166} The same basic principle would apply,

\begin{itemize}
\item\textsuperscript{161} See Comment of Harvard Electricity Law Initiative, Docket ER18-1314 at 3 (May 7, 2018) (hereinafter “HELI Comment”) (noting that “state generation procurement policies have long co-existed with restructuring and pre-date PJM’s capacity construct by nearly a decade”); Order (Glick, R. dissenting at 7) (government interventions not addressed by the majority’s decision “have had a far greater ‘suppressive’ impact on the markets than the ‘actionable subsidies’ targeted by today’s order”).
\item\textsuperscript{162} Order (Glick, R. dissenting at 7).
\item\textsuperscript{164} Id. at 20.
\item\textsuperscript{165} Order (Glick, R. dissenting at 7) (“By lowering the marginal cost of fossil fuel-fired units, government policies have allowed these units to operate more frequently and have encouraged the development of more of these units than might otherwise have been built.”).
\item\textsuperscript{166} Doug Koplow, Earth Track, Inc., Energy Subsidies within PJM: A Review of Key Issues in Light of Capacity Repricing and MOPR-Ex Proposals, Prepared for Sierra Club at 3 (May 7, 2018) (attached to Clean Energy Advocates Protest) (hereinafter “PJM Subsidies Study”); see also HELI Comment at 13 (“PJM does not provide any empirical evidence demonstrating that the
“regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted.”

Uncontroverted evidence in the record shows incumbent generators have received many large state tax breaks that are documented as far back as the 1950s, 1960s, and 1970s. Federal and state interventions beyond ZEC and RPS programs that advantage particular energy technologies persist today. For example, Commissioner Glick observed that PJM states have adopted over 100 programs to support particular resources, including actions providing 100 million to a billion dollars of incentives a year to support the coal industry or natural gas development.

Fourth, the Order provides no basis for its differential treatment of a state’s “out-of-market” support for an existing nuclear power plant and the practice of rate-basing unprofitable coal-fired power plants. As detailed by Clean Energy Advocates, FirstEnergy successfully pursued this strategy with the transfer of the 1,984 MW coal-fired Harrison Station, previously a merchant generator, from a FirstEnergy subsidiary to another West Virginia-regulated subsidiary, forcing retail customers to pick up the tab for an estimated $160 million in losses over a three-year period. The transfer likely forestalled Harrison’s retirement, as demonstrated by the proposed retirement of a similarly-situated plant, Pleasants Power Station, when it was denied the terms of a similar transfer. Under the Commission’s theory of market harm, a coal plant kept afloat by

policies it targets have greater effects on wholesale rates than the utility business models that it exempts.”

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167 PJM Subsidies Study at 6.
168 Id. at 19.
169 Order (Glick, R. dissenting at 8).
170 Clean Energy Advocates Protest at 84-85.
171 Clean Energy Advocates Protest at 85.
out-of-market retail customer support would appear to have the same sort of suppressive effect on capacity prices as an existing nuclear plant receiving state support via ZECs, yet the Order provides no explanation for painting one as a threat to the RPM but not the other.\textsuperscript{172} Moreover, as Commissioner Glick points out, vertically integrated utilities guaranteed to recover their costs regardless of market price are “one of the largest sources of out-of-market support.”\textsuperscript{173} Even the original Complainants in the Calpine docket recognized that guaranteed cost recovery created the same incentives and market behavior as the later-challenged ZECs.\textsuperscript{174} Targeting resources the Commission has long recognized are a poor means to cause price suppression (i.e., renewables) while ignoring one of the largest categories of potentially price-suppressive “out-of-market support” is nonsensical.

In sum, the Commission does not even attempt to reconcile its claim that the effect of state policy on markets is greater than ever with contradictory data. This data indicates that the participation of state-supported renewables in the RPM has little effect on capacity prices or the capacity market’s ability to guarantee adequate resources, both because of the distinctive qualities of renewable resources and the demonstrated resilience of the RPM. This data also indicates that many government policies affect capacity prices, not just those state programs singled out in the

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\footnote{\textsuperscript{172} See Order (Glick, R. dissenting at 9) (explaining that there is “no reason to isolate a few disfavored state policies for mitigation and claim, without any support, that they are the only subsidies that threaten the integrity of the market”).}
\footnote{\textsuperscript{173} Id. at 8 (citing ICC Filing at 19; HELI Comment at 8).}
\footnote{\textsuperscript{174} Complainants compared the generous term of the proposed power purchase agreements to “traditional cost-of-service, rate-of-return regulation” that distorts incentives. Calpine Complaint at 26, Cavicchi Aff. at P 46 (“The guaranteed recovery of all costs including a return on equity will create incentives for AEP Genco and FES to sustain inefficient operations (i.e., operations and investment that would not be economic under PJM’s market-determined prices).”).}
\end{footnotes}
Order, as does out-of-market support for existing coal resources through rate-basing. This unrebuted evidence reveals central flaws in the Order’s reasoning. The Commission’s failure to address this evidence falls short of the Commission’s obligation to “respond meaningfully to the arguments raised before it.”

3. The Commission fails to grapple with evidence contradicting claims that RPS programs are “uneconomic.”

The Order claims that “there is an important difference between a resource that offers low as a result of competition in the market and one that offers low because a state subsidy gives it the luxury of doing so.” Yet the Commission fails to address record evidence that RPS are in fact competitive programs. As noted by PJM’s Independent Market Monitor, “RPS programs are generally competitive.” Commissioner LaFleur echoes this point in her dissenting option. Competition for RECs drives their price down and brings the same incentive to innovate as other forms of competition. Thus, precise revenues from RECs are not guaranteed to all eligible renewable resources under a state program. Additionally, where eligible resources secure long-term power purchase agreements pursuant to state programs, these are often the result of winning competitive solicitations.

175 Pub. Serv. Comm’n of Ky., 397 F.3d at 1008.
176 Order at P 153.
177 Answer and Motion For Leave to Answer of the Independent Market Monitor for PJM, Docket ER18-1314 at 6 (May 25, 2018).
178 Order (LaFleur, C. dissenting at 2) (distinguishing RPS programs, which “help shape a state’s resource mix over time through competitive procurements,” from other state support programs).
179 Clean Energy Advocates Protest at 119. As noted by Clean Energy Advocates, state policies designed to encourage energy storage resources, not clearly targeted by PJM, can similarly be designed to encourage competition. See Energy Storage Association, State Policies to Fully Charge Advanced Energy Storage: The Menu of Options at 4 (July 2017) (setting forth a
As PJM acknowledged in its Resource Investment Whitepaper, competitive procurements “do[] not present the same threat” it sees in administratively determined support.\textsuperscript{180} Further, PJM expert Dr. Giacomoni conceded that “not all” RPS resources depend on state support to be economic, noting that some existing sources “may have avoidable costs that are low enough to be met with other PJM market revenues.”\textsuperscript{181} There is not substantial evidence in the Order for concluding that RPS programs or the resources they procure are uncompetitive and uneconomic, and the Commission fails to respond to evidence that such programs actually harness competitive forces to achieve efficient outcomes.

4. The Commission in particular lacks evidence of the magnitude of RPS programs’ impact on the capacity market.

In addition to its flawed theory of market harm, the Commission grounds the Order on a conclusion that data presented by PJM demonstrates that “increasing out-of-market support” from RPS programs “will significantly affect the PJM capacity market.”\textsuperscript{182} However, the Commission does not interpret its asserted evidence of the magnitude of RPS influence in the capacity market correctly, relying instead on the unsupported insinuation that what is true of ZEC resources is true of other state-supported resources. Indeed, the record is entirely devoid of a demonstration that RPS programs affect capacity market prices. Because the Commission relies on a factual record

\textsuperscript{180} PJM Resource Investment Whitepaper at 45.
\textsuperscript{181} PJM filing, Affidavit of Dr. Anthony Giacomoni at P 30.
\textsuperscript{182} Order at P 152.

menu of competitive energy storage policy options),
of the growing threat of increasing out-of-market support as a key basis for its Order, inaccuracies in the claimed record provide separate grounds upon which the Order must be reversed.\textsuperscript{183} Here, as in \textit{National Fuel}, the Commission is “[p]rofessing that an order ameliorates a real industry problem but then cit[es] no evidence demonstrating that there is in fact an industry problem.”\textsuperscript{184}

In the PJM expert affidavits relied upon in the Order, the only analysis of the price-suppressive potential of actual resources pertains to existing nuclear power plants.\textsuperscript{185} When it comes to RPS programs, the Commission, like PJM, simply cites the megawatt targets of the programs and assumes that price-suppression will result.\textsuperscript{186} But greater ambition of state RPS targets does not automatically result in greater participation by state-supported resources in PJM’s capacity market. Many states have spending caps for their RPS programs, and many programs allow for REC purchase obligations to be satisfied with RECs from outside of PJM’s service territory.\textsuperscript{187} Moreover, load serving entities may often satisfy their REC purchase obligations by paying penalties or alternative compliance payments to the state.\textsuperscript{188} Finally, many resources receiving payments for RECs may choose not to participate in the capacity market. Without addressing these issues, the Commission cannot meaningfully estimate how state RPS programs affect the RPM.\textsuperscript{189} In sum, despite its assertion to the contrary, the Order fails to provide evidence

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\item \textsuperscript{183} \textit{National Fuel.}, 468 F.3d at 839 (emphasis in original).
\item \textsuperscript{184} \textit{Id.} at 843.
\item \textsuperscript{185} PJM Filing, Affidavit of Adam J. Keech at PP 10-12.
\item \textsuperscript{186} Order at P 152.
\item \textsuperscript{187} Clean Energy Advocates Protest at 14.
\item \textsuperscript{188} \textit{Id.} at 15.
\item \textsuperscript{189} As explained above, the Order’s assertion that total “out-of-market” support for generation is increasing also misinterprets the data because it ignores record evidence submitted by Clean Energy Advocates and others demonstrating that similar programs of greater magnitude have impacted the capacity market since its inception.
\end{enumerate}
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that RPS programs are impacting the capacity market and will do so with increasing magnitude in the future.

**D. The Commission’s finding that state implementation of climate policies renders wholesale markets unjust and unreasonable usurps the states’ rightful role under the Federal Power Act.**

The Commission’s broad decision exceeds its proper role under the Federal Power Act by intentionally frustrating state climate regulations and forcing a skewed playing field on market participants where products compensating emissions avoidance and other environmental benefits have no value, even when state property law says they do. As Commissioner Glick states in his dissent, “nothing in the FPA, [the Commission’s] regulations, or the many court cases interpreting both . . . requires [the Commission] to use [its] authority to stymie state efforts to fight climate change in this manner.” To the contrary, the Federal Power Act explicitly reserves the authority of states to act as environmental regulators of generation. Without a statutory basis for its decision to value environmental credits at zero in calculating capacity market offers, the Commission’s decision to do so renders rates unjust and unreasonable and unduly discriminates against resources that earn revenue from selling such credits.

**1. The Commission’s Order usurps states’ role under the Federal Power Act.**

Under the Federal Power Act, the Commission does not set its own environmental policies. Rather, the Federal Power Act allows the Commission to recognize the actions of environmental regulators and to provide for the efficient administration of markets when accounting for their policies. For some policies, such as the Regional Greenhouse Gas Initiative ("RGGI"), that happens naturally, with no further intervention from the Commission. RGGI requires generators to purchase and retire allowances in order to emit greenhouse gases. The cost of purchasing

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190 Order (Glick, R. dissenting at 12).
allowances is reflected in emitting units’ offer prices, which influence the capacity clearing price and the chosen mix of resources. For other policies, affirmative regulatory action by the Commission may be necessary to enhance market efficiency. For example, the Commission issued an order to ensure that resources whose run time is limited by state environmental regulation are able to submit market offers that reflect the opportunity costs of operating during any given hour (giving up the opportunity to operate during other hours). But the Commission’s action in this case runs completely contrary to this precedent. Rather than facilitating efficient market operation given the choices of other regulators, the Order frustrates the decisions of state environmental regulators by undoing their economic consequences.

That was not what was envisioned when grid operators created capacity markets and the Commission approved them. As the D.C. Circuit explained in upholding the Commission’s authority to create capacity markets, the markets were designed to take state regulation of generation mix as an input. Rather than forcing a particular generation mix on states, capacity markets were designed merely to ensure a reserve margin is hit so as to reduce the likelihood of future blackouts:

191 As PJM explains, where a state regulation limits a unit’s run time, that creates an opportunity cost because operation in any given hour may entail “giving up revenue that it could earn if it was running at a more profitable time of the year.” PJM, A Review of Generation Compensation and Cost Elements in the PJM Markets at 15 (2009), https://perma.cc/BMV7-5QNL. Faulting PJM for not “clearly and explicitly provid[ing] for the inclusion of opportunity costs, especially for energy and environmentally-limited resources” (resources whose run time is limited by state or federal environmental regulations) in resources’ default bids, the Commission ordered PJM to revise its mitigation rules to do so. PJM Interconnection, L.L.C., 126 FERC ¶ 61,145 at P 42 (Feb. 19, 2009).

192 See Clean Energy Advocates Protest at 52-57 (detailing how erroneously treating the effects of state policies as market failures would frustrate state policy objectives).
The “Installed Capacity Requirement” is misnamed because increasing it doesn’t actually “require” anyone to “install” any new “capacity” at all. State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission. Of course, those choices affect the pool of bidders in the Forward Market, which in turn affects the market clearing price for capacity.  

By taking the extraordinary step of upending this market organization, the Commission replaces the environmental regulatory choices of state regulators to address climate change and replaces them with its own decision to ignore the costs of pollution and the benefits of avoiding it. This infringes on the states’ explicitly reserved authority to regulate generation under the Federal Power Act. As Commissioner Glick explains, “[i]t is not the Commission’s role under the FPA to create an electricity market free from governmental programs aimed at public policy considerations.” Rather, “[t]he FPA is clear that the states, not the Commission, are the entities responsible for shaping the generation mix.”

While the Commission asserts that states can still accomplish their goals by requiring their customers to pay more than necessary to support a reliable system, that assertion is incorrect from a factual perspective and, even if true, ignores the fact that imposing unnecessary capacity costs

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193 Connecticut Dep’t of Pub. Util. Control, 569 F.3d at 481.
194 Order (Glick, R. dissenting at 5).
195 Id. (Glick, R. dissenting at 2).
196 State policies aim to replace polluting resources in the generation mix with clean ones. The Commission is essentially saying that states may still support clean resources, but the Commission will merely insist that they continue to buy extra, unnecessary polluting resources as a consequence of doing so. Such a mandate frustrates the fundamental purpose of the state policy. This mandate taxes states for the right to pursue their environmental goals (through added capacity costs) and may prevent achievement of the goals by keeping highly emitting generators online (thereby potentially providing for continued emission of pollution that states aim to avoid). See Clean Energy Advocates Protest at 52; see also Order (Glick, R. dissenting at 5).
on customers violates the Commission’s duty to ensure just and reasonable rates. The Commission’s allusion to its previous mitigation of natural gas generators supported by Maryland and New Jersey programs is unpersuasive. That action, upheld by the Third Circuit, dealt with a case in which states directly adjusted PJM capacity prices rather than valuing separate non-FERC jurisdictional products to compensate resources for their environmental benefits.  

A federal court ruling upholding the Commission’s authority to override the states’ attempts to modify the PJM capacity price does not grant the Commission’s authority to overturn environmental regulations in this case.

2. In ignoring valid property rights under state law, the Commission unduly discriminates against resources that earn revenue from RECs and ZECs.

While the full scope of the Commission’s Order is vague, it is clear that the Commission intends to force resources to make capacity market offers that ignore revenue they earn for selling RECs and ZECs. But such credits are valid state property rights, just like other costs and revenues that resources pay and earn, which affect their capacity market offers. As Commissioner Glick notes, “the Commission’s proposal would effectively force state-sponsored resources out of

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197 See Order (Glick, R. dissenting at 5 n.11) (explaining how prior “cases do not address the situation in which the Commission is targeting state efforts to regulate the consequences of electricity generation that fall within the states’ statutory authority and that are not addressed in the markets subject to Commission jurisdiction”).

198 As the Commission acknowledges, RECs and ZECs are “not payments for, or otherwise bundled with, sales of energy or capacity at wholesale.” Brief for the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance at 10, Vill. of Old Mill Creek v. Star, Nos. 17-2433 and 17-2445 (consolidated) (7th Cir. May 29, 2018); see also WSPP Inc., 139 FERC ¶ 61,061 at PP 18-26 (Apr. 20, 2012) (holding that the Commission does not have jurisdiction over unbundled RECs).

199 See Wheelabrator Lisbon, Inc. v. Conn. Dep’t of Pub. Util. Control, 531 F.3d 183, 186 (2d Cir. 2008) (“RECs are inventions of state property law.”); Clean Energy Advocates Protest at 10-12 (explaining the basic structure of RECs).
the capacity market, depriving them of a payment for capacity that they will actually provide and leaving it to the states to pick up that tab.”

In forcing such resources to sell their capacity in a separate market (if the Commission’s barely-conceived resource-specific fixed resource requirement proposal ever becomes a reality), the Commission unduly discriminates against them. Resources that earn revenue pursuant to state programs will not be permitted to include all of their costs and revenues in RPM offers, while other resources are able to do so. The Commission does not explain why the property rights it targets (REC and ZEC) are different from other property rights and should be ignored. Conversely, the Commission discriminates in favor of chosen resources (those that do not earn revenue through sales of products that compensate for environmental benefits). Many such resources receive support from sources other than those identified by the Commission’s order (such as through federal policies that reduce the price of natural gas). But the Commission, without explanation, nevertheless deems these other resources “competitive” and fails to offer any rational reasons why the market should discriminate between resources that receive state support and those do not. To the contrary and as explained above, allowing offer prices to reflect a resource’s costs, as determined by state and federal property laws is supported by the Commission’s statutory standards.

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200 Order (Glick, R. dissenting at 2).
201 Id. (Glick, R. dissenting at 5) (“Make no mistake, although the Commission frames today’s order in terms of the effect of certain state-sponsored resources on wholesale rates, the order’s rationale is clear that the Commission’s real aim is to support certain resources that do not benefit from state efforts to address environmental externalities.”).
202 See Clean Energy Advocates Protest at 88-90 (detailing material out-of-market support to conventional generators).
At a time when climate change urgently threatens our nation, the Commission has done one step worse than closing its eyes to the problem: it is affirmatively frustrating other regulators’ attempts to address the threat. The Commission does not have the authority to stymie climate change regulation in this manner, and its decision to do so renders rates unjust, unreasonable, and unduly discriminatory.

E. The Commission should reconsider or, alternatively, clarify its overly broad assertion that resources supported by state policies are not similarly situated to so-called “competitive” resources.

We do not seek reversal of the Commission’s legal finding that PJM’s proposals are not just and reasonable. For reasons described above, FERC lacks a clear rationale for treating resources supported by state climate policies differently. But while we disagree with many aspects of the Commission’s reasoning underlying its rejection of PJM’s proposals, we focus here on one narrow aspect of that decision because it is written so broadly as to inadvertently implicate matters far beyond those addressed in this proceeding.

Paragraph 68 of the Order states that “[t]he receipt of out-of-market support is a difference that requires different ratemaking treatment when such support has a material effect on price or cannot otherwise be justified by our statutory standards.” The statement inadvertently suggests that perhaps state-sponsored resources must be treated differently in all markets (including energy and ancillary services). Such a conclusion runs contrary to the long history of providing equal treatment to state-supported resources in these markets. Such a sweeping determination also cannot be supported by the factual record, given this proceeding’s narrow focus on the circumstances in the PJM capacity market. The Commission should reverse or narrow this finding.

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203 Order at P 68 (emphasis added).
V. Conclusion

For the foregoing reasons, Clean Energy Advocates request rehearing and a reversal of the Commission’s determination under Federal Power Act section 206 that PJM’s existing tariff renders capacity market rates unjust, unreasonable, or unduly discriminatory. Clean Energy Advocates also request the Commission reverse or narrow the findings of paragraph 68 of the Order.

In the alternative, if the Commission will not reverse its section 206 finding, Clean Energy Advocates request the Commission convert the determination into a preliminary finding combined with a show cause proceeding. It appears likely that parties may not even have a detailed proposal to comment on before the Commission announces final changes to PJM capacity market, and the compressed time frame of the announced paper hearing is simply insufficient for commenters to address complex, essential questions of how a just and reasonable replacement rate might function. In its rush to overhaul the RPM’s rules in time for next year’s capacity auction, Commission has overlooked Administrative Procedure Act requirement that it provide interested parties meaningful notice and opportunity for comment on the proposed changes. Instead, the Commission should institute a show cause proceeding, which would provide a forum for the further deliberation that is clearly needed before reaching a well-supported determination regarding the threats, if any, posed to PJM’s capacity market. The additional time for deliberation

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204 See Order, (LaFleur, C. dissenting at 4) (“This is too important a decision to be made this quickly, and with this little stakeholder engagement.”).
205 See 5 U.S.C. § 554 (requiring parties to be notified of “the matters of fact and law asserted”); Cleveland Bd. of Educ. v. Loudermill, 470 U.S. 532, 546 (1985) (“[t]he essential requirements of due process . . . are notice and an opportunity to respond”); Mathews v. Eldridge, 424 U.S. 319, 333 (1976) (the opportunity to be heard must be “at a meaningful time and in a meaningful manner”).
would also avert the impending chaos and uncertainty triggered by the Commission’s Order to re-design core aspects of PJM’s capacity market rules within 60 days.

Respectfully submitted,

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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.


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Exhibit D
Comments of Clean Energy Advocates Separately Addressing the Scope of the Expanded Minimum Offer Pricing Rule, October 2, 2018
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, et al.

Docket Nos. ER18-1314-000
ER18-1314-001
ER18-1314-002

v.

PJM Interconnection, L.L.C.

Docket Nos.

EL16-49-000
EL16-49-001
EL18-178-000
EL18-178-001

COMMENTS OF CLEAN ENERGY ADVOCATES SEPARATELY ADDRESSING THE SCOPE OF THE EXPANDED MINIMUM OFFER PRICING RULE

Pursuant to Rule 212 of the Federal Energy Regulatory Commission ("Commission" or "FERC") Rules of Practice and Procedure,1 Natural Resources Defense Council, Sierra Club, and Sustainable FERC Project (collectively, "Clean Energy Advocates") hereby respond to request for comments on a proposed replacement rate in its Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act, Docket Nos. EL16-49-000, et al. (June 29, 2018) ("PJM Capacity Market Order" or "Order"), which rejected the PJM Interconnection, L.L.C. ("PJM") proposed tariff revisions as not just and reasonable, held that existing capacity market tariff provisions are not just and reasonable, and instituted further proceedings to determine a replacement capacity market rate. Clean Energy Advocates address in this filing only the portions of the Order pertaining to the scope of the minimum offer pricing rule ("MOPR") to apply to the capacity market going forward. Clean Energy Advocates also join two separate comments that address the terms of a resource-specific

fixed resource requirement alternative, the first providing shared principles for the alternative and the second offering a specific, more detailed proposal. The substance of those separate comments is not repeated here.

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SUMMARY OF ARGUMENT

The Commission’s Order heralds sweeping, unwarranted changes to the PJM capacity market rules, and gives the Commission in the impossible task of policing any state policy that affords a competitive advantage to a resource that may threaten “market integrity.” Clean Energy Advocates opposed the Commission’s sharp departure from its own precedent, and maintain objections to the Order in a still-pending request for rehearing. Subject to and without waiving those fundamental objections to the Commission’s Order, Clean Energy Advocates offer comments in response to the Commission’s request for input on the scope of an expanded MOPR. In the spirit of constructive engagement, we take as our starting point for these comments the stated goal of the Commission’s Order (though we disagree with its underlying premise) to identify a just and reasonable means of addressing the market effects of out-of-market payments.

First and foremost, the Commission must not forget the lessons of its past forays into MOPR expansion. Over the years, the Commission has consistently recognized that MOPR does not result in just and reasonable rate where it leads to over-mitigation. An overly inclusive MOPR undercuts the benefits of competition in the markets, and entails hefty administrative costs. The answer cannot be simply to apply a MOPR to any resource remotely suspected of receiving out-of-market revenue. Doing so would impose significant costs on customers.

Instead, the Commission should focus on its stated aim and target only government actions that have a high probability of actually affecting market outcomes. First, a government incentive must be certain enough and significant enough to affect resource bidding behavior and, second, the incentive must be large enough and impact enough capacity to have some probability of affecting market clearing prices. Exceptions to MOPR (whether applied through an express exemption or implicitly by adopting a limiting definition of support that is “actionable”) should
not depend on distinctions that are not related to an incentive’s market effects. Exceptions should apply to incentives that are not certain or not likely to be significant enough to affect a resource’s bid; and to those that are small in an absolute sense or impact small quantities of capacity, such that the incentives are unlikely to significantly affect market outcomes. A right-sized MOPR nets the big fish and lets the little fish go. The Commission should also refrain from applying the MOPR to programs that enhance market efficiency by correcting for well-understood market externalities, as well as programs that rely on market competition. Programs that rely on competition ensure a resource faces the risks and corresponding incentives of competition, and therefore do not pose the same potential for market effects as other government programs.

Measured against the aims set by the Commission’s Order, PJM’s latest proposal is a failure.¹ PJM proposes to exempt the largest, most extensive source of out-of-market revenue, retail cost-recovery. This single category of government action has the potential to shape the competitiveness of 25 percent of the capacity in PJM, and cost-recovery can be substantial enough in magnitude to keep uneconomic resources from retiring and spur uneconomic entry. In addition, PJM proposes to use a “material subsidy” standard that would consider a small payment to a 21MW resource “material” (because it surpassed one percent of the resource’s expected market revenue) while ignoring a payment that is 50 times greater in absolute magnitude to a 1000 MW resource as “immaterial” (because the payment is just below one percent of the larger resource’s expected market revenue) – even if the latter incentive affected half the generation in a state. In essence, PJM’s proposal chases the minnows and lets the big one get away.

¹ Based on the last information presented to stakeholders at the PJM Markets & Reliability Committee’s September 11th meeting.
Clean Energy Advocates propose the following as guidelines for the Commission’s determination of the scope of an expanded MOPR, each based upon the motivating principle of addressing market effects of out-of-market government support. Each of these proposals is described and further supported herein.

- The definition of “actionable subsidies” must not arbitrarily exclude some forms of government support (e.g., incentives that reduce fuel cost).
- Exceptions should apply to government support that is not certain or significant enough to impact bidding behavior.
- Exceptions should apply to government support that is small on an absolute scale or affects a small amount of capacity, because such support is unlikely to affect market outcomes.
- A 20MW size threshold for MOPR applicability is appropriate.
- Valuation of market externalities that are objectively defined, well-documented, and recognized in mainstream economic theory should not be treated as anti-competitive out-of-market payments.
- State RPS programs should be exempted because they are unlikely to materially affect market outcomes:
  - these programs do not typically provide a guaranteed stream of revenue that reliably affects bidding behavior;
  - the size and scope of the support remains insignificant relative to the scale of the market;
  - and the administrative burden of administering MOPR to these programs is large.
- Absent an exception for RPS programs as a whole, RECs that are purchased in competitive markets or procurements should be excluded, because such programs meet the objective of ensuring that resources are not insulated from the benefits of competition.
- Voluntary RECs, which are not attributable to government support, should be excluded. The Commission should not interfere with private sector valuation of non-jurisdictional co-products determined in market transactions.
Applying MOPR to federal programs that are not expressly exempted by Congress, starting from the date of the Commission’s decision on the scope of the expanded MOPR, is appropriate, subject to the exceptions described above.

BACKGROUND

In March 2016, Calpine Corporation and a group of other generation owners (collectively, “Complainants”) filed a complaint under section 206 of the Federal Power Act. The complaint focused on the alleged market impacts of a then-proposed action by the Public Utilities Commission of Ohio (“PUCO”) to allow approximately six gigawatts of capacity owned by American Electric Power Company, Inc. and FirstEnergy Corporation (“FirstEnergy”) subsidiaries to recover costs under proposed affiliate power purchase agreements (“akin to ‘traditional cost-of-service, rate of-return regulation’”) from retail ratepayers. Complainants argued that the new threat of the capacity market bidding incentives created by the generous rate-recovery warranted extension of the MOPR, which only applied to new gas-fired resources, to existing units participating in the capacity market. PUCO did not ultimately move forward with the power purchase agreements as proposed, and Complainants submitted an amended filing targeting the alleged market effects of Illinois legislation providing for the procurement of Zero Emission Credits (“ZECs”). Complainants maintained that the Illinois policy would affect as much as 2,800 megawatts (“MWs”) of existing nuclear capacity in the PJM market, argued that the ZEC program would pose the same threat to the PJM capacity market as the PUCO proposal, and reiterated its request to expand the scope of the MOPR to existing resources. Neither the original nor the

3 Id. at 25-26 (quoting Affidavit of Joseph Cavicchi ¶ 46).
4 Id. at 2.
5 Calpine Corporation, Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint, Docket No. EL16-49-000 (Jan 9, 2017).
6 Id. at 7, 10-11, 16.
amended complaint mentioned state Renewable Portfolio Standards ("RPS") as a policy posing similar concerns.

The Commission had not acted on the Calpine Complaint by the time that PJM filed its own proposed tariff revisions that aimed to address the interaction of state public policy with the PJM capacity market. PJM’s filing to FERC was preceded by an overly constrained and contentious stakeholder process, in which a majority of stakeholders resoundingly rejected the notion that the capacity market faced an urgent threat requiring changes to market rules. Nevertheless, on April 9, 2018, PJM overrode stakeholder judgment and filed before the Commission two alternate tariff proposals, each of which would bring sweeping changes to PJM’s capacity market construct, known as the Reliability Pricing Model ("RPM"). The first and PJM-preferred option, Capacity Repricing, PJM styled as “[accommodating] state policy actions.” The second, which was preferred by the Independent Market Monitor and dubbed “MOPR-Ex,” PJM openly acknowledged was “punitive” to states whose policies fell within its scope. Clean Energy Advocates timely intervened and opposed both sets of tariff changes—submitting evidence

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7 See Protest of Clean Energy Advocates at 25-30, Docket No. ER18-1314 (May 7, 2018) ("Clean Energy Advocates Protest") (describing frustrations of many stakeholders with a process that was too rushed, failed to identify a clear problem in the market, and ignored majority stakeholder support for the status quo).

8 PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the Capacity Market, Docket No. ER18-1314 (Apr. 9, 2018) ("PJM Filing").

9 Id. at 6.

10 Id. at 53, 56, n.138.
and expert reports demonstrating the proposals would result in unjust and unreasonable rates as well as undue discrimination to consumers and/or resources.\textsuperscript{11}

On June 29, 2018, the Commission issued the Order, which includes three legal findings. It first considers and then rejects each of the Capacity Repricing and MOPR-Ex tariff revisions proposed by PJM as unjust and unreasonable under section 205 of the Federal Power Act.\textsuperscript{12} The Commission also concluded on the basis of the consolidated proceedings that “PJM’s existing Tariff is unjust and unreasonable and unduly discriminatory”\textsuperscript{13} pursuant to Federal Power Act section 206.\textsuperscript{14} In finding that PJM’s existing tariff is not just and reasonable, the Commission asserted that, “records in both cases demonstrate that states have provided or required meaningful out-of-market support to resources in the current PJM capacity market, and that such support is projected to increase substantially in the future.”\textsuperscript{15} The Commission did not, however, define “meaningful” support or “out-of-market support.” The Commission consolidated the existing dockets and initiated a paper hearing in which parties may submit additional argument and evidence to address open issues and questions raised in the Order.\textsuperscript{16}

The Commission’s Order directed that the replacement rate must provide “a just and reasonable means of addressing the market impacts of out-of-market payments.”\textsuperscript{17} It indicated that, to do so, the tariff changes should include an expanded MOPR “with few or no exceptions” that

\textsuperscript{11} See generally Clean Energy Advocates Protest; see also Order at PP 28, 30 (granting Clean Energy Advocates’ timely-filed motions for intervention).
\textsuperscript{12} PJM Capacity Market Order at PP 32-106.
\textsuperscript{13} Id. at P 150.
\textsuperscript{14} Id. at PP 107-175.
\textsuperscript{15} Id. at P 149.
\textsuperscript{16} Id. at PP 149, 157.
\textsuperscript{17} Id. at P 158.
covers "out-of-market support to all new and existing resources" regardless of type. The Commission stated that, "the expanded PJM MOPR will ensure that all resources participating in the capacity market, whether or not these resources receive out-of-market support, offer competitively." With respect to the scope of the MOPR, the Order requested comment on several issues, including:

- The appropriate scope of out-of-market support to be mitigated by the expanded MOPR.
- The types of MOPR exemptions that should be included.
- Whether an exemption should be included for self-supplied resources.
- What, if any, exceptions should be added to the MOPR for existing resources in the capacity auction.

Clean Energy Advocates have participated in subsequent PJM stakeholder meetings to discuss these and other open elements related to the replacement rate. Clean Energy Advocates respond in this filing to the positions presented by PJM to stakeholders at its final stakeholder September 11, 2018 meeting before the comment deadline. To the extent that PJM changes its positions in its October 2nd, 2018 comment, Clean Energy Advocates will respond to relevant changes on reply.

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18 Id.
19 Id. at P 162.
20 Id. at P 165.
COMMENT

I. Policing all state policies that affect resource offers remains an arbitrary, unworkable, and unjust and unreasonable approach to ensuring markets are competitive.

Clean Energy Advocates reaffirm here our protest to the approach adopted in the PJM Capacity Market Order. The objections described herein have been previously presented to the Commission in an initial protest and a subsequent request for rehearing of the Order. Clean Energy Advocates’ objections set forth in the request for rehearing remain unresolved by the Commission. We reassert them in this filing in order to be perfectly clear that, by addressing questions and implementation issues raised in the Order, Clean Energy Advocates are not abandoning our foundational objections to determinations in the Order and the initiation of this proceeding under section 206. After summarizing our core objections to the Order and this proceeding, section II of this comment turns to addressing the implementation issues raised in the Order. The discussion in section II presumes arguendo that the challenges raised in Clean Energy Advocates’ Request for Rehearing have ultimately been resolved without changes to the Commission’s initial Order.

Clean Energy Advocates continue to object to the Commission’s finding that PJM’s existing rate is not just and reasonable or unduly discriminatory, a threshold determination that must form the basis for the Commission’s approval of a replacement rate under section 206.


23 Emera Maine v. FERC, 854 F.3d 9, 24 (D.C. Cir. 2017); Colorado Office of Consumer Counsel v. FERC, 490 F.3d 954, 956 (D.C. Cir. 2007); see also Clean Energy Advocates Request for Rehearing at 10-13.
finding is not supported by sound reasoning, is contradicted by basic economic theory, and is not backed by substantial evidence. The Commission’s determination that differences in state policies result in rates that are not just and reasonable or are unduly discriminatory also infringes on states’ proper role under the Federal Power Act and discriminates among similarly situated resources in violation of the Federal Power Act.

In the context of the inextricably linked wholesale and retail electricity markets in which state and retail policy choices inevitably affect wholesale markets, the Commission has failed to explain why some state policies that confer a competitive advantage to certain resources are harmful to market “integrity,” but others are not. The Commission has long treated costs or financial incentives that result from differing backdrop state policies as part and parcel of resource economics. The Commission’s determination that “circumstances in PJM have changed” appears to have been based on an arbitrary focus on particular sources of revenue external to the

24 See Clean Energy Advocates Request for Rehearing at 13-35.
25 Id. at 37-40.
26 See Clean Energy Advocates Request for Rehearing at 26; Clean Energy Advocates Protest at 107-109 (citing Gramlich Affidavit at section V; PJM Interconnection, L.L.C., 137 FERC ¶ 61,145 at P 242-244 (2011) rejecting claims that “revenues that occur in the ordinary course of a market participant’s business—but which are not available to the benchmark unit”—should be ignored when considering whether a resource’s bid is “consistent with the competitive cost-based cost of new entry”); PJM Interconnection, L.L.C., A Review of Generation Compensation and Cost Elements in the PJM Markets, at 15 (2009); PJM Interconnection, L.L.C., 126 FERC ¶ 61,145 at P 42 (Feb. 19, 2009); New York State Pub. Serv. Comm’n et al., 158 FERC ¶ 61,137 at P 33 (Feb. 3, 2017); PJM Interconnection, L.L.C., 119 FERC ¶ 61,318 at P 150 (June 25, 2007); PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at PP 106-108 (Dec. 22, 2006)). The only clear exception to this rule is that state retail authorities cannot set wholesale market rates, and state measures must be “untethered to a generator’s wholesale market participation” Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1299 (2016) (internal quotation marks omitted). In such cases, the Commission has already approved of rules to adjust the offer prices to reflect Commission-approved rates for those wholesale products. See PJM Interconnection, L.L.C., 135 FERC ¶ 61,022 at P 139 (Apr. 12, 2011).
27 Order at P 153.
market (state climate policies) that overlooks other policies that have long had the same type of economic effect on the PJM capacity market. The Commission failed to make any finding whatsoever regarding the history and extent to which other state policies, such as cost recovery for uneconomic resources provided through retail ratemaking, exist and have affected capacity market prices. Before it can mandate changes to the rate to address the alleged market threat, the Commission must explain why it is departing from its precedent of treating competitive advantages or disadvantages that result from differing state regulatory environments as part of resource economics that must be reflected in resource offers. Moreover, it must justify any discriminatory approach that treats only certain advantages (e.g., revenues) as a threat to the market while ignoring other policy differences (e.g., shielding generators from liability) that have the same economic effect of providing a competitive advantage to certain resource classes.

The Commission cannot appropriately tailor a replacement rate to address the threat of market harm unless it has both explained what the harm is, and why, under the Commission’s rationale, resources that are similarly impacted in their ability to compete by federal, state, or retail policies do not pose that same harm. The Commission has never met its burden to do so, and that failing infects not only the PJM Capacity Market Order, but the Commission’s work on a replacement rate in this proceeding. A replacement rate mandated by the Commission under section 206 is unlawful unless tailored to address the flaws that render rates unjust, unreasonable, or unduly discriminatory.28

28 Colorado Office of Consumer Counsel, 490 F.3d at 956 (explaining that the scope of the replacement rate ordered by the Commission is appropriately tailored to the scope of the Commission’s finding that rates are unjust and unreasonable); Clean Energy Advocates Request for Rehearing at 22.
Further, the Commission’s rationale for selectively addressing some policies that impact resource competitiveness and not others cannot contradict the evidence before it, nor defy basic economic principles. Policies—at federal, state, or local levels—that provide a competitive advantage to some resource types and not others are not new. Nor are the current state policies targeted by the Order more sweeping or substantial than other policies that have long affected the market. By PJM’s own account, the capacity market has thrived and ably achieved its objective of securing adequate capacity at reasonable cost. It has done so notwithstanding that federal, state, and local policy preferences have long shaped the resource mix without mitigation. The Commission cannot base its finding on the fiction that state climate policies affect more resources or have a greater impact on the competitiveness of resources than other policies. Likewise, the Commission cannot build its replacement rate on a foundation that contradicts well-established economic principles. The Commission cannot deem policies that correct for market inefficiency

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29 Mobil Pipe Line Co. v. FERC, 676 F.3d 1098, 1104 (D.C. Cir. 2012) (“[W]hen an agency is statutorily required to adhere to basic economic principles and competition principles . . . the agency must adhere to those principles when deciding individual cases.”); Clean Energy Advocates Request for Rehearing at 34.


31 Clean Energy Advocates Protest at 40-42 (incumbent generators have received many large state tax breaks that are documented as far back as the 1950s, 60s, and 70s).

32 Id. at 35-38 (“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.”) (quoting PJM, Resource Investment in Competitive Markets at 24 (May 5, 2016), available at http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx (“PJM Resource Investment Whitepaper”). Clean Energy Advocates view recent procurement well beyond reserve margins to be inefficient and costly to customers. In any event, by all objective measures, reliability in PJM is not under threat.
by valuing externalities as *anti-competitive*.\(^{33}\) This is particularly so where all evidence demonstrates that the climate policies targeted by the Order are efficient in that they secure environmental benefits for a price at or below the independently assessed and externally validated conservative estimate of the social cost of carbon.\(^{34}\)

Finally, the Commission must abide by its limited role under the Federal Power Act. The Commission is not empowered to overturn the determinations of competent state regulators as to the value of environmental externalities.\(^{35}\) By finding that the “true” economics of a resource cannot include valuation of certain attributes or services that are not sold within wholesale capacity market, the Commission is making a determination that the economically correct valuation of these

\(^{33}\) Clean Energy Advocates Request for Rehearing at 33 (citing Mankiw, N. Gregory, *Principles of Economics*, at 195-96 (Chapter 10 – Externalities) (2011); see also Mankin, N. Gregory at 213 (“Sometimes the government prevents socially inefficient activity by regulating behavior. Other times it internalizes an externality using corrective taxes.”); Flynn, Sean Masaki, *Economics for Dummies*, at 196 (2018) (“negative externalities such as pollution cause overproduction by shifting supply curves.”); Cooper, R. and Andrew, John, *Economics – Theory Through Applications*, at 522 (2011) (“In the presence of externalities, distortions in the market and some type of government intervention may be warranted. Often, that intervention takes the form of taxes and subsidies that alter individual incentives to encourage behavior that promotes economic efficiency.”) (emphasis in original); McAfee, Preston and Lewis, Tracy, *Introduction to Economic Analysis*, at 156 (Chapter 7 – Externalities) (“Externalities create a market failure—that is, a situation where a competitive market does not yield the socially efficient outcome.”)).

\(^{34}\) See Clean Energy Advocates Request for Rehearing at 32-36 (compiling citations to record evidence, economist textbooks, and academic studies documenting the value of internalizing market externalities and net benefits of RPS programs); see also Clean Energy Advocates Protest at 19; Mai, et al., “A Prospective Analysis of the Costs, Benefits, and Impacts of U.S. Renewable Portfolio Standards,” NREL (2016) at xi, available at http://etapublications.lbl.gov/sites/default/files/lbnl-1006962.pdf (“When comparing the costs and monetized benefits, we find that the benefits [of RPS programs] exceed the costs, even when considering the highest cost and lowest benefit outcomes.”).

\(^{35}\) See Clean Energy Advocates Protest at 52-57 (detailing how erroneously treating the effects of state policies as market failures would frustrate state policy objectives).
attributes or services is zero. The Commission lacks the authority and competency to make that determination.

II. If the Commission must expand the MOPR to mitigate “out-of-market” payments, it must do so consistently, target the most significant payments, and carve out policies which are not demonstrably linked to impacts on the market.

In the PJM Capacity Market Order, the Commission stated that an expanded MOPR must provide “a just and reasonable means of addressing the market impacts of out-of-market payments.” The expanded MOPR must address both new and existing resources regardless of type and include “few or no exceptions.” The Commission requests input regarding “[t]he appropriate scope of out-of-market support to be mitigated,” including whether to include federal sources of support and the scope of any exceptions to the MOPR. We offer here some important guideposts to inform the Commission’s decisionmaking, setting aside the objections set forth in section I solely for the purpose of argument and constructive engagement.

a. The Commission must recognize that over-mitigation results in rates that are unduly discriminatory or not just and reasonable.

The Commission has long relied upon a core principle in evaluating the appropriate scope of the MOPR, across widely varying Regional Transmission Organization and Independent System Operator contexts and under very different Commission compositions. As its north star, the Commission has strived to strike the right balance between over and under-inclusiveness.

36 PJM Capacity Market Order at P 158.
37 Id.
38 Id. at P 165.
The Commission has thus always acknowledged that applying an administrative screen on offers has a real cost; over-mitigation also results in rates that are not just and reasonable or are unduly discriminatory. This approach inherently recognizes that many resources can in fact offer at prices lower than their administratively-determined offers, and forcing resources to prove this through burdensome additional process is not costless. Developers of new resources and owners of existing ones subject to MOPR would not reasonably invest in cost-reducing practices or equipment unless the benefits exceed the transactional costs of navigating the additional administrative process. The transactional costs of applying a MOPR screen or unit-specific review are thus reflected in capacity market offers and ultimately borne by customers. To the extent that MOPR determinations force inappropriately high offer prices, a non-optimal mix of resources may be selected, needless inflating capacity market prices.

The Commission has no basis here to depart from this longstanding principle. In devising the expanded MOPR, it should limit its scope to cover only what is needed to address the purported market threat. Setting a goal of rooting out all “price suppression” ignores the other side of the equation: the costs of extensive administrative screening of offers and the inevitability that administratively-determined offers are set too high and force some economic, more efficient resources to bear excessive transaction costs.

_L.L.C_, 137 FERC ¶ 61,145 at P 49 (Nov. 17, 2011) (concluding a certain MOPR exception was not necessary because “the unit-specific review process available to sellers will protect against over-mitigation”); _ISO New England, Inc_, 135 FERC ¶ 61,029 at P 313 (Apr. 13, 2011) (weighing concerns about over-mitigation in searching for a “reasonable approach”); Commission Staff Report, _Centralized Capacity Market Designs Elements_, Docket No. AD13-7-000 at 26 (Aug. 23, 2013), available at https://perma.cc/SME5-XWFD (“As a general matter, any market power mitigation construct should be designed to constrain actions that will alter competitive market outcomes, while avoiding over-mitigation that can deter from the formation of accurate market price signals for investment in capacity resources.”).

_FCC v. Fox Television Stations, Inc_, 556 U.S. 502, 515 (2009) (reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy); _Louisiana Pub. Serv. Comm’n v. FERC_, 772 F.3d 1297, 1303 (D.C. Cir. 2014).
resources out of the market. As discussed in greater detail infra section II.b-c, the Commission should apply this principle by (1) focusing the trigger for applicability to MOPR on the largest and most sweeping forms of government support that are most likely to affect bidding behavior and market outcomes; (2) not exempting retail cost-recovery from MOPR, because it substantially affects the bidding behavior of some 40,000 MWs of capacity in PJM; and (3) exempting state RPS programs, which are not clearly linked to changes in bidding behavior or market outcomes, affect relatively little capacity in PJM’s market, and would be particularly burdensome to subject to the MOPR.

In addition, as the Commission has concluded previously, the MOPR must incorporate a unit-specific exemption to allow resources to demonstrate that their costs are lower than the administratively-determined reference price. This is particularly so where the MOPR will apply to a much more expansive category of resource types, many of which continue to undergo rapid changes in their technical capabilities and economics.

Finally, setting a resource size threshold for applicability of the MOPR, as the Commission has approved in the past, is critical to avoid the over-mitigation that results in rates that are not just and reasonable. Clean Energy Advocates thus support PJM’s proposal to set a 20 MW threshold for applicability of the MOPR.

41 *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 26 (May 2, 2013) (concluding that PJM proposed categorical exemptions were not just and reasonable without a unit-specific review process to consider other offers that might be cost-justified) (overturned on procedural grounds); see also Brief of Respondent FERC, *NRG Power Marketing, LLC v. FERC*, Nos. 15-1452, 15-1454, 2016 WL 5405117, at *20-21 (D.C. Cir. Sept. 27, 2016) (defending its decision on the grounds that over-mitigation does not result in just and reasonable rates).
b. The Commission must not employ the MOPR to block the economic effects of programs that enhance market competition by correcting for well-understood market externalities.

While, as stated in section I, Clean Energy Advocates oppose the Commission’s new approach of policing state policies to determine which constitute “subsidies” that must be mitigated; to the extent the Commission persists under this framework, it must do so in a manner that does not defy basic economics. Simply put, the valuation of services afforded by resources in markets external to the capacity market are not “uneconomic” out-of-market payments. Further, the environmental attributes being bought and sold in PJM’s renewable energy certificate (“RECs”) markets help to remedy market inefficiencies by incorporating real costs of electricity production that are not otherwise being accounted for in the market.\(^{42}\) RECs help to correct for market externalities that are objectively defined, well-documented, and recognized in mainstream economic theory. As such, there are objective criteria to determine whether these payments are efficient or not.\(^{43}\) The Commission need not rely on assessment of the legitimacy of a policy or policymakers’ intent. Sound economic theory provides a basis for distinguishing between the valuation of well-established market externalities from interventions that constitute “out-of-market payments” under the Order’s rationale.

\(^{42}\) Clean Energy Advocates Request for Rehearing at 32-35 (compiling record support and economics textbook citations).

\(^{43}\) Id. at 33 (citing, inter alia, Comments of the Institute for Policy Integrity at New York University School of Law, Docket No. ER18-1314 at 15, n.47 (May 7, 2018) (noting that zero-emission credits based on the Social Cost of Carbon were grounded in a ‘consensus based’ approach, relied on peer-reviewed academic literature, disclosed relevant limitations, and adequately planned to incorporate new information through public comments and updated research.”))
c. The Commission should only target policies that have a demonstrable link to changed bidding behavior, and must not arbitrarily exempt those that have a similar effect on market participants.

The Commission aims to address the “market impacts of out-of-market payments” on the theory that resources receiving such payments can cause significant “price suppression.” The Commission sets as its objective to identify resources that receive out-of-market value that affects resource bidding behavior such that market clearing prices are suppressed. Thus, there are two components to the standard the Commission sets for its new MOPR: (1) Does the out-of-market incentive demonstrably change economic bidding behavior? and (2) Does the incentive affect sufficient capacity in a large enough degree to matter (with respect to market clearing prices)? In the PJM Capacity Market Order, the Commission has ruled out consideration of intent, signaling that under this new framework its purpose is not deterrence. It is indifferent to whether the policy action is motivated by financial benefit to a net buyer, and asserts that it will only distinguish between policies based on their economic effect, not their purpose.

The Order thus points to a number of conclusions about the scope of an expanded MOPR. First, the Commission cannot exempt the largest and most substantial form of out-of-market revenue from the scope of the MOPR: revenue provided to resources via cost-recovery under state-administered retail rates. These state-supported actions are economically indistinguishable from the kinds of policies that the Commission determined render PJM rates not just and reasonable or unduly discriminatory, insofar as they represent a source of income to the generation owner other

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44 PJM Capacity Market Order at P 158. Again, as described in Clean Energy Advocates Request for Rehearing and reiterated in section I above, the Commission has not articulated a reasonable explanation of which policies cause market harm and how, or backed that theory by record evidence. Without waiving that core objection, this subsection offers the Commission guidance assuming the counterfactual—that the Commission had adequately established that some set of resource offers are too low and result in price suppression, which in turn manifests in some market harm.
than PJM-administered wholesale markets that likely affect bidding behavior. Moreover, they have a significantly larger effect on market clearing prices because of their scale and broad sweep.

Second, the Commission must more carefully consider how state RPS programs actually function in determining whether they result in “out-of-market payments” that pose a threat to market outcomes. With a greater understanding of how the REC markets in PJM are actually implemented and ultimately result in payments to resources, it is evident that these programs do not provide the kind of direct and pre-determined revenue stream that would allow these resources to change their bidding behavior. Moreover, even after full achievement of the state RPS targets, the scale and sweep of these programs remain minimal compared to that of retail cost-recovery. As such, all or most RPS programs should be excluded from the definition of an “actionable subsidy.”

Third, the role competition plays in determining which resources receive RECs provides an independent ground for excluding RPS programs from the scope of an actionable subsidy in the PJM replacement tariff. To the extent that a key motivation behind the Commission’s Order is to ensure resources are not insulated from competitive forces that drive innovation and efficiency and properly align investor incentives to the benefit of customers, the competitive REC markets within PJM do not afford protection from those economic forces.

Fourth, PJM’s focus on identifying actionable subsidies based on anticipated revenue is inadequate, as it ignores factors that affect the potential for resources to impact market price. Focusing on the relative size of the incentive compared to expected revenue does not account for (1) the potential for multiple programs to have a cumulative effect on a single resource, (2) the total quantity of capacity provided by the resource impacted by the government incentive, or (3) the absolute value of the incentive—each of which may increase the potential for changes in
bidding behavior to actually affect market outcomes. However, Clean Energy Advocates generally agree with PJM’s approach to address newly enacted federal programs, to the extent not explicitly exempted from that treatment by Congress, to the same extent as state actions.

1. Resource cost-recovery under state-administered rates is the largest and most substantial source of out-of-market revenue that leads to changed bidding behavior.

PJM proposes to include a self-supply exemption to its definition of actionable subsidies that would be subject to the expanded MOPR. In practice, this would exempt from the MOPR capacity sellers, which are vertically integrated utilities or public power entities, potentially including rural cooperatives that offer as price-takers into the RPM under the “self-supply” provisions of the PJM tariff. These entities typically offer as price-takers because they do not depend on the capacity market to provide for their capacity costs, as the terms of their cost recovery may already be determined by a retail regulator, or may be subsequently determined without regard to whether or not the resource cleared in the capacity market.

A number of stakeholders support a self-supply exemption arguing, for example, that vertically integrated utilities are “longstanding business models for capacity procurement” that should not be subject to mitigation as a “subsidy.” PJM proposes to apply net short and net long tests similar to a previous MOPR exemption for self-supply. As set forth in section I, Clean Energy Advocates agree with the broader point that the Commission should not place itself in the role of policing state policies. Under the framework set out under the Order, however, the Commission cannot reasonably ignore the market impacts of resource cost recovery under state-administered rates.

45 See e.g., PJM Filing at 73. To the extent that these are longstanding business models affecting large quantities of capacity in PJM, this merely demonstrates that circumstances have not changed with regard to the tendency of units to make capacity market offers based on regulatory factors outside RPM that affect revenues and costs.
rates. The Commission cannot address “the market impacts of out-of-market payments” by ignoring the most significant and pervasive source of out-of-market revenue in the PJM footprint.

To the extent that the Commission is concerned by out-of-market payments that “allow the supported resources to reduce the price of their offers into capacity auctions below the price at which they otherwise would offer absent the payments” which may therefore result in “lower auction clearing prices,” there is no economic distinction to be made between retail rate-recovery and other forms of state policy that the Commission has determined have an anti-competitive effect on bidding behavior. Capacity sellers that recover capital, maintenance, or other significant supply costs through retail cost-recovery can offer at a price that they would not be able to absent such cost-recovery. If the resource’s costs of providing capacity were reflected in the resource offer, the offer would incontrovertibly be higher. Indeed, PJM elsewhere acknowledges this kind of rate-recovery is an “explicit subsid[y].”

Moreover, retail cost-recovery affects substantially more generation in PJM than other state policies targeted in the Order, and typically provides much larger out-of-market payments. According to PJM, about 25 percent of generation is owned by traditionally regulated entities that are provided cost-of-service rates. By comparison, again using PJM’s figures, state RPS programs in PJM in aggregate have a 5,000 MW target today, which would comprise only less than 5 percent of generation in PJM if all of that capacity participated in the RPM (and it does

46 PJM Capacity Market Order at P 2.
47 PJM Resource Investment Whitepaper at 35.
48 PJM Filing at 8-9.
49 Id. at 27 (estimating “around-the-clock” capacity needed to meet state RPS targets).
not). Moreover, retail cost-recovery provides much larger payments than the policies targeted by the Order. Both RECs and ZECs are payments for the environmental attributes of generation, i.e., incremental value provided by this capacity due to its zero emissions and associated public benefit. Unlike retail cost-recovery, RECs do not reimburse a resource for its full costs of making the capacity available as supply in the wholesale market. Thus, by definition, retail cost-recovery is a more significant and determinative factor to the bidding behavior of the affected resources than policies that value environmental attributes. Finally, it would turn the logic of the Commission’s Order on its head to exempt retail cost-recovery while applying MOPR to competitive RPS programs. Such an exemption would reward states that eschew competition entirely by remaining vertically integrated, allowing them to reap the benefits from competitive markets, while punishing deregulated states that have embraced market principles and adopted competitive processes to meet RPS program goals.

Specific examples demonstrate that retail cost-recovery imposes precisely the same market effects that the Commission believes threaten market integrity. The Commission seeks to “protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support to keep existing uneconomic resources in

50 See Id., Attachment 1 to Giacomoni Aff. Giacomoni estimates that state renewables programs account for 5,000 MW of “around the clock” capacity. This equates to roughly 8750 MW of UCAP, assuming those RPS programs are satisfied by resources with a weighted average capacity value of 42.63% and an average weighted capacity factor of 24.34% (assumptions that are in line with the current proportions of wind versus solar that meet RPS demand). See Clean Energy Advocates Protest, Appendix B, Goggin Affidavit, ¶¶ 11-12. Total UCAP cleared in the 2021/2022 RPM Base Residual Auction was 163,627 MW, and an additional 22,878 MW of capacity submitted offers but did not clear. See 2021/2022 RPM Base Residual Auction Results, p. 19. available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx.
operation, or to support the uneconomic entry of new resources.\textsuperscript{51} Retail cost-recovery decisions result in both retention of existing resources, notwithstanding their uneconomic going-forward costs, and entry of new resources even though more competitive alternatives are available. For example, in 2008 the Virginia State Corporation Commission approved recovery for costs associated with the construction of the $1.8 billion Virginia City Hybrid Energy Center, “a carbon capture compatible, clean-coal powered 585 megawatt (nominal) coal-fueled generating plant.”\textsuperscript{52} Recent analysis concluded that the plant is not economic when compared to the costs of an existing natural gas combined cycle unit.\textsuperscript{53} Rate-recovery of capital costs of the power station continues in 2018, which predictably allows that power plant to bid in its capacity at less than its going-forward costs.\textsuperscript{54} Rate-recovery is such a predictable means to ensure that uneconomic plants continue to operate that it has become an explicit business strategy for market participants who own significant quantities of uneconomic capacity.\textsuperscript{55} Transfer of a nearly 2,000 MW merchant coal generator, for

\textsuperscript{51} PJM Capacity Market Order at P 150.
\textsuperscript{54} Application of Virginia Electric and Power Company, For a revision of rate adjustment clause: Rider S, Virginia City Hybrid Energy Center Case No. PUR-2018-00086 (June 12, 2018).
\textsuperscript{55} For example, FirstEnergy’s CEO described his plan to shift generation to rate-base to shield it from merchant competition in a November 2016 investor call. Reiterating that FirstEnergy “do[es] not believe Competitive Generation is a good fit for FirstEnergy,” he warned that “competitive market conditions continue to deteriorate, punctuated by weak power prices,
example, to a West Virginia regulated entity resulted in over $50 million per year in cost-recovery that the resource would not have earned in the markets. The costs recovered from state retail customers that have no alternatives need not be reflected in the resource’s bid into the capacity market, and it is predictable that this unit will bid in as a price-taker notwithstanding its significant going-forward costs.

PJM’s proposal to apply a net short-net long test does not alleviate these market effects. The net short-net long exception that applied previously in PJM’s tariff worked within the context of a MOPR that targeted capacity sellers based on intent. If MOPR only applies where a capacity seller aims to gain financial advantage by selling capacity cheaply because, for example, they are net short and must buy more than they sell, then it makes sense to create exceptions for capacity sellers that lack that financial incentive. But the Commission abandoned the focus on the aims of the capacity seller in the Order. It is simply inconsistent with the Commission’s Order to retain a net long-net short screen because that screen has no relation to the actual price suppressive effect of the self-supply exemption. If the Commission reopens the door to applying MOPR based on the insufficient results from recent capacity auctions and anemic demand forecasts. The fact is Competitive Generation is weighing down the rest of our company.” The CEO also expressed his goal “to keep as many of our generating units running as possible.” Seeking Alpha, FirstEnergy (FE) Q3 2016 Results - Earnings Call Transcript (Nov. 4, 2016), available at https://seekingalpha.com/article/4019708-firstenergy-fe-q3-2016-results-earnings-call-transcript.

PJM’s Independent Market Monitor has criticized the transfer of merchant plants to rate-base as an “uneconomic subsidy.” See, e.g., Comments of Independent Market Monitor for PJM at 1, EC17-88-000 (May 26, 2017) (“[t]he Transaction amounts to providing subsidies for an uneconomic unit, which, if approved, would harm the public interest in a well functioning PJM competitive market design.”).

incentives of the capacity seller, it must equally apply that standard to other resources and market participants—including, for example, renewable energy resources receiving RECs, which the Commission has long-recognized are a poor tool for purposefully achieving lower market clearing prices.\textsuperscript{58} If intent does not matter, but only the existence of a payment that could allow for a change in bidding behavior that is, in turn, capable of impacting price, then the self-supply exemption cannot stand.

2. \textbf{RPS programs do not typically provide a direct and predictable revenue stream that could lead to changed bidding behavior.}

The PJM Capacity Market Order describes state RPS programs as providing a specific $/MW-day value of out-of-market revenue to an eligible resource and suggests such support will continue to be significant in the future.\textsuperscript{59} The Order thus evinces both a misconception of how the REC markets function to achieve state RPS program goals, and a failure to acknowledge the diversity of transactions that comprise REC markets. The details of how these programs function is critical because this information demonstrates that the vast majority of REC transactions \textit{cannot materially affect market participant’s bidding behavior}, and thus do not pose the risk of price suppression that the Commission aims to address.

State RPS programs vary considerably in their specific terms\textsuperscript{60} but share a core commonality that they do not function by creating a specific price support for one or more specific resources or class of resources. Rather, by setting requirements for load serving entities to buy

\textsuperscript{58} Such a test would also need to account for the fact that states rather than resource owners create RECs and ZECs; as such they are not a price suppressive tool used by resource owners to manipulate market prices and application of MOPR to them would be inappropriate under this rationale.

\textsuperscript{59} PJM Capacity Market Order at PP 151-152.

\textsuperscript{60} \textit{See} Clean Energy Advocates Protest at 10, App. A.
RECs, which constitute the environmental value of a certain quantity of renewable energy generation, many state RPS program generate demand for renewable energy. RECs that fulfill the requirements of state RPS programs are “compliance RECs” or “mandatory RECs.” The value of a compliance REC is generally affected not only by the terms of the state RPS program, but also by the terms of other states RPS programs (because most RPS programs allow for at least some form of cross-boundary REC sale) and also by demand for “voluntary RECs”, i.e., credits that are valued not because of a state-mandated RPS target but because of private, voluntary transactions undertaken by corporate buyers, residential consumers, and other entities. In short, REC prices are not fixed, but rather are determined by supply and demand in the REC markets and are driven down by competition among renewable energy providers.

Importantly, unlike other forms of state policy such as tax incentives, a renewable energy project developer cannot predictably rely on a certain revenue stream at the point in time it first seeks to enter the RPM, three years before the delivery year. First, as exemplified in Figure 1 produced by the National Renewable Energy Laboratory, REC prices are volatile.

RECs are simply a contractual right to claim the environmental attributes to renewable energy usage. RECs do not transfer energy, capacity, or any of the other services or value streams that result from renewable energy generation (although a transaction can bundle sale of these different products together). See Comments of Advanced Energy Economy, at Attachment A, Renewable Energy Certificates Market Primer, p. 1, EL18-178 (Oct. 2, 2018).

Id. at Attachment A, p. 2.

Second, RECs are created and registered into a tracking system based on each MWh of generation, well after the applicable capacity market auction has already occurred. As such, resources typically cannot depend on a particular revenue stream as they make an offer into RPM. Only in the rare case where a resource is able to secure a long-term contract for its RECs can this revenue stream predictably impact its bidding behavior. Yet it is well documented that REC contracts are predominantly short-term in nature, and are often executed close in time to the actual energy generation. One commentator has gone so far as to suggest that, “[b]ecause they are not


NREL completed a study examining the role RECs play in financial investment decisions, and concluded that investors and lenders will “not recognize REC revenue in their financial decision unless a contract is in place.” Further, while longer-term (i.e., around 5-year) contracts are generally available in traditionally regulated states, that is not the case in restructured states where load projections are uncertain and, therefore, future REC demand. Edward Holt et al., The Role of Renewable Energy Certificates in Developing New Renewable

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able to capture the full potential value of RECs in long-term contracts, renewable energy developers may not be able to realize the full potential benefits of RECs when project financing their facilities.\textsuperscript{66}

While the link between RPS programs and the potential for changed bidding behavior is attenuated, the administrative challenge of tracking whether REC revenues are due to state policy, rather than voluntary private demand is substantial. REC marketers commonly purchase RECs directly or via brokers, managing price volatility by aggregating RECs from different resources for energy generated over different years.\textsuperscript{67} A REC transaction may pass through multiple parties before ultimately reaching a buyer facing compliance targets or a voluntary REC purchaser. Multi-year REC contracts that can transform volatile REC market revenues into a financeable cash flow typically occurs through a private broker, and that payment will be a risk-adjusted to reflect expectations and risks around not only changes to state policy goals but also future private, voluntary demand for REC. It is administratively challenging to parse out the extent to which the payment is driven by state programs.

In short, the generator may have little way of knowing whether it has sold mandatory or voluntary RECs. As discussed further in subsection d infra, the distinction matters. The

\textsuperscript{66} Mack et al., supra note 65.

Commission cannot justify discounting market demand for a product or service; private sector valuation of a commodity generated by a resource is undeniably a part of its “true economics.” Yet, voluntary RECs are a rapidly growing part of the REC market, driven in part by large corporate buyer commitments to renewable energy or sustainability goals.\textsuperscript{68} Figure 5 from the National Renewable Energy Laboratory shows the steady growth of voluntary RECs\textsuperscript{69}, but does not capture the significant new, record-breaking corporate commitments to renewable energy procurement in 2017 and 2018.\textsuperscript{70}

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\textsuperscript{69} \textit{Id.} at 8.

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In sum, the administrative cost of identifying revenue streams from compliance RECs will be high, while the actual effect of these RECs on market outcomes would be minimal. An exception for state RPS programs is warranted as the Commission can achieve the objectives articulated in the PJM Capacity Market Order of ensuring market integrity, while avoiding over-mitigation that results in rates that are not just and reasonable.

3. Competition in PJM REC markets provides independent grounds to exempt state RPS programs.

The Commission’s Order appears to make a key distinction in setting out the aims of the expanded MOPR. The Commission is not seeking to address every low offer by resources participating in the PJM capacity market, but rather explains that “there is an important difference between a resource that offers low as a result of competition in the market and one that offers low because a state subsidy gives it the luxury of doing so.” The Commission describes its concern

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71 As discussed in Section II.d, it would exceed the Commission’s role under the Federal Power Act to apply MOPR to a resource based on the receipt of compensation pursuant to a non-FERC jurisdictional voluntary REC contract.

72 PJM Capacity Market Order at P 153.
that “[t]he state subsidy protects the latter resource from the potential downside of that bidding behavior.” But renewable energy project developers and resource owner/operators cannot simply depend on a guaranteed stream of revenue because of state RPS programs. Resources must compete to deliver RECs, and face a real risk of being outcompeted in that venture by other resources. Less efficient, costlier resources will lose out in REC markets or in competitive procurements to more economic resources. To the extent that a resource’s profitability depend on receiving a certain value from those RECs, resources are not insulated from the risk of failure and, consequently, market exit or inability to enter the market in the first place. Indeed, it is precisely this substantial degree of competition and the steep risk of failure for uneconomic resources that support the vibrant financial market of REC marketers and brokers. While there are forms of government action that guarantee provision of a payment or incentive to specific resources or a class of resources, such as tax incentives, local economic development incentives, or even a particular cost-recovery decision, RPS programs do not operate in this fashion. The role of competition in state RPS programs thus provides an additional basis for the Commission to exclude these policies from the definition of an actionable subsidy that triggers MOPR.

4. **PJM’s proposed definition of a material actionable subsidy does not identify policies that have clear links to changed bidding behavior and price suppression.**

In its September 11th stakeholder meeting, PJM reported to stakeholders that it “plans to use [the] definition of Material Subsidy and Actionable Subsidy from [the] April 9 filing with

73 *Id.*

some modifications around when it is an actionable subsidy.”

PJM also reported it will consider a subsidy “material” if it “is greater than 1% of such Capacity Resource’s actual or reasonably anticipated total revenues from markets administered by PJM.” As in the original PJM April 9th filing, PJM appears to propose to define a “subsidy” as:

payments, concessions, rebates, or subsidies directly from any governmental entity connected to the construction, development, operation, or clearing in any RPM Auction, of the Capacity Resource, or . . . other material support or payments obtained in any state-sponsored or state-mandated processes, connected to the construction development, operation, or clearing in any RPM Auction, of the Capacity Resource.

However, it appears PJM will update that proposal to “only look at subsidies that the Capacity Market Seller is ‘entitled to’ at the time the election for Resource Carve Out is due.” PJM also appears to be changing the exemptions presented in the April 9th filing, as its report to stakeholders did not include its previously proposed exemption for general economic development and local siting incentives and changed the scope of its exemption for federal subsidies. PJM now proposes to exclude only “[c]ongressional actions prior to March 21, 2016” unless programs enacted after

76 Id.
77 PJM Filing at 69.
78 PJM, PJM Proposal Including Stakeholder Input (Sept. 11, 2018), available at https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx. PJM also explained that it would consider all renewable energy resources to be “entitled to” REC revenues and would determine whether such revenues were material based on historic REC prices. Taken together, these positions amount to applying the MOPR to an entire class of resources based on arbitrary and flawed assumptions regarding the potential value of any out-of-market revenue that might be received.
that date include an “an express statement . . . indicating the subsidy should not be mitigated under the FPA.”

PJM’s minor adjustments to its proposed definition of a “material” and “actionable” subsidy do not address the deep flaws with its approach. PJM focuses on whether an incentive is large relative to the resource’s revenue, but ignores whether the government action affects a single resource or the whole fleet. Similarly, PJM ignores the absolute value of the incentive. The approach is inconsistent with the aims of the Commission’s Order, which seeks to address the “market impacts of out-of-market payments.” It is illogical to suggest that a subsidy that is slightly over one percent of a 21 MW resource’s revenue will have significant market impacts, but a subsidy that is slightly under one percent of a 1000 MW resource’s revenue will have no significant effects (though the latter is some 50 times larger in absolute magnitude than the former); or that the former subsidy is significant while the latter is not, if the latter subsidy affects not just one 1000 MW unit, but 20 or 30 such units of comparable size. PJM’s test of materiality does not meaningfully track the potential for a policy to affect market prices.

Nor does PJM’s proposed definition target government actions that are most likely to result in changes in resource bidding behavior. A focus on the size of the subsidy relative to the resource is not a good proxy for its effect of bidding behavior or, correspondingly, market outcomes. A large, sophisticated market participant is far more likely to be able to take advantage of a relatively small subsidy (vis à vis the size of the resource) to change its bidding strategy where it sees the potential for financial payoff. It is also far more likely that that strategic change in bidding strategy will result in a change in marking clearing prices.

79 Id.
80 PJM Capacity Market Order at P 158.
PJM also appears to ignore the potential for multiple government actions to affect the same resource, resulting in cumulative payments or support that exceeds the one percent of expected market revenue threshold. Again, it is illogical to assume that a single policy affording a capacity resource just over one percent of its expected revenue in value will cause that resource to alter its bidding strategy, but a resource benefiting from two separate policies that each provide just less than one percent of expected revenue (and cumulatively, a higher total amount of support) is not likely to change its offer.

Any definition of a subsidy triggering MOPR that the Commission ultimately adopts should avoid these logical inconsistencies. If the Commission views price suppression as the key market threat, it should tailor the application of MOPR to policies that have the highest absolute magnitude impact on the greatest total capacity of resources – because such large scale and broadly applicable policies are most likely to have some impact on market outcomes.

5. **The Commission should not arbitrarily exclude some forms of government support.**

As described in the prior section, PJM’s proposed definition of an actionable subsidy includes multiple forms of government support, including “payments, concessions, rebates, or subsidies” and “other material support or payments.”\(^81\) PJM also proposes to expand the definition of an actionable subsidy to include federal support that is newly enacted into law, unless Congress expressly prohibits the mitigation of that new program.\(^82\) Such an open-ended approach that does

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\(^81\) PJM Filing at 69.

\(^82\) PJM, *PJM Proposal Including Stakeholder Input* (Sept. 11, 2018), available at [https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx](https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx). It seems inappropriate that PJM proposes to use the 2016 refund date of the Calpine Complaint in EL16-49 as the point in time at which any new federal program would need an express exemption from mitigation by Congress. Nothing in the
not arbitrarily exclude some forms of government incentive is critical to avoid undue discrimination of similarly situated resources. As Clean Energy Advocates’ subsidy expert Doug Koplow explained in our protest to PJM’s Section 205 filing, the market effects of different government incentives are the same “regardless of the level of government that grants it, the policy instrument used, or the stated purpose for which it was granted.”

Indeed, “[p]olicies that increase revenues, reduce costs, or reduce the uncertainty or volatility of cash flows can all have similar effects on investment and operational decisions.” Koplow explained that targeting only certain forms of policy will inevitably lead to unjustifiable discriminatory impacts:

[C]apital-intensive generation will be more affected by build times, financing conditions, and changes in demand during the build period. Electricity reliant on high volume flows of input fuels are affected by subsidies to key transport links, favorable policies for pipeline building, and subsidies to extraction. Accordingly, PJM’s focus on one category of subsidies will have the effect of discriminating based on technology type.

So long as the government incentive has an equivalent ability to affect resource bidding behavior and market outcomes, it should not be arbitrarily excluded from the definition of an “actionable subsidy” that may trigger MOPR.

d. The Commission must not overstep the bounds of the Federal Power Act by regulating non-jurisdictional transactions such as voluntary RECs.

Voluntary RECs, as discussed above, are not driven by any governmental policy. Instead, private actors decide, based on their own private preferences, to pay for an environmental service

2016 complaint implicates mitigation of federal policies. As such, to the extent the Commission adopts PJM’s proposal on federal subsidies, it should only apply to federal programs adopted after the Commission’s Order.


84 *Id.* at 11.

85 *Id.* at 2.
or benefit they value. As a private, wholly non-FERC jurisdictional transaction, there is no basis for the Commission to insert its judgment as to whether or not the terms of that transaction are reasonable. These are payments for co-products of electricity whose value has been determined in private, arms-length transaction. To the extent the Commission treats this private transaction as “uneconomic” out-of-market support that must be mitigated (i.e., deprive the resource of the benefit of the private transaction), the Commission is regulating the terms of the sale of a non-jurisdictional product and grossly oversteps its role under the Federal Power Act.\textsuperscript{86} While the Federal Power Act authorizes the Commission to regulate wholesale electricity rates and any rule or practice “affecting” such rates, there are clear limits on the Commission’s authority to regulate practices affecting rates. “[I]f indirect or tangential impacts on wholesale electricity rates sufficed, FERC could regulate now in one industry, now in another, changing a vast array of rules and practices to implement its vision of reasonableness and justice.”\textsuperscript{87} Although the resource receiving the voluntary REC may seek to participate in the wholesale capacity market, this is too tenuous a link to allow the Commission to overturn the terms of the private, contractual arrangement with the voluntary REC purchaser, marketer, or broker.

**CONCLUSION**

Clean Energy Advocates respectfully submit these comments for the Commission’s consideration regarding the scope of an expanded MOPR.

\textsuperscript{86} As described in section I, Clean Energy Advocates consider this to be the case when the Commission second-guesses state determinations regarding the value of environmental services or benefits as well.

\textsuperscript{87} *FERC v. Elec. Power Supply Ass’n*, 136 S. Ct. 760, 774 (2016) (“We cannot imagine that was what Congress had in mind.”).
Respectfully submitted,

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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.

Dated at New York, NY this 2nd of October, 2018.

/s/ Miles Farmer
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Exhibit E
Comments of Clean Energy and Consumer Advocates, October 2, 2018
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
COMMENTS OF CLEAN ENERGY AND CONSUMER ADVOCATES


The Order held that existing capacity market tariff provisions are not just and reasonable, rejected the PJM Interconnection, LLC (“PJM”) proposed tariff revisions as not just and reasonable, and instituted further proceedings to determine a replacement capacity market rate.

These comments address the design of the Commission’s proposed resource-specific Fixed Resource Requirement Alternative as well as a transition mechanism, but not the scope of the minimum offer price rule or how it should be implemented. The undersigned organizations have submitted separate comments on some or all of those issues.

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Attachment B: Shared Principles for Designing FRR-RS

Attachment C: Affidavit of James F. Wilson
I. Summary of Argument

These comments describe the elements of a resource-specific fixed resource requirement (FRR) construct that is flexible enough to be useful under a wide range of state regulatory scenarios and aims for administrative workability, while ensuring resource adequacy and accurate Reliability Pricing Model (“RPM”) price signals. A proposal for the resource-specific FRR consistent with the principles set out in these comments and a supporting declaration of economist James F. Wilson, is attached to these comments.

Clean Energy Advocates and Consumer Advocates, respectively, address the scope of the minimum offer price rule (“MOPR”) in separate comments. Imposition of an expanded MOPR to capacity resources that receive out-of-market revenues as a result of state clean energy policies could potentially force PJM customers to pay far more for capacity resources than necessary and worsen the over-procurement situation in PJM. While our organizations maintain that state policies that correct for market failure by compensating generators for environmental benefits do not lead to wholesale capacity prices that are unjust and unreasonable, we strongly agree with the Commission’s suggestion that an expanded MOPR, if implemented, must be accompanied by a pathway to recognize the value of capacity resources incentivized by state policy to avoid unnecessary burdens on consumers and states’ ability to pursue valid policy goals.

For the resource-specific FRR to be workable from the perspective of states, load-serving entities, and eligible capacity resources, there must be flexibility in how the load to be removed from RPM is identified. Because capacity assignments between load and capacity resources will take time to arrange, particularly given states’ interest in ensuring that such arrangements are beneficial to retail customers, it is important that capacity resources have ample time between when their eligibility for the resource-specific FRR is determined and their deadline for electing
this option for assigning their capacity. Finally, load-serving entities that choose to purchase capacity through the resource-specific FRR should not be effectively required to purchase more capacity than they would if procuring through RPM.

It is equally important that under the bifurcated capacity market construct, RPM sends accurate price signals regarding the need for capacity investment to serve the load that does not obtain capacity through the resource-specific FRR. We endorse the Commission’s proposed structure of completely removing resource-specific FRR capacity and commensurate load from the auction, which will assist in promoting transparency and preserving the integrity of RPM. In addition, the resource-specific FRR should be designed to maintain locational price signals, and adapt under circumstances where market power problems would arise from a significantly diminished portion of load served through RPM in any particular zone. We urge the Commission to reject schemes to further inflate RPM clearing prices or make gratuitous payments to resources that do not clear under the faulty premise that an RPM without any participation by state-incentivized resources is somehow still unable to set adequate clearing prices through the fundamental mechanics of supply and demand.

Finally, the Commission should adopt a transition mechanism to avoid full implementation of the MOPR before legal frameworks can be established at the state level to ensure the workability of a resource-specific FRR option. The Commission has previously allowed for new rules to be phased-in where doing so would give market participants and the market operator a chance to adapt to new rules and to avoid the rate shock and inaccurate price signals that might result from an artificially imposed short-term shortage of capacity. States have already expressed their concern to FERC about adapting their laws to the new framework, and the full scope of the changes potentially needed at the state level cannot even be understood until
the final rules are in place. The Commission should, at a minimum, allow for states to seek a one-year delay in the implementation of the expanded MOPR where a state has not yet been able to implement changes needed to its statutory or regulatory framework to utilize the resource-specific FRR, despite good faith efforts to do so.

II. Background

On March 21, 2016, several generation owners filed a complaint pursuant to Section 206 of the Federal Power Act ("FPA"), requesting that PJM be required to revise its RPM rules in order to address allegedly “below-cost offers” submitted by resources “whose continued operation is being subsidized by State-approved out-of-market payments.” On April 9, 2018, PJM submitted a Section 205 filing asserting that its current RPM rules were not just and reasonable due to the effects of out-of-market payments resulting from state policies and proposing two alternative revisions to the RPM to correct for the perceived problems.

On June 29, the Commission issued an order addressing both the March 2016 Section 206 proceeding and PJM’s Section 205. Based on the combined records in these proceedings, the Commission found PJM’s existing Tariff to be unjust and unreasonable because it did not limit

1 16 U.S.C. § 824e.
2 Complaint of Calpine Corp. et al., Docket No. EL16-49-000 at 2 (Mar. 31, 2016); see also Amended Complaint of Calpine Corp. et al., Docket No. EL16-49-000 at 10-11 (Jan. 9, 2017) (amending complaint to include Illinois’ zero emission credit program as an example of purportedly price suppressive state policies).
3 16 U.S.C. § 824d.
4 Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000 (Apr. 9, 2018) (“PJM Filing”).
price suppression caused by out-of-market payments to certain resources under state policies.\textsuperscript{5} However, the Commission rejected both of PJM’s proposed revisions to the RPM, as well as the revisions proposed in the Section 206 filing, as unjust and unreasonable and unduly discriminatory.\textsuperscript{6} Finding the record inadequate to determine a just and reasonable replacement rate, the Commission instituted a paper hearing with an opportunity for initial and reply comments, with an order expected in time for implementation prior to the base residual auction to be held in 2019.\textsuperscript{7}

In the June 29 Order, the Commission described in general terms a two-part replacement rate that it preliminarily believes would be just and reasonable and not unduly discriminatory. The first component of this replacement rate would be an extension of the minimum offer price rule (“MOPR”) to all resources, new or existing, that receive out of market payments.\textsuperscript{8} The Commission did not define “out of market payments,” and in fact the scope of the extended MOPR is a key question for this paper hearing. The Commission did, however, refer to zero emission credit (“ZEC”) programs in Illinois and New Jersey that support existing nuclear generators, state renewable portfolio standard (“RPS”) programs that provide renewable resources with revenue through the sale of renewable energy credits (“RECs”), and offshore wind procurement programs in Maryland and New Jersey.\textsuperscript{9} Second, recognizing that the extended MOPR would create the potential for “double payment and over procurement” and

\textsuperscript{5} Order at P 150.

\textsuperscript{6} Id. at PP 63, 105.

\textsuperscript{7} Id. at P 149.

\textsuperscript{8} Id. at P 158.

\textsuperscript{9} Id. at P 1, n.1; id. at P 151.
affect “states’ right to pursue valid policy goals”, the Commission suggested that the MOPR should be accompanied by a resource-specific fixed resource requirement (“FRR”) construct through which generation subject to the MOPR and a corresponding amount of load would exit the RPM.\textsuperscript{10} This would lead, in the Commission’s words, to a bifurcated capacity market construct.\textsuperscript{11}

The Commission requested comment on the design of both the expanded MOPR and the resource-specific FRR as part of the paper hearing.\textsuperscript{12} With respect to the latter, the Commission indicated that it intended the resource-specific FRR to track the existing FRR in basic form, namely that “[r]esources and load that take advantage of this new resource-specific FRR Alternative would not participate in the PJM capacity market, and would neither make nor receive payments from that capacity market.”\textsuperscript{13} The Commission stated that a bifurcated structure of this type would improve the integrity of the capacity auction, increase transparency for consumers regarding the impact of state programs on capacity prices, and limit the impacts of one state’s policy on others.\textsuperscript{14}

\textsuperscript{10} \textit{Id.} at PP 159-60.
\textsuperscript{11} \textit{Id.} at P 161. We note that the market would actually have three parts, with the inclusion of the existing FRR Alternative.
\textsuperscript{12} \textit{Id.} at PP 164-169.
\textsuperscript{13} \textit{Id.} at P 160.
\textsuperscript{14} \textit{Id.} at PP 161-62.
III. Resource-Specific Fixed Resource Requirement

In its PJM Capacity Market Order, the Commission “recognize[d] that, if PJM’s MOPR applies to state subsidized resources with few or no exceptions, and yet the states continue to support those resources, some ratepayers may be obligated to pay for capacity both through the state programs providing out-of-market support and through the capacity market.”\textsuperscript{15} Accordingly, it proposed “that PJM adapt its current FRR option to allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load.”\textsuperscript{16}

While in our view any approach that applies the MOPR to resources based on the receipt of out-of-market revenues is unjust and unreasonable, we agree that implementing a resource-specific FRR mechanism as outlined by the Commission may help “avoid the potential for double payment and over procurement.”\textsuperscript{17} As the Commission has previously recognized, excess capacity is a “significant undesirable effect[ ]” that can render a tariff unjust and unreasonable.\textsuperscript{18}

However, for customers to be spared the costs of over-procurement and for legitimate state policies to be respected, the resource specific FRR must allow for flexible implementation so that it can be readily used in practice. To the extent that the resource-specific FRR is nominally available but not able to account for state-supported resources in practice, customers

\textsuperscript{15} Id. at P 159.

\textsuperscript{16} Id. at P 160.

\textsuperscript{17} Id.

\textsuperscript{18} PJM Interconnection, L.L.C., 147 FERC ¶ 61,108 at P 68 (2014) (“PJM’s proposed OATT and RAA revisions have significant undesirable effects such as increasing the risk for capacity market sellers, creating undue barriers to entry, limiting opportunity for beneficial trade, and unnecessarily raising the cost of capacity through the acquisition of excess capacity.”) (emphasis added).
will be overcharged for capacity and states’ ability to set energy policy will be frustrated. While we agree that the existing FRR Alternative is a useful starting point for structuring a resource-specific FRR, the existing FRR offers a cautionary tale for the Commission about designing an overly restrictive or inflexible out-of-auction construct. Due to its restrictive terms, the existing FRR Alternative has been very difficult for load-serving entities to utilize. The stakes of an unworkable resource-specific FRR would be much higher, as it would lead to the overprocurement and double payment problems the Commission seeks to avoid.

Attached to these comments is a proposal to implement the Commission’s proposed resource-specific FRR Alternative in a straightforward and workable manner. Our proposal refers to this mechanism as the Fixed Resource Requirement-Resource Specific, or “FRR-RS”, an acronym used below. This proposal is based on a concept for the FRR-RS initially developed by economists James Wilson and Rob Gramlich in response to PJM’s request for stakeholder input. This proposal has undergone subsequent revisions as a result of conversations with a wide range of stakeholders including state representatives, consumer advocates, generators, and load-serving entities. This proposal is consistent with the Shared Principles for a Resource-Specific Fixed Resource Requirement adopted by Sierra Club, Natural Resources Defense


Council, Citizens Utility Board of Illinois, Office of the People’s Counsel for the District of Columbia, Exelon Corporation, Talen Energy, Public Service Electric and Gas Company, and the Nuclear Energy Institute.\textsuperscript{22} We endorse those principles, which we believe are fundamental to an effective FRR-RS that will avoid the worst impacts of unmitigated application of the minimum offer price rule to state-supported resources.

The first section below describes several key elements of an FRR-RS that we believe is workable for states, load-serving entities, and eligible capacity resource. Next, we explain why RPM will continue to be competitive and send adequate price signals for capacity investment as part of a bifurcated capacity market structure. We highlight FRR-RS design elements that are important for maintaining a competitive RPM. Finally, we propose a specific transition mechanism to avoid instability in PJM’s capacity market and protect consumers as the region shifts to a substantially different construct for procuring capacity.

\textbf{A. To prevent unnecessary costs to customers, FRR-RS must be as workable as possible, and must not contain unjustified restrictions on FRR-RS arrangements.}

In this section, we highlight several key issues for designing a workable FRR-RS, focusing in particular on many of the issues on which the Commission specifically requested comment.\textsuperscript{23}

\begin{itemize}
  \item These shared principles are included as Attachment B to this filing.
  \item Order at PP 166-70.
\end{itemize}
1. **FRR-RS Capacity Resources should have flexibility in identifying commensurate load.**

   One question the Commission acknowledges regarding its proposed resource-specific FRR is “[h]ow to identify the load that will be removed from the PJM capacity market auction in connection with resource owners choosing the resource-specific FRR Alternative.”

   Our proposal calls for the capacity resource, when electing FRR-RS, to identify to PJM the associated commensurate load. In other words, identification of the associated load should be up to the FRR-RS capacity resource, subject to oversight by state regulators or state energy procurement agencies that may opt for a more active role to ensure that identification of the associated load is consistent with state law. This would create a default structure that allows a resource to bilaterally contract with load serving entities to sell capacity (which may be implemented to some extent absent any new state regulation). At the same time, it recognizes that such a default structure may be appropriately overridden by state regulation to account for the unique features of each state’s policy mix and system of retail rate regulation.

   This flexible structure, which allows states to shape FRR-RS use in a manner that efficiently accommodates their own policies, reflects our view that there is no one right way for such load to be identified, but instead that multiple pathways for the association of load and FRR-RS capacity resources should be allowed in order for those capacity resources or states whose policies are implicated to have the flexibility needed to adapt to this significant change in market structure. The Commission should avoid imposing a single structure by which load and FRR-RS resources must be matched, regardless of state regulation. It should also avoid placing

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24 *Id.* at P 166.

25 Attachment A at ¶5.
any limits on how load is matched with FRR-RS capacity where such limits are not required in order to ensure resource adequacy. The only limit we believe is appropriate regarding which load can be associated with an FRR-RS resource is that locational constraints in the PJM system must be respected, as discussed in Section III.B.2, below.

Our flexible structure will allow states and resources to determine how to match with load based on the regulatory context. For example, some resources will be eligible for FRR-RS because they were selected through a competitive procurement process overseen by a state agency that procures the resource on behalf of most or all load in the state. In such cases, state agencies may want to take an active role in determining how those resources are paid for their capacity, and are likely to be in a position where they can determine which load-serving entities in the state should be relieved of obligations to purchase RPM capacity and in what amounts. Other FRR-RS eligible capacity resources will be subject to the MOPR based on an existing unbundled bilateral contract with a load-serving entity through which the capacity resource is paid for its environmental benefits (e.g., REC payments). For these capacity resources, it may be the most straightforward to negotiate compensation for their capacity value via a capacity contract with the LSE with which they have an existing REC contract.26 Yet another example is a renewable energy capacity resource that is subject to the MOPR due to revenues it receives for its RECs from a corporate purchaser, or multiple such purchasers, that do not arise from a state

26 In some circumstances, as described below, certain assignments of capacity under a resource-specific FRR could be prevented by capacity import limits. For this reason, the Commission should not require the associated load to be the same load that purchased RECs or ZECs from an FRR-RS capacity resource. Requiring such bundled transactions risks stranding valuable capacity resources that might otherwise be able to offer capacity to a more local load-serving entity.
policy but instead from voluntary company policies to favor the use of clean energy. Capacity resources in these circumstances may instead seek to sell capacity outside the auction to any willing LSE partner, who might be attracted to the possibility of purchasing lower cost or lower-cost-risk capacity.

These examples are not meant to comprehensively describe the different scenarios giving rise to out-of-market revenues that would trigger the MOPR under the Order; creating such a comprehensive list and specifying how the load is to be identified in each case would be futile. Instead, we urge the Commission to adopt an all-of-the-above approach to identification of associated load.

One approach the Commission should avoid is to simply assign load to FRR-RS resources on a proportional basis. That approach would not match several types of potential state policies (as described above), and would have the further drawback that in many cases it could effectively prevent FRR-RS resources from receiving any compensation for their capacity value. If load-serving entities are assured of receiving credit for the capacity value of FRR-RS resources whether or not they enter into contracts with FRR-RS resources, they will have little

27 As described in the separately filed comments of Clean Energy Advocates regarding the scope of the MOPR, the corporate renewable procurement market is large and growing.

28 Based on presentations to stakeholders, we understand that PJM plans to identify the commensurate load through a single mechanism within PJM’s control, specifically by simply allocating revenues not paid to FRR-RS resources pro rata across the load in the state subsidizing the resource. This mechanism wrongly assumes that there will be a single state’s policy, or any state’s policy, responsible for the out-of-market revenues that trigger the MOPR. It also could make it difficult for FRR-RS entities to obtain compensation for their capacity from this dispersed load, as explained below.

29 As explained below, our proposal calls for expressing both the load and capacity involved in FRR-RS arrangements in terms of unforced capacity value, or “UCAP.”
incentive to compensate FRR-RS resources for their capacity, potentially preventing compensation for capacity sales from being determined through a competitive process.

In sum, because capacity resources may be subject to the MOPR based on a wide array of out-of-market revenue types and therefore have widely divergent circumstances, a single mechanism for pairing these resources with load is unlikely to be workable in all cases.

2. Load seeking to procure capacity through FRR-RS arrangements should not face unjustified reserve requirement obligations.

Another key question posed by the Commission is how to “accommodate required reserves for the load pulled from the PJM capacity market.” As described in the attached affidavit of James Wilson, and incorporated into our proposal, the Commission should adopt the approach used in the existing FRR Alternative, which defines the load removed from the auction in terms of Unforced Capacity obligation. Under the existing FRR Alternative, the Unforced Capacity obligation is defined as the peak load of the LSE electing the FRR times the “Forecast Pool Requirement,” which is a factor that represents the margin of UCAP over peak load needed for resource adequacy and is derived from the Installed Reserve Margin (IRM). Once the load is defined in UCAP terms, it can be paired with capacity defined in UCAP terms on a one to one basis. Such an arrangement appropriately accounts for required reserves because

30 Order at P 169.
31 Attachment C at Section V.A.
32 Attachment A at ¶¶9-10.
33 RAA Schedule 8.1, Section B.1 (“A Party is eligible to select the FRR Alternative if it . . . (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area.”).
34 RAA Schedule 8.1, Section F.1. The calculation also includes an adjustment based on the “Final Zonal FRR Scaling Factor.”
the total amount of capacity supplied to the system (through RPM, FRR, and FRR-RS arrangements) will equal the amount of UCAP necessary to meet the IRM. Some parties have suggested that the reserves associated with the load removed from the auction in association with FRR-RS should be larger than that required by the IRM simply because RPM tends to clear an amount of capacity well in excess of the IRM. That RPM regularly clears an excessive amount of capacity does not change the principles underlying PJM’s establishment of the IRM as the optimal amount of capacity for the region. The possibility of exceeding the IRM in the base residual auction exists because RPM employs a downward sloping demand curve, in part to reduce market volatility. Where this consideration is absent, as in FRR-RS, to force load to procure excess capacity merely because RPM has cleared above the IRM would be unjust and unreasonable. Furthermore, as explained in the attached affidavit of James Wilson, when RPM clears an amount of capacity in excess of the IRM, it actually pays less, so there is no fairness issue with not imposing a similarly inflated capacity procurement requirement on FRR-RS load.\(^{35}\)

Finally, we note that matching FRR-RS capacity and load based on UCAP also accounts for the forced outage rate of the capacity resource. UCAP is the “MW value of a capacity resource in the PJM Capacity Market,” and represents the availability of the unit after accounting for its EFORd (forced outage rate).\(^{36}\) Because UCAP is also the currency for capacity resources in RPM, it is an appropriate measure of the capacity value of FRR-RS capacity resources, given

\(^{35}\) Attachment C, Wilson Affidavit at ¶28.

\(^{36}\) As explained in PJM’s online glossary of terms, “For generating unit, the unforced capacity value is equal to installed capacity of unit multiplied by (1 – unit’s EFORd).” See https://www.pjm.com/Glossary.aspx# (last visited Oct. 1, 2018).
that such resources would continue to be subject to Capacity Performance requirements and to participate in the energy and ancillary services markets.\textsuperscript{37}

3. **Eligibility for FRR-RS must be clearly defined and RPM timelines must allow for FRR-RS arrangements to be made.**

Any resource that is subject to the MOPR due to the receipt of out-of-market revenues should be eligible to elect FRR-RS. Otherwise the FRR-RS will not function to offer a pathway for state-supported resources to offer their capacity in PJM, worsening over-procurement and undermining state policies. This basic principle leads to two additional concepts that we believe are essential to a workable FRR-RS.

First, the scope of FRR-RS eligibility (to the extent that it is not co-extensive with application of the MOPR), must be clearly set out by the Commission and should remain as stable as possible. Clarity and stability is necessary for states developing clean procurement statutes or regulations to account for the likely market opportunities for sales of capacity from the resources they procure. Clean energy resource developers must also be able to accurately plan projects, for which an understanding of whether or not a resource will be subject to a MOPR or instead eligible to participate in FRR-RS is necessary.

\textsuperscript{37} Order at P 160. In a letter to members, states, and interested stakeholders, shortly after the Commission’s June 29 order, PJM asserted that “[a]n ‘appropriate corresponding quantity of load’ must account for reserves and for any other risks inherent to a unit-specific bilateral (including the loss of the portfolio benefit derived from RPM’s larger centralized resource procurement).” See https://www.pjm.com/-/media/committees-groups/committees/mrc/20180802-special/20180802-pjm-comments-on-commission-order-on-mopr-unit-specific-frr.ashx (last visited Oct. 1, 2018). PJM’s assertion that there is a loss of portfolio benefit associated with FRR-RS arrangements is simply incorrect—FRR-RS capacity resources would continue to be dispatched by PJM just like RPM resources and function as part of the region’s capacity portfolio regardless of whether their compensation for their capacity value comes through a bilateral arrangement or a centralized procurement process.
Second, in the months leading up to any given base residual auction, capacity resources would need a final determination regarding the application of the MOPR, any exemptions, and the offer price floor well in advance of the deadline to elect FRR-RS. A capacity resource should have at least two months from the time it knows whether and how the MOPR will apply to it in which to negotiate an arrangement to assign capacity to an LSE or to notify the relevant state procurement office or regulator of their eligibility for FRR-RS in cases where a state entity is actively engaged in identifying commensurate load. Shortcutting that process will lead to capacity resources being unable to negotiate FRR-RS arrangements and thereby result in capacity from those resources being excluded from the bifurcated market construct, worsening over-procurement in PJM.

A lack of clarity in FRR-RS eligibility (either with regard to the general program rules or with regard to the determinations made about a specific resources in the months leading up to the auction) could result in capacity resources being unable to plan for FRR-RS participation or obtain financing for development.

While many of the current deadlines for MOPR-related determinations occur in the last few months before the BRA, such a timeline will not work with a fundamental redesign of the capacity market along the lines proposed by the Commission. Whereas the MOPR previously applied only to a narrow set of resources, it will now extend to a broad swath of resources within

38 We have proposed that resources must elect FRR-RS by four months prior to the BRA, consistent with the current deadline for FRR Alternative plans. Attachment A at ¶5. That election deadline allows PJM time to incorporate the FRR, and now FRR-RS elections into its planning parameters that are published February 1 of each year.
PJM, including those for which there is no precedent for establishing an offer price floor. Moreover, whereas in prior auctions, once a resource triggered the MOPR it had no choice but to offer into RPM at the assigned offer price floor, application of the MOPR would now give resources an opportunity to elect FRR-RS. In light of these fundamental changes to PJM’s market, changes to the timeline for MOPR determination are warranted.

B. A bifurcated capacity market structure will provide the correct level of incentive for capacity investment in PJM.

1. Adequate RPM prices will be maintained in a bifurcated capacity market structure.

In a bifurcated capacity market structure, RPM must continue to send the proper price signals needed for resource adequacy in PJM. In practice, this means that RPM needs to procure only enough capacity to match the load not served under FRR plans or FRR-RS arrangements.\(^{39}\) The adequacy of RPM price signals must be assessed in light of that objective, not with reference to prices in earlier auctions.\(^{40}\) To the extent that clearing prices are lower in the auction portion of the bifurcated market structure than they were prior to implementation (which, aside from mere conjecture, has yet to be demonstrated), this is not an indicator that prices are lower than

\(^{39}\) This is likely to still be the significant majority of load in PJM, depending on the ultimate scope of the MOPR selected by the Commission.

\(^{40}\) For example, the PJM Independent Market Monitor has produced an analysis of the potential impacts of the resource-specific FRR on RPM clearing prices and finds that they are significantly lower under most scenarios. The IMM concludes from these data that there is “no safe level” of resources specific FRR, suggesting a regulatory judgment based solely on the incomplete picture presented by this type of static analysis. The IMM does not examine whether lower prices are sufficient to incent adequate resources to match capacity needs not served by FRR-RS. See Monitoring Analytics, MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction (Sept. 26, 2018), at p. 2, available at http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf.
where they should be. Proponents of an argument that the FRR-RS would “suppress” market prices in a pejorative sense bear the burden of articulating a rationale for why these prices are too low; any assertion that prices will be lower is merely a predictive observation, not evidence of rates that are not just and reasonable.  

We believe that the most straightforward way to signal to RPM sellers how much demand exists for their capacity is to handle FRR-RS resources and load in the same way that FRR resources and load are currently handled—outside of the auction. Our proposal envisions that resources that are subject to the MOPR as a result of actionable out-of-market revenues will not be offered into the auction, and the commensurate load associated with those resources will be removed from the RPM reliability requirement and consequently, from the variable resource requirement curve. Thus, prices in RPM would be based solely on the offers of resources not receiving out-of-market revenues, cleared against a VRR curve that reflects only the load that needs to procure capacity through the auction. The clearing price generated through such an

41 The Commission has previously found tariff revisions to be unjust and unreasonable to the extent that they would “result in higher clearing prices than if [otherwise competitive] resources had participated” in a capacity auction. PJM Interconnection, L.L.C., 161 FERC ¶ 61,252 at P 43 (2017).

42 In this way, our proposal departs from what we believe PJM to be proposing, which would clear both FRR-RS resources and load through its auction process, but pay the former nothing for the capacity commitment they incur, and refund the latter based on the value of payments not made to the associated FRR-RS capacity resource. https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx.

43 Clean Energy and Consumer Advocates maintain that the current market design also provides the correct price signals, in that any price reductions that may result from offers reflecting out-of-market revenue, reflect the reduced need for capacity in light of state policies incenting certain categories of capacity resources. See generally Clean Energy Advocates’ Petition for Rehearing in Docket Nos. ER18-1314; EL16-49.
auction configuration would be immune from charges that it is suppressed by the offers of resources with out-of-market revenues. Handling such resources outside of the auction would also provide the transparency benefits envisioned by the Commission when recommending the development of FRR-RS. That said, we believe that either in- or out-of-auction clearing could be designed to workably achieve the Commission’s goals. In-auction clearing may offer certain administrative advantages to both the load and capacity participants that should be considered.

Projections of significantly different capacity market clearing prices as a result of FRR-RS should be viewed skeptically because they ignore the dynamic nature of the market. As economist James Wilson explains, these projections are static in that they “typically add[] or remove[] one or a few resources from the supply curves while holding everything else constant, [and] tend[] to show large impacts of small changes to supply, demand, or rules, including MOPR rules.” The static model ignores the real-world reactions by other market participants, who adapt their plans and market offers to reflect changing regulatory and market circumstances. The dynamic nature of RPM is borne out by the observation that despite very large amounts of entry and exit, and year-to-year variation in prices, RPM prices tend to return to an equilibrium of around $100/MW-day. RPM will adapt to the introduction of FRR-RS as it has to other major market changes in recent years, though any short-term fluctuations in prices can be minimized by the Commission providing plenty of time for market participants to

44 Order at P 162.
45 Attachment C, Wilson Affidavit at ¶39.
46 Id. at ¶40.
47 Id. at ¶¶41-43.
understand the new rules and prepare—further reason for the Commission to consider a transition mechanism as described in Part IV, below.

Others have suggested that a bifurcated capacity market will allow states to offer out-of-market revenues to additional resources, potentially leading to a merely residual capacity market in PJM, as some allege.\(^\text{48}\) This charge neglects the cost of state programs. The empirical evidence has demonstrated that such an indiscriminate “spread of subsidies” has not occurred under the status quo market rules. The theory of snowballing state subsidies also ignores that the transaction costs associated with making FRR-RS arrangements may be substantial in some cases due to the need to enact state legislation or develop regulations, negotiate capacity payments outside the auction, and potentially defend the level of these payments, which would be subject to the Commission’s jurisdiction. The notion that states would incur both externality costs and these transaction costs simply because by doing so they could ensure that a resource would obtain a capacity commitment is baseless. Moreover, to the extent that states have adopted the policies focused on by the Commission’s Order, it is largely due to regulatory goals well within state authority, and it is not the Commission’s role to discourage the pursuit of those goals. State climate policies, the policies for which the Commission has thus far focused its concern, are designed to achieve environmental regulatory objectives.\(^\text{49}\) Having decided that the best course of action to facilitate the continued pursuit of such goals is to allow for state-

\(^\text{48}\) See, e.g., Letter from Calpine Corporation to the Commission at 1, Re Calpine Corporation, et al., v. PJM Interconnection, L.L.C., Docket No. EL16-49-000; PJM Interconnection, L.L.C., Docket No. ER18-1314-000.; PJM Interconnection, L.L.C., Docket No. EL18-178-000 (consolidated) (filed July 10, 2018) (noting concerns about RPM becoming a “purely residual capacity market”) (emphasis omitted).

\(^\text{49}\) See Protest of Clean Energy Advocates, Docket No. ER18-1314, at Background Section I.
supported capacity to be removed from RPM through FRR-RS arrangements, the Commission should not fear that states will take advantage of that arrangement. Rather, giving them the option of doing so is precisely the point of establishing FRR-RS. The suggested alternative of forcing customers to support a particular mix of resources through RPM that is insulated from state policies would violate the “dual regulatory system” established by the Federal Power Act.\footnote{Coalition for Competitive Electricity v. Zibelman, No. 17-2654, slip op. at 22 (2d Cir. Sept. 27, 2018).}

2. FRR-RS design should include elements to preserve RPM integrity.

The Commission has asked whether there are “scenarios in which the FRR Alternative could affect the competitiveness of the capacity market clearing prices.”\footnote{Order at P 170.} RPM will continue to send adequate price signals so long as the FRR-RS mechanism adheres to a few basic principles. One important element of FRR-RS design, reflected in the attached proposal, is that it respects capacity import limits and thereby preserves the locational price signals in RPM. We have proposed that FRR-RS arrangements may not exceed an LSE’s share of Capacity Emergency Transfer Limits (“CETL”) for any transmission-constrained zone.\footnote{Or, in the case where a state is handling FRR-RS procurement on behalf of LSEs and competitive suppliers, it must respect the aggregate import capacity available to those entities.} An LSE may choose to use up to 100% of its CETL for FRR-RS arrangements, procuring the necessary internal portion of its capacity requirement through RPM. In this way, the LSE’s overall reliability requirement will conform to the Percentage of Internal Resources Requirement. By structuring the bifurcated
capacity market to reflect locational restrictions, prices in different modeled LDAs will continue to reflect the relative scarcity of capacity in that location.\(^{53}\)

Hypothetically, it is also possible that RPM market conditions could become uncompetitive if a large portion of the capacity resources in a zone were subjected to the MOPR and elected FRR-RS, resulting in a small amount of load and capacity still participating in RPM. Under this unlikely scenario, it would be appropriate to address these situations by allowing all capacity resources in such a zone to elect FRR-RS, thus having all load in the zone served through either FRR or FRR-RS arrangements.\(^ {54}\) Economist James Wilson proposes that this alternative approach be triggered where the remaining RPM UCAP load is less than ten percent of the modeled zone’s total reliability requirement, or less than 2,000 MW.\(^ {55}\) This is far preferable to a cap on FRR-RS election (as others have proposed), because it addresses the market power issues that might arise in a zone with significantly reduced load without creating a new double payment or over-procurement problem (as a cap would create).

One design feature that is not necessary to ensure RPM continues to deliver adequate price signals is a requirement that a resource electing FRR-RS must continue to elect FRR-RS for a minimum duration of time.\(^ {56}\) While such requirements have been suggested as a mechanism

\(^{53}\) This structure also means that states or LSEs may be restricted from procuring as much FRR-RS capacity as they would prefer, which makes it critical that capacity resources eligible for FRR-RS be allowed to associate with any load, regardless of whether that load has also purchased RECs or similar attributes from the capacity resource. To do otherwise runs the risk of stranding capacity, at potentially significant cost to consumers.

\(^{54}\) Attachment C, Wilson Affidavit at ¶36.

\(^{55}\) \textit{Id.}

\(^{56}\) Order at P 168 ("Another issue is the length of time resources receiving out-of-market support who chose the resource-specific FRR Alternative must remain outside of the PJM
to prevent a resource from evading the MOPR, such concerns can be addressed more narrowly by calculating the offer floor under the MOPR for an FRR-RS resource entering RPM for the first time as though the resource were a new resource.\textsuperscript{57}

While the existing FRR Alternative does have a minimum duration requirement, that requirement was adopted as part of the original compromises giving rise to RPM almost two decades ago and was not necessary in order to maintain the integrity of RPM.\textsuperscript{58} Indeed, the current FRR structure \textit{allows} for individual resources to shift between FRR and RPM. Within the required five-year minimum duration period for FRR plans, the EDC may change out the capacity resources that are part of its FRR portfolio.\textsuperscript{59}

Furthermore, the large, existing FRR-RS eligible resources that could potentially affect RPM prices by switching are already practically restricted in their ability to return to RPM due to the application of the MOPR, making it extremely unlikely that they would clear RPM.\textsuperscript{60} As a result, FRR-RS eligible resources are unlikely to strategically switch between FRR-RS and RPM. The only exception to this beyond new resources seeking to avert the MOPR being applied in the year they first enter the market (which can be addressed through a more narrow measure, capacity market auction and the mechanism by which such resources can return to the auction.”).  

\textsuperscript{57} Attachment C, Wilson Affidavit at ¶33.  
\textsuperscript{58} \textit{PJM Interconnect L.L.C.}, 117 FERC ¶ 61,331 at PP 21-23 (2006). When it approved the RPM settlement, the Commission only made findings regarding the portions of the settlement that were contested, which did not include the FRR design features. \textit{Id.} at P 58. As such, these features have not been the subject of close scrutiny by the Commission. \textit{Id.} at P 113.  
\textsuperscript{59} PJM Reliability Assurance Agreement, Schedule 8.1, Section D.1.  
\textsuperscript{60} Attachment C, Wilson Affidavit at ¶31.
as discussed above), is that an FRR-RS resource might consider returning to RPM if it appeared there could be a capacity shortage in its zone, portending an RPM price spike.  

But this case only serves to demonstrate the benefits of having no minimum FRR-RS stay. In such a circumstance, if the FRR-RS resource and its commensurate load were to return to RPM, and if the resource were to clear at its Reference Price, that would likely prevent an even higher price spike.  

Return of FRR-RS resources to RPM should not be discouraged in such circumstances.

3. Any proposal for an alternative clearing price mechanism is unjustified.

In implementing FRR-RS, the Federal Power Act dictates that Commission should avoid imposing any structure that inflates RPM prices beyond the amount necessary to ensure adequate reserves.

Based on discussions among stakeholders in the last several months and materials shared by PJM, we understand that PJM is proposing a 2-stage auction mechanism related to its capacity repricing proposal that the Commission rejected in June. PJM has stated that it would implement what it calls the “resource carve out” by having all resources that elect the carve out offer into the auction at a price of zero. This first stage of the auction would determine which resources obtain capacity obligations. PJM would then remove all the “carved out” resources from the supply stack and re-run the auction with the same demand curve; this second stage would determine the clearing price to be paid to all resources that cleared in the first stage. We

61  Id. at ¶32.
62 Id.
63 https://www.pjm.com/-/media/committees-groups/committees/mrc/20180911-special/20180911-pjm-proposal-including-stakeholder-input.ashx. To the extent that any details of PJM’s proposal to the Commission as filed on October 2 differ from our understanding of the RTO’s proposed plans, we will address them in our reply comments.
understand that PJM intends to propose yet another component – a so-called “lost opportunity cost” payment to resources that would have cleared the auction but for the carved out resources. We discuss this lost opportunity cost payment further below.

PJM’s alternative market clearing price proposal, as we understand it from recent PJM statements, possesses many of the same flaws as its rejected repricing proposal. Specifically, it continues to “set[] a clearing price that is disconnected from the price used to determine which resources receive capacity commitments,” and will thereby “send incorrect signals, leading to greater uncertainty with respect to entry and exit decisions.” PJM’s latest repricing proposal would inflate capacity prices beyond the level necessary to incent adequate reserves when accounting for capacity supplied through FRR-RS.

PJM also proposes to offer what it calls a lost opportunity cost to capacity resources that would have cleared but for the carved out resources, i.e., those that cleared in stage two but not stage 1. The amount paid to each of these resources would be the difference between the stage 2 clearing price and the resource’s offer price. This structure would reward resources that do not clear in the auction with profits as though they had, paying them despite the fact that the resources would neither incur a capacity obligation nor provide any capacity to PJM customers. These payments would not correspond to any “lost opportunity cost,” in the economic meaning of that term, since the resources receiving these payments did not forgo any opportunities in order to bid into RPM. There is no justification for forcing customers to make such a payment.

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64 Order at P 64.
65 Attachment C, Wilson Affidavit at ¶53.
C. The Commission must provide a smooth transition to a bifurcated market.

In proposing the FRR-RS, the Commission sought comment on whether some mechanism might be needed to “facilitate the transition to this new capacity construct,” noting that such mechanisms had been employed in the past where there were significant changes to the market design.\(^{66}\) We strongly agree that a transition mechanism is appropriate here given the extent of the changes proposed for PJM’s tariff. The introduction of a bifurcated capacity market in PJM and the dramatic expansion of the application of the MOPR\(^{67}\) are more significant changes than any since the introduction of RPM. It will take market participants time to understand the new rules, evaluate what options are available to them under state law. Regulators will need time to incorporate changes into their state and local energy policies in a fashion that does not disrupt the market or place the burden of administratively-determined higher costs on consumers.

1. A transition mechanism is needed.

The Commission has approved PJM’s request to delay the BRA auction to August 14-28, 2019,\(^{68}\) which is likely to be only three or four months after final changes to PJM’s tariff are approved. PJM, the Independent Market Monitor, and market participants will not even know the scope of the MOPR or how offer price floors are to be calculated until such an order comes out, much less the mechanics of the FRR-RS mechanism. Only once a resource knows it is subject to

\(^{66}\) Order at P 170.

\(^{67}\) The Commission has not yet defined the scope of the MOPR, the nature of any exemptions, or methodologies for calculating offer price floors for the new resource types subject to the MOPR.

\(^{68}\) *PJM Interconnection, LLC.*, Order Granting Waiver, 164 FERC ¶ 61,153 (Aug. 30, 2018).
the MOPR and evaluates whether it has a chance to clear RPM at the offer price floor, can that resource begin to explore FRR-RS arrangements. In many cases, that resource may need clarification or actual changes to state law or regulation to enable it to obtain payment for its capacity value through FRR-RS.

Many states may need to adopt new rules or statutory authority to allow their load-serving entities or competitive retail suppliers to make use of FRR-RS, or to clarify how state-incentivized resources subject to the MOPR will be compensated for their capacity value. For example, states with retail choice may need to modify the structure or timing of default supply auctions to work with the FRR-RS mechanism. Load-serving entities without recent experience in bilateral capacity contracts may need clarification from state regulators as to how the prudence of such contracts would be assessed as against recent RPM procurement of this service. States that run centralized procurements for clean energy resources may need to modify statutes regarding eligibility for those procurement processes or to clarify how such resources should be compensated for their capacity value. States that wish to direct LSEs to procure capacity from FRR-RS resources may not currently have the necessary regulatory authority over all LSEs. As the Organization of PJM States, Inc., has explained:69

While a FRR Alternative approach may align with certain states’ policies, many states never contemplated procurement of capacity from specific resources under a restructured framework. As such, many states do not currently have, and may not have time to develop, enact and implement, the enabling authority necessary to facilitate selective capacity procurements like those envisioned under the FRR Alternative approach in time for the next PJM Base Residual Auction (BRA).

Since many of our state legislatures are not expected to reconvene until next year, it is uncertain if such authority would be granted in time, if at all.

Until states see the final rule changes, including how commensurate load will be identified, it is impossible to ascertain or concretely explain what changes to state law might be needed. Nevertheless, states have clearly indicated their concern with implementing the significant changes the Commission envisions for PJM.\(^70\)

A period of only a few months is inadequate for state regulators to make any necessary changes or clarifications, much less pursue legislative changes that may be necessary. Implementation of the expanded MOPR before state-incentivized resources can avail themselves of the FRR-RS could lead to serious disruption of RPM, distort short-term prices signals, and cost consumers dearly. Hasty implementation of the MOPR before FRR-RS is ready could easily lead to a situation in which a resource participated and cleared the BRA held in 2018, then became subject to the MOPR but was unable to avail itself of FRR-RS for the BRA held in 2019, and then in 2020 became able to use the FRR-RS due to changes in state law. RPM would experience a significant price spike for the BRA held in 2019, sending an inaccurate signal as to how much additional capacity is needed. PJM might even perceive a false capacity shortfall in certain zones as a result, and consumers would face significant price increases without corresponding benefits. New capacity would not be developed in response to the price signal in 2019 because suppliers would anticipate prices declining again in 2020.

\(^{70}\) See, e.g., OPSI September 26 Letter to PJM Board, supra; Organization of PJM States, Inc. Motion for Extension of Filing Deadline, Docket Nos. EL16-49-000, ER18-1314, and EL18-178-000 (filed July 27, 2018).
The Commission has previously approved of transition mechanisms of various types whenever significant changes are made to market rules, to allow market participants a chance to adapt. For example, in approving ISO-NE’s Pay for Performance capacity market changes, the Commission found that phasing in the “capacity performance payment rate” would “allow suppliers to gain experience with the new market design at reduced risk exposure before the full Capacity Performance Payment Rate goes into effect,” and would “allow ISO-NE to evaluate market participants’ behavior under the new market design and assess whether the phase-in levels and the ultimate Capacity Performance Payment Rate need to be adjusted in response.”\(^71\)

In an earlier case concerning the introduction of price responsive demand (PRD) to PJM’s capacity market, the Commission found that it was reasonable to allow a transition period because “PRD is a new mechanism with which PJM and its market participants will need time to gain experience and the caps ensure that unanticipated results will not significantly jeopardize or affect the system.”\(^72\) The Commission also found that “this transition period will allow PJM to refine and improve the PRD program before the caps are lifted.”\(^73\)

Most recently, the Commission approved a five-year phase-in of PJM’s Capacity Performance framework. PJM contended that this transition period was needed to provide an “opportunity for resources to invest in, and sufficient time to build, improvements necessary to meet the operational and performance requirements expected of Capacity Performance


\(^{72}\) *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,115 at P 39 (May 14, 2012).

\(^{73}\) *Id.*
Resources.” The Commission agreed that a transition period would allow capacity resources to “make gradual improvements and reduce the burdens such improvements may impose,” and would “mitigate the potential for short-term shortage that might result from an immediate requirement of 100 percent Capacity Performance Resources.” Critically, the Commission noted that “[s]uch a short-term shortage could create price volatility that does not provide a useful price signal for investment.”

Many of the factors previously recognized by the Commission as justifying a transition period or phase-in mechanism are present here. The introduction of a bifurcated capacity market structure would be a “new mechanism with which PJM and its market participants will need time to gain experience,” in order to implement expansive and novel MOPR rules, develop state regulatory mechanisms to reflect new capacity procurement opportunities, make changes to the RPM software and oversight mechanisms, among other adaptations. As in the Capacity Performance proceeding, immediate implementation of an expanded MOPR might result in price signals that inaccurately signal shortages when in fact, if states and resources were given more time to adapt by facilitating the usage of FRR-RS, the region’s abundant capacity would be reflected in market prices.

Based on these factors, a replacement rate would not be just and reasonable absent some kind of transition mechanism. That the Commission has already found PJM’s existing rates to be unjust and unreasonable does not justify a rush to implement a replacement rate where hasty

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74 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 at P 214 (June 9, 2015).
75 Id. at P 253.
76 Id.
77 139 FERC ¶ 61,115 at P 39.
implementation would render that replacement rate itself inconsistent with the Federal Power Act.\textsuperscript{78}

2. **The Commission can provide a transition mechanism by providing a limited waiver when a state certifies that it is pursuing an FRR-RS solution.**

As a mechanism to allow for a smooth transition to the bifurcated capacity construct, we propose that for the 2019 Base Residual Auction, a capacity resource that is subject to the MOPR as a result of the MOPR’s expanded scope can obtain a one-year waiver of the application of the MOPR if a state utility regulatory agency certifies to PJM that the state has not yet been able to adopt the necessary legal or regulatory framework for capacity resources to utilize the FRR-RS effectively. Such a certification should explain the state’s ongoing process to adopt the needed state law provisions to enable use of FRR-RS. PJM shall accept such a certification if the state utility regulatory agency asserts in good faith that it is expeditiously undertaking steps that will result in an effective FRR-RS by the 2020 BRA. PJM may not reject such a certification based on the potential or perceived impact said waiver would have on the 2019 BRA, and the certification may not be rebutted or contested by other market participants. This certification could be made by a representative in the Organization of PJM States, Inc. for either a state that has incentivized the development of the resource or in the state in which the resource is located. This state-requested waiver of the MOPR would be available for only one year, in which time states would be expected to put in place the legal framework to enable use of FRR-RS.

\textsuperscript{78} *Emera Maine v. FERC*, 854 F.3d 9, 24-25 (D.C. Cir. 2017) (noting that the Commission’s “dual burden” under Section 206 includes putting forward a replacement that is just and reasonable and not unduly discriminatory and preferential).
The Commission will also need to implement a modified timeline for MOPR determinations and FRR-RS implementation for the 2019 BRA. Our FRR-RS proposal (and that of PJM) calls for FRR-RS elections to be made four months prior to the base residual auction, consistent with the FRR rules. This four-month period allows PJM ample time to evaluate those arrangements, and to provide market participants with time to incorporate the information about FRR-RS resources into their market offers. This notice period would have to be shortened for the 2019 BRA given that the Commission’s order could itself come within weeks of this four-month notice period for the 2019 BRA. However, we strongly encourage the Commission to shorten the notice period only for the first auction as a transition mechanism, rather than shortening the notice period for all future auctions as well, given the importance of this notice period for other market participants and PJM as the auction planning parameters are developed.

This transition mechanism is modest considering the scope of changes involved in the move to a bifurcated capacity construct. It addresses only the circumstance where state law poses a barrier to FRR-RS utilization, but otherwise allows full implementation of the MOPR to proceed, despite the rapid adaptation that will be needed by market participants to the very different new rules.

IV. CONCLUSION

For the foregoing reasons, Clean Energy and Consumer Advocates recommend that, assuming arguendo that the Commission does not reconsider its Order requiring a MOPR to be

79 Our proposal does call for FRR-RS elections closer to the time of the BRA, but only in the case where the resource has only become subject to the MOPR after the FRR-RS election date.
applied to resources based on the receipt of “out-of-market” payments, it should instruct PJM to develop a resource specific FRR construct consistent with the attached proposal and with the Joint Stakeholders’ Shared Principles for Designing FRR-RS. We also recommend that the Commission adopt a reasonable transition mechanism to delay full implementation of the MOPR until the framework for FRR-RS is in place at the state level.

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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.

Dated at New York, NY this 2nd of October, 2018.

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Attachment A
A Proposal for the Resource-Specific Fixed Resource Requirement that Accommodates State Public Policy Goals, Preserves the Capacity Market, and Protects Consumer Interests

October 2, 2018

Prepared by:
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I. INTRODUCTION

Broad application of the Minimum Offer Price Rule ("MOPR"), as envisioned in the Commission’s June 29, 2018 order in Docket Nos. ER18-1314 and ER18-178 ("MOPR Order"), has the potential to increase capacity costs for many PJM customers absent an effective mechanism to enable resources that receive out-of-market revenues to have their capacity recognized. The Commission’s order rejected both of PJM’s proposed packages of changes to the MOPR provisions under its tariff. Instead, FERC called for a paper hearing to develop expanded MOPR rules and a new option whereby resources could satisfy capacity obligations outside of the central Reliability Pricing Model ("RPM") capacity construct. In particular, the MOPR Order called for development of a resource-specific version of the existing Fixed Resource Requirement ("FRR") alternative (hereafter, “FRR-RS”). The Commission’s order envisions a bifurcated capacity market construct in which “resources receiving out-of-market support [could] to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time.” The MOPR Order recognized that there would be many details to be worked out about the FRR-RS design and included a list of questions in that regard.3

This paper offers a proposal for the FRR-RS that offers states, load-serving entities, and resources subject to the MOPR as much flexibility as possible while also closely tracking the Commission’s guidance in the MOPR Order. This paper does not address which resources should be subject to the MOPR or how the offer price floor should be calculated.

This proposal is based on an initial paper by Rob Gramlich of Grid Strategies LLC and James F. Wilson of Wilson Energy Economics, which was prepared in response to a request by PJM for stakeholder comments to inform PJM’s own response to the MOPR Order.4 The proposal reflects extensive subsequent discussion with a wide range of interested parties, including consumer advocates, state utility commissioners and staff, generators, and load-serving entities. This proposal is also consistent with the Shared Principles for a Resource-Specific Fixed Resource Requirement, a document signed by a larger number of diverse stakeholder interests, including the proponents of this proposal.

This paper first sets out a brief background of the relevant issues, then offers principles for the design of FRR-RS. A specific proposal for the FRR-RS, ranging from how eligibility is determined to how FRR-RS would operate in the delivery year, follows. The paper then proposes a particular transition mechanism and explains the need for the MOPR to be phased-in,

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1 Calpine Corporation et al v. PJM Interconnection, LLC, 163 FERC ¶ 61,236 (June 29, 2018) ("MOPR Order").

2 Id. P 160.

3 See id. PP 165-75.

and concludes with a question and answer section that addresses particular topics that have arisen in discussions around this proposal.

II. BACKGROUND

A. The Existing RPM FRR Rules

The original RPM design included a Fixed Resource Requirement (“FRR”) provision, negotiated as part of the RPM settlement, which is the only avenue for load to procure capacity outside of RPM.5 Under FRR, an eligible entity (most likely an electric distribution company, “EDC”) can choose to not participate in RPM and instead arrange a portfolio of capacity resources to meet its entire PJM-determined resource adequacy obligation. The FRR option faced opposition in the RPM settlement process, and as a result, is limited in its eligibility and use. The FRR provisions have been used by a few different entities over the years, in particular in the AEP zone. Outside of the AEP zone, less than one percent of the PJM resource adequacy need has been met under the FRR provisions.6

B. The Scope of the RPM MOPR

When RPM was first implemented over a decade ago, the MOPR was included as a provision to thwart any deliberate buyer-side attempt to suppress RPM prices, and in the first several base residual auctions it was never triggered. Over the years, the MOPR rules have been changed multiple times; in the MOPR Order, the purpose has shifted from mitigating the exercise of buyer-side market power to preventing any “price suppression” that could result from out-of-market revenues.7

In the MOPR Order, the Commission found PJM’s current MOPR unjust and unreasonable and initiated a process to expand the MOPR to cover all resources receiving out-of-market support, with few or no exceptions (including both new and existing resources).8 Thus, the MOPR, which to date has applied only to new, gas-fired resources, would be expanded to apply to new and existing resources that receive certain types of “out-of-market” revenues. It would extend even to resources that FERC has previously concluded are very unlikely to suppress market prices.9 FERC’s conclusion in the MOPR Order is that subsidized resources suppress RPM prices.

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7 MOPR Order P 155.
8 Id. P 157.
9 Id. P 155.
regardless of intent, resulting in unjust and unreasonable prices. At this time, FERC has not defined the scope of the MOPR or any exceptions from it.

III. PRINCIPLES FOR THE DESIGN OF THE FRR-RS

Though its scope is not yet known, the new, expanded MOPR will potentially result in more resources subject to administratively-determined minimum offer prices that are well above recent RPM clearing prices, and it appears likely that many of these resources will no longer be able to clear in RPM. The FRR-RS option can provide a path for such resources to serve as capacity resources and to receive compensation for their capacity.

The design of the FRR-RS provisions should be guided by the following principles:

1. The treatment of load and resources under the FRR-RS, together with capacity procurement under RPM, should continue to reliably satisfy PJM’s RTO-wide and locational resource adequacy objectives.

2. Price formation under RPM should continue to succeed in attracting and retaining sufficient resources to meet resource adequacy objectives.

3. The FRR-RS provisions should be as flexible as possible to meet these resource adequacy and price formation goals, without burdening the policy choices of states in the PJM region.

4. The contributions to resource adequacy of all capacity resources (both those offered through RPM and through FRR-RS) should be recognized. Loads should not have to pay for more capacity than necessary to meet resource adequacy needs—there should not be over-procurement or double payment.

5. There should be no difference in the obligations of RPM- and FRR-RS-committed resources; the only difference is in the mechanism these resources use to sell capacity. All provisions of the PJM Tariff and associated agreements should apply equally to FRR-RS-cleared and RPM-cleared resources. All resources that provide capacity, whether cleared through RPM or under FRR-RS, should provide the same Capacity Performance product. As under the existing FRR rules, load-serving entities (“LSEs”) should be free to contractually assume and pool the risk associated with the capacity performance obligations of the associated FRR-RS resources.

6. Introduction of the FRR-RS, and of the expanded MOPR rules it will accompany, should be coordinated to ensure a smooth transition and minimize uncertainty and disruption in the capacity market. Full implementation of the expanded MOPR before market participants are prepared to utilize the FRR-RS rules would lead to rates that are unjust and unreasonable. As such, a carefully considered transition mechanism is necessary to ensure rates that are fair and to avoid volatile RPM pricing.

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10 Id. PP 155-156.
11 Id. PP 165, 167 (seeking comment on the scope of the MOPR and exceptions thereto).
IV. A SPECIFIC PROPOSAL FOR FRR-RS

The following paragraphs propose how the FRR-RS could work, consistent with the guidance provided in the MOPR Order and the above principles. The current FRR rules are assumed to remain in place, consistent with the MOPR Order, and would not apply to resources’ and LSEs’ arrangements under FRR-RS.

A. Eligibility for FRR-RS

1. Resources that are subject to the MOPR would be eligible to elect FRR-RS. In addition, should rules be adopted that limit the ability of a resource that has previously participated in FRR-RS to re-enter RPM (which we do not recommend), such resources should remain eligible for FRR-RS even if they are no longer subject to the MOPR. See Q&A 10-11 infra.

2. A resource may elect less than 100% participation in FRR-RS if only part of such resource is subject to the MOPR or if the unit is jointly owned. Such a resource must provide its participating percentage and jurisdictional and zonal allocations when it makes its election.

B. Process for Electing FRR-RS

3. All resources that are eligible or potentially eligible to provide capacity (Capacity Performance, including seasonal Capacity Performance), whether intending to participate in RPM, in FRR-RS, or undecided in that regard, would go through a process before each base residual auction, as under the current rules, to have the following aspects of their eligibility determined:
   a. the resource’s eligibility to provide capacity (Capacity Performance, “CP”), either as annual or as Winter or Summer capacity resources;
   b. the resource’s unforced capacity (“UCAP”);
   c. whether the MOPR applies to the resource;
   d. whether the resource qualifies for any exemption from the MOPR;
   e. if the MOPR applies, the resource’s “Reference Price” (minimum allowed offer price), reflecting any applicable exemption or unit-specific exception, based on the yet-to-be-developed new MOPR rules.

4. PJM or its independent market monitor shall determine whether each capacity resource is eligible for FRR-RS (i.e., subject to the MOPR, and not covered by any exemption), as well as the applicable minimum offer price floor, at least 60 days in advance of the deadline for resources to elect FRR-RS.

5. Resources must indicate to PJM that they intend to elect FRR-RS no later than four months before each base residual auction, as under the current FRR rules. No later than one month

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12 See MOPR Order P 160 (“We are not proposing that PJM remove the existing FRR construct”).

13 RAA Sched. 8, Section C.1. Given that the time between a final FERC order and the 2019 BRA will likely be limited, we recommend a one-time transitional waiver to this deadline.
prior to the base residual auction, the FRR-RS election would be confirmed by the LSEs or state entities accepting the assignments and identifying the commensurate load. PJM would verify the compliance of the FRR-RS assignments with applicable rules.

6. In the event that a capacity resource becomes eligible for out-of-market revenues that trigger application of the MOPR within four months of the auction (i.e., after the FRR-RS election deadline), the capacity resource shall have two weeks to elect FRR-RS and identify commensurate load.

C. Identification of Commensurate Load

7. The load to be removed from the auction in connection with an FRR-RS election, i.e., the commensurate load, can be identified to PJM in a variety of ways, at the option of the FRR-RS eligible resource and ultimately subject to state authority. Resources that anticipate eligibility for FRR-RS could attempt to reach agreement with entities that have capacity purchase obligations (LSEs) to assign some or all of their capacity. State entities may also choose to facilitate matching of LSEs and FRR-RS eligible resources or could identity the commensurate load to be removed from the auction in any other way that is compatible with state preferences, including procurement programs or retail choice policies. See Q&A 5, 19-20, infra.

8. Agreements may be reached between LSEs and FRR-RS eligible resources without regard to whether the LSE also purchases RECs or ZECs from the resource, or to whether the LSE operates in the state under which the capacity resource has received out-of-market revenue rendering it eligible for FRR-RS. See Q&A 12, infra.

D. Requirements for FRR-RS Arrangements

9. Any payments for capacity from an FRR-RS resource would be subject to FERC’s jurisdiction. Consistent with their current authority under the Federal Power Act and insofar as permitted under state law, states may direct LSEs to enter into such contracts, provide regulatory guidance on capacity procurement by LSEs, or apply any other relevant state law framework to ensure the reasonableness of retail rates affected by decisions to purchase capacity through RPM or FRR-RS.

10. An FRR-RS resource’s unforced capacity (“UCAP”) would reduce the RPM capacity purchase obligation of the commensurate load (which is also expressed in UCAP, and reflects the required reserve margin) on a MW for MW basis, as under the current FRR rules. See Q&A 4, infra.

11. Seasonal FRR-RS resources would be able to form commercial aggregates based on matched amounts of Summer and Winter capacity, and such aggregates would be treated the same as commercial aggregates of RPM resources. Although the in-auction aggregation mechanism in

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14 RAA Schedule 8 Section D.2; see also the RPM Planning Parameters for each base residual auction, calculating the Preliminary FRR Obligation as the Total Peak Load of FRR Entities times the FPR.
RPM would not be available, LSEs or state entities could facilitate matching of complementary seasonal resources to form aggregates. See Q&A 15, infra.

12. Locational requirements would apply to FRR-RS arrangements. Resources located in constrained locational deliverability areas (“LDAs”) could be assigned to LSEs in the same LDA, in a surrounding, “parent” LDA, or in the RTO region without restriction. However, an FRR-RS arrangement could not exceed an LSE’s share of the zonal import limits, such that the LSE’s total capacity procurement across both FRR-RS and RPM will conform to the minimum Percentage of Internal Resources Required, as under the current FRR rules. Any external resources that become eligible for FRR-RS would be treated in the same manner. See Q&A 18, infra.

13. Market power oversight would be performed by FERC as for other wholesale transactions.

14. Resources would not be subject to any minimum duration as an FRR-RS resource or otherwise barred from returning to RPM. However, to limit the potential for the FRR-RS to be used to evade the MOPR, while still ensuring maximum flexibility for resources, resources that enter RPM for the first time after having only served previously as an FRR-RS resource, should be subject to a MOPR price floor calculated as though the resource were new. (In subsequent Base Residual Auctions, the MOPR rules would apply normally, including potentially applying the MOPR reference price as an existing resource, regardless of whether the resource cleared in the first auction after leaving the FRR-RS.) See Q&A 2, 3, infra.

E. Treatment in Base Residual Auction

15. Prior to calculating the Variable Resource Requirement (“VRR”) capacity demand curves, the Reliability Requirement in each zone would be reduced by the sum of the commensurate loads in the zone associated with the FRR-RS assignments. The Capacity Emergency Transfer Limits (CETL) consumed by FRR-RS assignments to locational commensurate loads would also be removed from the auction. The RPM base residual auction would be held using the adjusted VRR curves and CETL values, and without participation by the FRR-RS resources, as now with the current FRR rules. See Q&A 17, infra.

16. Consistent with current RPM cost allocation practices, PJM would allocate RPM costs among LSEs in a zone after taking into consideration FRR-RS arrangements with resources outside that zone; i.e., to the extent that a zone has a separate price, any LSE would be assigned costs associated with the more expensive internal resources that cleared the auction to the extent that it has not satisfied its internal resource obligation with FRR-RS resources. See Q&A 18, infra.

F. Adjustments from the Base Residual Auction to the Delivery Year

17. FRR-RS capacity resources, and the LSEs to which they may be assigned, would have the opportunity to adjust their capacity commitments as needed, similar to the opportunity available to RPM participants. Such replacements could occur, for example, where a capacity

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15 RAA Schedule 8 Section D.5.
resource’s UCAP changes, becomes unavailable, or is subsequently determined to be ineligible for FRR-RS. However, FRR-RS capacity would not participate in the RPM incremental auctions and could only be replaced by other, eligible FRR-RS capacity, and any replacement would also be subject to approval by the LSEs to which the FRR-RS capacity had been assigned. Alternately, if the FRR-RS capacity declines and cannot be replaced, the commensurate load is reduced, leading to incremental RPM capacity demand in the next incremental auction.

18. The same provisions applicable to RPM capacity would also apply to FRR-RS capacity with respect to ensuring that three-year forward capacity sales represent legitimate offers to provide capacity.

G. Operation of FRR-RS in the Delivery Year

19. Entering the delivery year, the UCAP values and commensurate load amounts of all FRR-RS resources would be updated to reflect updated outage rates, among other possible changes, as for RPM resources. Corresponding adjustments would be made to LSEs’ RPM capacity purchase obligations.

20. In the Delivery Year, all resources, whether committed through RPM or FRR-RS, are Capacity Performance resources (either annual or as aggregated seasonal resources) with all the same obligations, including performance obligations and penalties, monitoring and control, etc.

21. The allocation of RPM costs to LSEs would reflect LSEs’ capacity purchase obligations net of the final amount of capacity each has procured or been assigned through FRR-RS, and would also take into account the locational distribution of assigned FRR-RS resources.

V. TRANSITION MECHANISM

In proposing the FRR-RS, the Commission sought comment on whether some mechanism might be needed to “facilitate the transition to this new capacity construct,” noting that such mechanisms had been employed in the past where there were significant changes to the market design.” Many states may need to make changes to the statutory or regulatory frameworks for their clean energy procurement programs or other public policies to enable or optimally structure FRR-RS transactions. For example, several states may need to modify the rules for their default retail supply auctions (e.g., Basic Generation Service (BGS) or Standard Offer Service (SOS) auctions), pursuant to which suppliers compete to deliver a bundle of energy services that may include capacity purchased from PJM.

The kinds of changes needed are likely to depend in significant measure on the final rules approved by the Commission, and therefore cannot be undertaken until the final rules are in place. A smooth transition requires that the MOPR not be applied to resources that cannot yet use the FRR-RS due to state law. Applying the MOPR before the FRR-RS can be used could

16 MOPR Order at P 170.
17 Existing retail supply auction rules may reflect the fact that, with the exception of the existing FRR, the RPM is the only way for LSEs to purchase capacity in PJM.
lead to volatility in the market that would result from a resource clearing in RPM one year, not clearing the next year due to the MOPR, and in a third year participating in FRR-RS along with commensurate load. Premature application of the MOPR would also be costly for utility customers, who would have to pay for more capacity than needed to ensure resource adequacy.

As a mechanism to allow for a smooth transition, we propose that for the 2019 Base Residual Auction, a capacity resource that is subject to the MOPR can obtain a one-year waiver of the application of the MOPR if the state’s representative in the Organization of PJM States, Inc. certifies to PJM that the state has not yet been able to adopt the necessary legal or regulatory framework for capacity resources to utilize the FRR-RS effectively. Such a certification must document the state’s ongoing process (i) to adopt the needed state law provisions to enable use of FRR-RS, or (ii) to clarify existing state law where substantial uncertainty exists concerning its compatibility with FRR-RS. PJM shall accept such a certification if the state OPSI representative asserts in good faith that the state is expeditiously undertaking steps that will result in an effective FRR-RS program by the 2020 BRA. PJM may not reject such a certification based on the potential or perceived impact said waiver would have on the 2019 BRA, and the certification may not be rebutted or contested by other market participants. This certification could be made by a state that has incentivized the development of the resource or the state in which the resource is located. This state-requested waiver of the MOPR would be available for only one year, in which time states would be expected to put in place the legal framework to enable use of FRR-RS.

VI. QUESTIONS AND ANSWERS ABOUT THE FRR-RS PROPOSAL

This section provides responses to some likely questions about the FRR-RS proposal.

Q 1: What is the likely impact of the FRR-RS proposal on RPM prices and costs?

Compared to the status quo MOPR, the expanded MOPR suggested in the MOPR Order, without the FRR-RS option, would potentially result in a substantial increase in RPM prices and costs, at least in some zones, due to the broader application of the MOPR. If the FRR-RS option is added, and if it is successful and useful, it would largely offset the potential impact of an expanded MOPR and lead to RPM clearing prices closer to recent results.

Q 2: Would movement of resources between RPM and FRR-RS lead to uncertainty and disruption?

No. It will be rather predictable which resources will find FRR-RS attractive (many MOPRed resources), and such resources would generally not have much incentive to return to RPM. Restricting movement between RPM and FRR-RS unnecessarily has the potential to harm customers and result in unfair treatment of capacity resources. Uncertainty and disruption could, however, result from a hasty implementation of the new MOPR rules. If states have not had sufficient time to take necessary actions to enable use of FRR-RS, and market participants have not had sufficient time to make the necessary arrangements to use FRR-RS, the implementation of
the MOPR could lead to uncertainty and disruption, and possibly temporary RPM price spikes in some zones.

Q 3: The existing FRR rules include a five-year “minimum stay,” is there a need for such a requirement for FRR-RS?

No. There is no need for a minimum stay requirement in the case of the FRR-RS. FRR-RS is only open to resources that are MOPRed and, presumably, would not be able to clear in RPM. So an FRR-RS resource would generally see little reason to try to return to RPM.

An FRR-RS resource might consider returning to RPM if it appeared there could be a capacity shortage in its zone and RPM prices were likely to spike in the next RPM base residual auction. In that circumstance, if the FRR-RS resource and its commensurate load were to return to RPM, and if the resource were to clear at its Reference Price, that presumably would prevent an even higher price spike. Such an outcome should be preferred over an outcome with a more extreme price spike.

To the extent that a resource entering the market may attempt to utilize FRR-RS to circumvent application of the MOPR, that can be prevented through an anti-gaming provision that applies MOPR as though the resource were new on its first year electing to bid into RPM (in contrast, an existing resource that previously participated in RPM, became an FRR-RS resource, and then sought to re-enter the RPM would not be treated as “new”).

Q 4: Why is it appropriate for an FRR-RS resource’s unforced capacity (“UCAP”) to offset an LSE’s UCAP capacity obligation on a MW-for-MW basis?

The identification of “commensurate load” on a 1-for-1 UCAP basis results in the LSE doing its share to meet resource adequacy needs. This approach also comports with the current FRR rules. An LSE’s UCAP obligation is, roughly speaking, its peak load times the Forecast Pool Requirement (“FPR”), which typically is around 1.08. The FPR represents the margin of UCAP over peak load needed for resource adequacy. Looked at another way, for 100 MW of FRR-RS UCAP, the “commensurate [peak] load” that it can offset is 92.6 MW (100 MW x 1/1.08).

The RTO “installed reserve margin” is a more familiar measure and is typically around 16%. If an LSE meets its UCAP obligation with resources that have a 7% forced outage rate (that is, the resources’ UCAP is 93% of the installed capacity), then the LSE has arranged a 16.1% installed reserve margin (peak load x 1.08 x 1/0.93 = 1.161). FRR-RS resources are subject to the same performance requirements as RPM resources and accordingly provide the same value in meeting the installed reserve margin and location-specific needs.
Q 5: Which LSEs will contract for the capacity of FRR-RS resources? Will states need to get involved to make this happen?

Any LSE could contract with an FRR-RS resource for the assignment of its capacity, and presumably should be willing to pay a price close to the anticipated RPM price for the capacity.

States may choose to encourage or require such assignments through legislative or regulatory actions. For example, a state could require jurisdictional entities to contract for specific quantities of certain types of FRR-RS resources and provide for cost recovery as needed. The FRR-RS rules would not in any way encourage (or discourage) such state actions, but the rules should make clear that such actions would be consistent with states’ longstanding authority under the Federal Power Act.

Q 6: Would states, or LSEs, have to enter into Power Purchase Agreements (“PPAs”) to be able to use the FRR-RS option?

No. The agreement between an FRR-RS resource and an LSE needs only to accomplish an assignment of the FRR-RS resource’s UCAP.

Q 7: Under FRR or the proposed FRR-RS, the requirement is fixed, while under RPM, the RPM Base Residual Auction is cleared against a sloped Variable Resource Requirement (“VRR”) capacity demand curve, and may clear more or less than the reliability requirement. Is this fair to all customers?

Yes, this is fair to all customers. The base residual auction may (and typically does) clear a quantity different from the reliability requirement (peak load times FPR) due to the sloped VRR demand curves, and usually a larger quantity is cleared. However, to the extent a larger quantity is cleared, the clearing price and total capacity cost (price times quantity) are actually lower, due to the sloped demand curve. So while customers who are relatively more exposed to RPM may be nominally paying for relatively more MW of capacity, to the extent this occurs they will actually incur less capacity cost than if RPM (like FRR and FRR-RS) cleared exactly the reliability requirement.

The sloped demand curves were implemented to provide greater price stability, and to recognize that when capacity is relatively inexpensive [or expensive], it is appropriate to acquire relatively more [or less]. The sloped demand curves provide benefits to the loads and resources participating in the RPM auctions, and these benefits (and the associated quantity outcomes) are not applicable to the loads and resources that are being matched under FRR or FRR-RS.
Q 8: Is there a need to reconsider the shape of the VRR curves when the FRR-RS option is implemented?

No, the FRR-RS option does not create a need to change these curves. The VRR curve shape already naturally adjusts to larger and smaller zones because the quantity points are defined based on percentages of the reliability requirement. The current VRR curve shape has been used to clear zones as large as the RTO and as small as DPL South (with a reliability requirement under 3,000 MW). So if a zone shrinks due to FRR-RS election, the VRR curve adjusts accordingly.

Q 9: Will the existing FRR provisions remain and still be used? What is the relationship between the proposed resource-specific FRR-RS option and the existing FRR?

The existing FRR provisions provide an option for an LSE to satisfy 100% of its capacity obligations using any RPM-eligible resources (subject to the locational constraints), while only those resources subject to the MOPR are eligible for FRR-RS. So a role remains for the existing FRR option alongside the resource-specific FRR-RS.

Q 10: Should the FRR-RS option be opened up to all capacity resources, not just MOPRed resources?

This is a possibility that should be considered. There would seem to be no reason not to open up FRR-RS to all resources. As Commissioner Glick suggested in his dissent in the MOPR Order, allowing any resource to participate in FRR-RS would “give customers more flexibility and forestall continuous litigation regarding arbitrary judgments or cutoffs for resource eligibility.”

With that approach, the existing FRR option, which is less flexible, would no longer be needed or attractive.

Q 11: If the FRR-RS option is opened up to all capacity resources, would some additional restrictions be appropriate?

It may be appropriate to impose some of the restrictions under the FRR rules to non-MOPRed resources that elect FRR-RS. For instance, it may be appropriate to impose “minimum stay” restrictions on the non-MOPRed resources.

Q 12: Would there need to be a connection between FRR-RS capacity assignments and sales of Renewable Energy Credits (“RECs”)? Would capacity assignments and REC sales need to be bundled?

No. FRR-RS resources would not be limited to assigning their capacity and RECs to the same entity. States may implement policies that would cause that to occur, but the FRR-RS rules would not in any way encourage (or discourage) such arrangements.

18 MOPR Order (Glick, dissenting).
Q 13: Would some states need to pass legislation to be able to take advantage of the FRR-RS option?

Each state has different circumstances, and it is quite possible that there would be barriers to the contracting of FRR-RS resources in some state without changes to existing legislation, or renegotiation of existing contracts with renewable resources. However, LSEs could voluntarily enter into agreements to accept assignments of FRR-RS capacity and could potentially reduce their total capacity costs by doing so.

Q 14: How might the results of PJM’s current Fuel Security initiative impact the FRR-RS proposal?

PJM’s Fuel Security initiative could result in additional constraints imposed on the RPM base residual auction results (similar to the current locational constraints), or adjustments to certain resources UCAP values to reflect fuel [in]security; other outcomes are also possible. Any changes would apply to FRR-RS resources and to the contracting LSEs, analogous to the way locational constraints apply under the existing FRR rules.

Q 15: How might implementation of seasonal capacity procurement impact the FRR-RS proposal?

If PJM implements seasonal capacity procurement in some form (as discussed at a recent technical conference), the changes could have a substantial, positive impact on FRR-RS resources, especially wind and solar resources whose UCAP values are relatively seasonal.

Q 16: The discussion of an expanded MOPR has focused on state subsidies. If the MOPR is also extended to resources receiving federal subsidies, what impact would this have on the FRR-RS proposal?

If the MOPR is further expanded, the affected resources should also be allowed to pursue the FRR-RS option.

Q 17: Must FRR-RS resources and associated commensurate load be removed from the auction, rather than cleared through the auction as other parties have recommended?

Our position is that it is preferable for FRR-RS resources and commensurate load to be removed from the auction, and we read FERC’s order to indicate that it intended such resources to be removed from the auction. For example, FERC stated that FRR-RS resources would “exit the capacity market with a commensurate amount of load and operating reserves,” and that “[r]esources and load that take advantage of this new resource-specific FRR Alternative would not participate in the PJM capacity market, and would neither make nor receive payments from that capacity market.”\footnote{MOPR Order P 160.} However, clearing these resources through the market may have certain

\footnote{MOPR Order P 160.}
administrative advantages for FRR-RS participants. For example, it might lower the barrier to FRR-RS participation by smaller competitive retail suppliers, or it might allow a smoother transition for states with retail supply auctions designed around obtaining capacity solely through RPM.

**Q 18: How would LSEs’ ability to enter in FRR-RS arrangements be affected by transmission constraints?**

LSEs would not be able to enter in FRR-RS arrangements for an amount of capacity that exceeds that LSE’s share of the zone’s Capacity Emergency Transfer Limit (CETL). Likewise, states facilitating FRR-RS arrangements on behalf of load would not be able procure capacity through FRR-RS that exceeded the sum of CETL shares for the associated LSEs. This approach adheres closely to the existing policy for FRR Alternative Capacity Plans, which are subject to a “Percentage of Internal Resources Required.” The LSE or state could then procure the needed portion of internal resources through the BRA.

**Q 19: Under your proposal for the FRR-RS, would states need to have authority to order competitive retail suppliers to enter into bilateral contracts for FRR-RS capacity or otherwise regulate their capacity procurement?**

No. This proposal is intended to allow states flexibility in how FRR-RS is implemented for its load and the capacity resources it has incentivized, in recognition of the various ways that state procurement policies and retail choice laws are structured. Competitive retail suppliers would be expected to seek out low-cost capacity in order to offer lower prices to customers, which would involve a comparison of the cost of procuring capacity from FRR-RS eligible resources and from RPM. State control over retail suppliers is not necessary for the FRR-RS to work.

**Q 20: Could a state use different mechanisms to identify the commensurate load associated with different types of capacity?**

Yes. A state might have multiple clean energy procurement programs with different structures that are best complemented by different capacity procurement strategies. One program may involve a state-facilitated procurement that lends itself to a bundled contract for the environmental attribute and capacity between a state procurement agency and the capacity resource, in which the capacity credit is allocated pro rata to relevant load in the state. Another program may rely on LSEs to do their own clean energy procurement, in which case a bilateral capacity contract in which the commensurate load is subtracted from the procuring LSE’s reliability requirement makes the most sense. States should not be required to choose a single strategy in these circumstances, but instead to use a mix of strategies that best suit their local circumstances.

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20 RAA Sched. 8, Section D.5.
Q 21: How would your proposal work for a state with a default retail supply auction, e.g., BGS or SOS auction?

This proposal could work seamlessly with a state’s default retail supply auction, though FRR-RS purchasing decisions could influence competition in such auctions. Rather than assigning a PJM capacity purchase obligation to all retail supply auction winners for the entirety of the load they are awarded to serve, state regulations would need to specify that a winning supplier would only incur an obligation to purchase capacity from the RPM to the extent that the supplier has not secured adequate capacity through FRR-RS. Limits on the amount of capacity any one supplier may purchase through FRR-RS may be necessary in order to preserve competition in default retail supplier auction. Changes to default retail supply auction rules are one example of state regulatory changes that will likely need to be made regardless of the approach used to implementing FRR-RS, underscoring the need for an appropriate transition mechanism.
Attachment B
FERC’s June 29, 2018 order in Docket No. EL18-178 proposes implementation of a resource-specific Fixed Resource Requirement (FRR-RS) to provide an opportunity for the PJM market to account for the capacity contributions of state-incentivized resources. The undersigned parties endorse the following principles and terms for designing the proposed FRR-RS mechanism. This proposal is not intended to address questions regarding applicability of the Minimum Offer Price Rule (MOPR), but rather to describe eligibility for and functioning of the FRR-RS.

An FRR-RS mechanism should:

- Protect customers from paying for duplicate capacity. Expanding PJM’s MOPR likely will prevent many state-incentivized nuclear and renewable resources from clearing the PJM capacity auction. Without a workable FRR-RS that provides an alternative way to compensate these resources for their capacity, customers will be forced to buy excess capacity through the PJM capacity market to “replace” the renewable and nuclear energy supported by the states but ignored by the capacity market. A workable FRR-RS would prevent these increased costs.

- Preserve states’ abilities to achieve clean energy policy goals. Reducing the amount of capacity sold in the PJM auction by the amount of state-incentivized clean energy covered under an FRR-RS mechanism makes it possible for states to meet and expand their energy policy targets without being financially penalized.

Specifically, FERC should:

- Require FRR-RS to allow load serving entities to buy capacity from all state-incentivized resources and receive full capacity credit for doing so. The FRR-RS should provide maximum flexibility for the matching of customer load and state-incentivized resources, and provide a user-friendly mechanism for states to direct their load serving entities to procure capacity from state-incentivized resources.

- Allow for a smooth transition by giving states enough time to work through any difficult implementation issues before fully imposing the MOPR. States must be able to understand the new rules and clarify state law as needed to take full advantage of FRR-RS optionality. Because implementing FRR-RS effectively will require new regulation and/or legislation in many states, a transition mechanism must be established that allows for these processes to be carried out without forcing customers to pay excess costs in the interim.

The elements of a workable FRR-RS set forth in the shared principles below protect the cost-effective achievement of state policy goals to the extent possible under the terms of FERC’s PJM capacity market order in Docket No. EL18-178.
### Shared Principles for Designing FRR-RS

#### Implementation Timing

Because the FRR-RS is intended to mitigate the harm that would be caused by broad application of the MOPR, FERC should develop an implementation timeline for the expanded MOPR that reflects that states may need to adjust or clarify state law to utilize the FRR-RS opportunity. This may not be possible in a few months, especially where legislative action is needed.

#### Eligibility for FRR-RS

At a minimum, any supply resource subject to the MOPR under its newly expanded terms, or otherwise excluded from RPM participation based on previous participation in FRR-RS, is eligible for FRR-RS.

Eligibility determinations (and determinations as to whether the MOPR covers a particular resource) must be made by PJM sufficiently far in advance of when a resource must make its decision to elect to utilize FRR-RS or offer into the auction such that the resource (and associated load) can make an informed decision with respect to that resource.

FERC must make the scope of MOPR and FRR-RS eligibility as clear as possible in its order, such that states are able to legislate with knowledge as to how state rules will be treated by FERC. For example, the PJM tariff must make clear how a state program calling for capacity or bundled procurement from a chosen resource type will be treated (i.e., it must either state that such an arrangement would be subject to MOPR and thus render the capacity eligible for FRR-RS, or else state that the resource would not be subject to MOPR).

#### Process for Electing FRR-RS

At the time of the FRR-RS election, the capacity resource must identify the location of the load that will be removed with the resource, with enough specificity to permit compliance with locational constraints in the auction. This election and documentation setting forth compensation must be confirmed by a load serving entity (LSE) or other relevant entity (e.g., state power authority) by 30 days prior to the Base Residual Auction (BRA).

Thus, prior to the FRR-RS election, capacity resources will assign their capacity forward outside of RPM through a state-sponsored procurement process or directly to LSEs without state facilitation. Forward capacity assignments can be for unbundled capacity alone or for bundled capacity and other attributes (e.g., RECs or ZECs).
## Shared Principles for a Resource-Specific Fixed Resource Requirement

### Timing of Election
Consistent with the existing FRR, FRR-RS election must be made no less than four months before the PJM BRA. As explained above, PJM must indicate whether a resource is subject to the MOPR and therefore eligible for FRR-RS in advance of such election.

### Locational Restrictions on FRR-RS Election
PJM zonal import limits shall be respected in FRR-RS arrangements.

### Amount of Commensurate Load
RPM reliability requirements (taking into account reserves) for an LSE shall be reduced on a 1-for-1 UCAP basis according to the amount of UCAP procured through FRR-RS by or on behalf of that LSE.

### FRR-RS Resource Compensation
Capacity from FRR-RS resources shall be compensated as set forth in documentation confirmed by the LSE or other relevant entity, e.g., according to the terms of a bilateral contract with an LSE, or consistent with the state-sponsored procurement process. Such compensation could include cost-based pricing, competitively procured pricing, environmental attribute pricing and/or other state-established compensation mechanism, subject to EQR reporting and FERC review under Section 206.

### FRR-RS Billing and Administration
At the option of the state or LSE (as indicated in the documentation submitted by the FRR-RS resource to PJM), PJM will use its existing billing and accounting mechanisms to collect costs from the load and disburse payment to FRR-RS resources consistent with the FRR-RS documentation provided to PJM.

### FRR-RS Capacity Performance Requirements
Consistent with the current FRR, FRR-RS resources will be Capacity Performance Resources subject to all performance requirements, non-performance charges, and bonus payments. LSEs shall have the option to contractually assume from the resource responsibility for Capacity Performance charges and bonuses (facilitating pooling risk among smaller FRR-RS eligible resources). PJM will continue to review the performance of Capacity Performance resources, whether individual or aggregated, as it does today, including the assessment of performance and application of non-performance charges or bonus payments. A state may determine how non-performance charges and bonus payments are allocated among a portfolio of FRR-RS resources that, as a whole, functions as a Capacity Performance resource.

### FRR-RS Election for a Portion of a Resource
FRR-RS election shall be allowed for a portion of a resource if (i) the resource separates its capacity for purposes of offering into RPM and (ii) no capacity electing FRR-RS treatment is contained in any segment of capacity participating in RPM. A resource electing less than 100% FRR-RS must provide its participating percentage when it makes its election. Rules and practices governing the submission of offers by joint owners of individual generating units shall remain unchanged and, therefore, an FRR-RS election by one joint owner shall not affect RPM participation by the other owner.
FRR-RS Duration

Resources shall not be obligated to continue to elect FRR-RS for a minimum period of time. The only temporal restrictions shall be those needed to preserve reliability, such as the provision regarding notice of FRR-RS election.

FRR-RS Affiliate Transactions

A wholesale sale from an FRR-RS resource with FERC market-based rate authority to an affiliated LSE with captive customers undertaken pursuant to a state-incentivized clean energy program shall not be subject to the section 205 filing requirement under the seller’s market-based rate tariff if the procurement was consistent with the rules governing the state program, in recognition of the state’s jurisdiction over the compensation for environmental attributes. Any party seeking to challenge such a wholesale sale could initiate a section 206 proceeding seeking FERC review of the transaction. During such review, the party challenging the wholesale sale may demonstrate that adjustment of the rates, terms or conditions of the wholesale sale is necessary to protect retail customers from affiliate abuse. To facilitate prompt review of affiliated FRR-RS arrangements by interested parties, the documentation submitted with each FRR-RS election must indicate FRR-RS resource is selling capacity to an affiliated LSE with captive customers and must delineate the price under the contract for all capacity, energy ancillary services, and state-jurisdictional emissions benefits credits being sold, and PJM shall include such information in its postings regarding FRR-RS elections.

These principles are endorsed by the undersigned organizations:

Citizens Utility Board of Illinois
Exelon Corporation
Natural Resources Defense Council
Nuclear Energy Institute
Office of People’s Counsel for the District of Columbia
Public Service Electric and Gas Company
Sierra Club
Talen Energy
Attachment C
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. EL18-178-000

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE COMMENTS OF THE
FRR-RS SUPPORTERS

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I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have thirty-five years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission (“Commission”), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, Russia, and other regions. With regard to the PJM system, I have also been involved in a broad range of other market design and planning issues over the past several years.
4. With regard to the capacity market design issues that are the subject of this proceeding, I have been involved in these issues in PJM, New England, California, the Midwest, and other regions. Since PJM Interconnection, L.L.C. (“PJM”) proposed the Reliability Pricing Model (“RPM”) capacity construct in 2005, I have prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues, including the minimum offer price rule (“MOPR”) policies addressed in this docket. I submitted comments in the Commission’s technical conference on state policies and wholesale markets in Docket No. AD17-11.\(^1\) I actively participated in the Capacity Construct Public Policy Senior Task Force (“CCPPSTF”) stakeholder process and prepared an affidavit\(^2\) that was attached to three protests in response to PJM’s Capacity Repricing Filing\(^3\) in Docket No. ER18-1314-000.

5. In an order dated June 29, 2018 in Docket No. ER18-1314-000\(^4\) the Commission rejected both of PJM’s proposed packages of changes to the MOPR provisions under its tariff. The Commission called for a paper hearing to develop expanded MOPR rules and a new option whereby resources could satisfy load capacity obligations outside of the RPM capacity construct. In particular, the June 29 Order at P 160 called for a resource-specific version of the existing Fixed Resource Requirement (“FRR”) alternative (hereafter, “FRR-RS”).

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6. This affidavit was prepared at the request of Sierra Club, Natural Resources Defense Council, and the Office of the People’s Counsel for the District of Columbia. My assignment was to discuss the principles that should guide the design of the FRR-RS, FRR-RS design elements, and RPM performance with the FRR-RS option.

II. Summary and Recommendations

7. The June 29 Order calls for expanding the MOPR and establishing a new FRR-RS option. The MOPR has the potential to substantially raise RPM clearing prices while causing some existing resources not to clear; the FRR-RS alternative could potentially offset and moderate some of the impact of the expanded MOPR. The June 29 Order suggests that an expanded MOPR, with the FRR-RS option, could be just and reasonable. As such, it is important for the FRR-RS option to be a realistic and usable option. However, as the Organization of PJM States Inc. has warned, even if FRR-RS is well-designed, many states likely will not be able to take advantage of the opportunity in the near term:5

“While a FRR Alternative approach may align with certain states’ policies, many states never contemplated procurement of capacity from specific resources under a restructured framework. As such, many states do not currently have, and may not have time to develop, enact and implement, the enabling authority necessary to facilitate selective capacity procurements like those envisioned under the FRR Alternative approach in time for the next PJM Base Residual Auction (BRA).”

8. I identify several common-sense objectives and principles that should guide the design of the FRR-RS provisions, and comment on some specific FRR-RS design elements. These

objectives, principles, and design elements are directed toward ensuring that the FRR-RS provisions are as flexible and usable as possible consistent with satisfying resource adequacy objectives, maintaining accurate RPM price signals, treating all resources in a non-discriminatory manner, and protecting against market power.

9. I also explain why RPM will continue to produce accurate price signals with the expanded MOPR and FRR-RS provisions, without any administrative “repricing” approach; and how repricing would cause excess capacity to clear at excess cost. My discussion employs the dynamic perspective that historically has been used to evaluate RPM performance, rather than the simplified, static-type analysis that has more recently been used to raise concerns about alleged “price suppression.”

III. Background

A. The Scope of the RPM MOPR

10. When RPM was first implemented over a decade ago, the MOPR was included as a provision to thwart any deliberate buyer-side attempt to suppress RPM prices. In the first several base residual auctions it was never triggered. Over the years, the MOPR rules have been changed multiple times, and its mission has expanded. The Commission’s position is now that subsidized resources suppress RPM prices, regardless of intent, resulting in unjust and unreasonable prices. In the June 29 Order, the Commission found PJM’s current MOPR unjust and unreasonable, and initiated a process to expand the MOPR to cover all resources (including both new and existing resources) that receive state-sponsored, out-of-market support. Thus, the MOPR, which to date

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6 June 29 Order, PP 155-156.
7 June 29 Order, P 157.
has applied only to new, gas-fired resources, would be expanded to apply to new and existing resources that receive state support, including certain renewables. Under this framework, the MOPR will apply to resources with out-of-market state support; it will no longer focus on exercise of market power or deliberate attempts to suppress prices.

11. While calling for further expansion of the MOPR, the June 29 Order recognized that this fails to accommodate resources in the market with state support pursuant to state policy objectives, and could lead to consumers having to pay twice for capacity. Accordingly, the Commission called for the resource-specific FRR option. The FRR-RS option would afford resources to which the MOPR would apply an opportunity to serve as capacity and to have their contributions to resource adequacy recognized, while protecting RPM price formation from the alleged impact of such resources’ state support.

B. The Existing RPM FRR Rules

12. The FRR-RS option builds on the Fixed Resource Requirement (“FRR”) provisions that were negotiated as part of the RPM settlement. Under FRR, an investor-owned utility, public power entity, or electric cooperative could choose to not participate in RPM and instead arrange a portfolio of capacity resources to meet its entire PJM-determined resource adequacy obligation for its entire service area for a minimum five-year period.

13. However, the FRR option faced opposition in the RPM settlement process, and, as a result, the design included provisions to restrict eligibility and make FRR difficult or unattractive

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8 June 29 Order PP 159-160.

to use. The FRR provisions have only been used by a few entities over the years, in particular in the AEP zone. Outside of the AEP zone, less than one percent of the PJM resource adequacy need has been met under the FRR provisions.10

C. The Resource-Specific FRR Option Proposed in the June 29 Order

14. The concept of FRR as an alternative for MOPRed resources was first discussed in a 2011 proceeding on the MOPR rules:11

“PJM’s tariff also provides an alternative for those load serving entities that wish to bring new generation resources into the PJM capacity market without risk of being mitigated under the MOPR. They may avail themselves of the FRR option to satisfy their capacity requirements.”

15. However, the various requirements and restrictions under the FRR rules rendered it impractical under nearly all circumstances.12

16. The concept of a more flexible FRR option to accommodate public policy resources was discussed in the PJM Capacity Construct Public Policy Senior Task Force stakeholder process in 2017; a similar concept was also discussed in a similar stakeholder process in New England.13 The June 29 Order, while calling for expansion of the MOPR, again raised the possibility of an FRR option, and provided the following guidance on the design of a resource-specific FRR alternative (P 160):

12 See, for instance, Wilson, James F. Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011 in Docket No. ER11-2875 (explaining that FRR was not practical for New Jersey, due to inflexible FRR provisions and the potential for exercise of market power).
“160. In addition to expanding PJM’s MOPR, we also preliminarily find that it may be just and reasonable to accommodate resources that receive out-of-market support, and mitigate or avoid the potential for double payment and over procurement, by implementing a resource-specific FRR Alternative option. We therefore propose that PJM adapt its current FRR option to allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. The resource-specific FRR Alternative would accommodate such resources by allowing them to remain on the system, despite their inability to compete in the capacity market based on their costs, by permitting them to exit the capacity market with a commensurate amount of load and operating reserves (we seek comment on the best method of accounting for both the load and reserves, below). Resources and load that take advantage of this new resource-specific FRR Alternative would not participate in the PJM capacity market, and would neither make nor receive payments from that capacity market... Unlike the current FRR construct, the resource-specific version would not require a load-serving entity to remove its entire footprint from the capacity market; rather it would remove a specific resource (and accompanying load). However, we note that we are not proposing that PJM remove the existing FRR construct, which allows load-serving entities to exit the capacity market on a utility-wide basis.”

17. The June 29 Order recognized that many details would need to be worked out about the resource-specific FRR option, and included a list of questions (PP 164-172).

IV. Goals and Principles for the Design of the Resource-Specific FRR Option

18. Since the June 29 Order, I have worked with clients, other experts, and other PJM stakeholders to determine how the FRR-RS should be designed. This work first resulted in a July 27, 2017 paper co-authored with Rob Gramlich.14 Subsequently, PJM and other stakeholders

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proposed approaches to the resource-specific option,\textsuperscript{15} and a broad group of supporting stakeholders negotiated a document of shared principles for the design of FRR-RS.\textsuperscript{16}

19. The expanded scope of the MOPR will result in more resources subject to administratively-determined minimum offer prices that may be unable to clear in RPM. The FRR-RS option can provide a path for such resources to serve as capacity resources and to receive compensation for their capacity. I propose that the following goals and principles should guide the design of the FRR-RS provisions, to achieve the objectives without adverse impacts:

A. Price formation under RPM should continue to succeed in attracting and retaining sufficient resources to meet resource adequacy objectives, when accounting for the resources and loads participating through the FRR-RS.

B. The treatment of load and resources under the FRR-RS, together with capacity procurement under RPM, should continue to reliably satisfy PJM’s RTO-wide and locational resource adequacy objectives.

C. Through RPM and FRR-RS, the contributions to resource adequacy of all capacity resources should be recognized (loads should not have to “pay twice” for capacity, and the mechanism should not by design lead to excess capacity).

D. Subject to these price formation and resource adequacy goals, the FRR-RS provisions should be as flexible as possible to best accommodate resources that are receiving support according to state policy objectives. In particular, given the widely varying circumstances in different states within the PJM footprint, alternative approaches to identifying FRR-RS resources’ commensurate load should be accommodated, including bilateral contracts, or state-defined procurement processes.

E. All resources that provide capacity, whether cleared through RPM or under FRR-RS, should provide the same Capacity Performance product. Provisions of the PJM Tariff and associated agreements applicable to capacity resources should apply equally to FRR-RS-cleared and RPM-cleared resources. RPM-committed and FRR-RS-committed capacity resources are indistinguishable; they differ only in how the resources are contracted and compensated.

\textsuperscript{15} PJM, \textit{PJM Proposal Including Stakeholder Input}, Markets and Reliability Committee Special Session: PJM Response to FERC on Capacity Market Reforms, September 11, 2018 (matrix updated September 28, 2018); see also Joint Exhibit 1 filed in this proceeding.

F. Exercise of market power in the RPM and FRR-RS capacity market by sellers or buyers should be absent or mitigated.

G. FRR-RS resources should be permitted to return to RPM, however, the FRR-RS option must not be a vehicle for new resources to evade the MOPR.

H. The introduction of the FRR-RS rules, and of the expanded MOPR rules they will accompany, should be coordinated to ensure a smooth transition and minimize uncertainty and disruption in the capacity selection process. For example, a resource that is not mitigated under the current MOPR should not be MOPRed in the upcoming auction if the state fully intends to contract the resource under FRR-RS, but has not had sufficient time to enact the necessary enabling regulations.

V. Comments on Specific FRR-RS Design Elements

20. These goals and principles have implications for some of the specific FRR-RS design elements that have been discussed by PJM and stakeholders. The following paragraphs discuss a few FRR-RS design elements.

A. Amount of Commensurate Load

21. An FRR-RS resource’s unforced capacity (“UCAP”) should offset the RPM resource adequacy obligations assigned to loads, which are also measured in UCAP, on a MW UCAP-for-MW UCAP basis. This is the approach under the current FRR rules, and ensures that the commensurate load does its share to meet the total system resource adequacy needs.

22. An RPM or FRR-RS resource’s UCAP is calculated based on its forced outage rate (and, for variable resources, also reflects availability during peak periods) and represents its contribution to resource adequacy. The total UCAP reliability requirement to meet resource adequacy objectives, which is consistent with the total system required installed reserve margin

17 RAA Schedule 8.1 Section D.2; see also the RPM Planning Parameters for each base residual auction, calculating the Preliminary FRR Obligation as the Total Peak Load of FRR Entities times the Forecast Pool Requirement.
(“IRM”), is allocated to Load-serving entities (“LSEs”) based on their peak loads, increased by the Forecast Pool Requirement (“FPR”). For example, PJM’s 2017 Reserve Requirement Study\(^\text{18}\) identified, for the 2021-2022 delivery year, an IRM of 15.8\%, an RTO-wide average forced outage rate (“EFORd”) of 5.89\%, and an FPR of 1.0898, and noted that these three values bear the following relationship (p. 20):

\[
\text{FPR} = (1 + \text{IRM}) \times (1 - \text{PJM Avg. EFORd})
\]

23. Thus, offsetting load on a MW UCAP for MW UCAP basis ensures that the load’s share of the Forecast Pool Requirement and Installed Reserve Margin are satisfied.

24. As a numerical example, consider a resource rated at 200 MW of installed capacity that elects to participate in FRR-RS. Suppose this resource has an 8\% forced outage rate, so it represents 184 MW UCAP (200 x 0.92). The resource should offset 184 MW of UCAP obligation, which, applying the FPR, corresponds to 168.84 MW of peak load (184 / 1.0898). Therefore, 200 MW installed capacity assigned to 168.84 MW of commensurate peak load satisfies the 15.8\% Installed Reserve Margin (200 / 168.84 = 115.8).

25. The RPM Base Residual Auctions are cleared against sloped Variable Resource Requirement (“VRR”) capacity demand curves, which may result in clearing capacity quantities that are different (larger or smaller) than the requirements based on the FPR and IRM. Under the FRR rules, the resource requirement is fixed, and there is no quantity adjustment or special cost allocation to FRR entities based on RPM results. This is appropriate and fair to all customers, and the same approach should apply to FRR-RS and the commensurate load.

26. In particular, it would not be appropriate to assign additional capacity obligation or capacity cost to FRR entities or FRR-RS commensurate loads when RPM clears an excess. While the excess capacity provides some additional reliability value to all customers, the FRR and FRR-RS loads have fully satisfied their fair share of the obligations to meet resource adequacy objectives before the auction. If RPM clears excess capacity as a result of its sloped demand curves, this is an unnecessary outcome, and one that has to do with RPM considerations, not resource adequacy considerations.

27. The sloped demand curves were implemented to provide greater RPM price stability, and to recognize that when capacity is relatively inexpensive [or expensive], it is appropriate to acquire relatively more [or less]. The sloped demand curves moderate the potential price swings that could occur under a vertical or steep demand curve, and this provides benefits to the resources (and, indirectly, the loads) participating in RPM. These auction performance benefits, and the associated quantity outcomes, are not applicable to the loads and resources that are being matched under FRR or FRR-RS.

28. Note further that to the extent RPM clears a capacity quantity greater than the target amount based on FPR and IRM (as commonly occurs), the clearing price is lower, and total capacity cost (price times quantity) is also lower, due to the sloped demand curve. So while the loads whose capacity obligations are satisfied through RPM are nominally paying for relatively more MW of capacity when excess clears, they will actually incur a lower total cost of the capacity than if RPM (like FRR and FRR-RS) cleared exactly the reliability requirement.19

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19 For example, based on the VRR curve used for the RTO Region in the May 2018 base residual auction for the 2021-2022 delivery year, the total market cost (price times quantity) for the RTO region, if clearing at “Point A” (156,253 MW), would be $27.5 billion. If the larger “Point B” quantity clears (160,354 MW), the cost would be $14.1 billion. If an even larger quantity clears (midway between Point B and Point C; 164,533 MW), the cost would be $7.2 billion.
29. I also note that while clearing excess capacity in RPM likely has an incremental resource adequacy benefit and lowers total capacity cost, it is not without its drawbacks. Clearing excess capacity results in low capacity prices that may not be sufficient to attract new entry, and the excess capacity can also result in suppressed prices in energy and ancillary services markets.

B. Minimum Stay Requirements

30. The FRR rules require a load-serving entity electing the FRR option to remain under FRR for a minimum of five years (a “minimum stay” requirement); and once returning to RPM, there is also a five-year minimum duration before the entity becomes eligible to again elect FRR. These restrictions were placed on FRR as part of the RPM settlement process. They address concerns that FRR entities might otherwise opportunistically “toggle” back and forth between FRR and RPM based on portfolio circumstances and market conditions, potentially causing uncertainty and disruption to RPM.

31. However, there would not seem to be any need to impose such minimum stay requirements on resources electing FRR-RS. While all capacity resources in the RTO footprint (and eligible imports, too) are eligible to be included in an FRR plan, the FRR-RS option will only be available to resources that are MOPRed. Presumably, MOPRed resources would elect FRR-RS if they are unlikely to clear in RPM; accordingly, they would not have reason to desire to return to RPM. Therefore, the “toggling” concern is not applicable to these MOPRed resources.

32. An FRR-RS resource might consider returning to RPM if it appeared there could be a capacity shortage and RPM price spike in its zone in the next RPM base residual auction. In that circumstance, if an FRR-RS resource and its commensurate load were to return to RPM, and

20 RAA Schedule 8.1 Section C.2.
if the resource were to clear, that would seem to be a desirable outcome. The market would have expanded, with the additional resource participating, and the additional resource may help prevent an even higher price spike. Such an outcome should be preferred over an outcome with a smaller market and more extreme price spike. Thus, FRR-RS resources should be welcomed back to RPM.

33. A special case involves new resources that come into operation under FRR-RS. If such resources seek to return to RPM, the MOPR provisions applicable to new resources should apply. That is, the FRR-RS rules must not become a pathway for new resources to participate in RPM having evaded the application of the MOPR.

C. FRR-RS Participation Limits

34. Another circumstance that may warrant special treatment is a modeled RPM zone in which a high fraction of the capacity may be MOPRed and seek FRR-RS status. Concern arises not due to the large quantity of FRR-RS, but to the potentially small quantity of load and resource that remains in the zone to clear under RPM.

35. Note that the RPM VRR curve shape naturally adjusts to larger and smaller zones, because the quantity points are defined based on percentages of the reliability requirement. The current VRR curve shape has been used to clear zones as large as the RTO and as small as DPL South (with a reliability requirement under 3,000 MW). This means that if the participating RPM load and resources shrink due to FRR-RS election, the VRR curves adjust accordingly.

36. However, if nearly all resource and load in a modeled zone seek FRR-RS and/or FRR status, perhaps there should be provisions in place to ensure that this does not result in an extremely small modeled zone in the RPM auction. One approach could be to set a minimum size threshold that triggers special rules. The threshold might be at the point where the remaining RPM UCAP load is less than ten percent of the modeled zone’s total reliability requirement, or less than
2,000 MW. If FRR-RS elections cause the threshold to be passed, the zone would not be modeled in the RPM base residual auction. The rules would address how the zone’s residual load and resources participate in resource adequacy through RPM or FRR-RS.

VI. RPM Price Signals and Dynamic Efficiency with FRR-RS

37. This final section of my affidavit explains why RPM, with an expanded MOPR and the FRR-RS alternative, can be expected to continue to send accurate price signals, and to continue to attract and retain sufficient resources to meet resource adequacy objectives. Furthermore, administrative repricing provisions, such as those proposed by PJM, would be harmful and not improve the price signals or dynamic efficiency of RPM.

A. RPM Dynamic Equilibrium with FRR-RS

38. Whether RPM will send price signals sufficient to attract and retain enough capacity to satisfy resource adequacy objectives has been a fundamental question since RPM was first proposed in 2005. At that time, Prof. Benjamin Hobbs developed a dynamic model to simulate RPM operation over time in the face of load uncertainty, and representing forward-looking entry decisions by risk-averse investors.21 The “Hobbs Model” and variants of it have been used multiple times to evaluate RPM’s dynamic performance under various proposed changes to the RPM VRR curves or other RPM rules, including issues around demand response clearing and

incremental auctions. It has also been used for analysis of ISO New England’s Forward Capacity Market.

39. By contrast, the analysis of MOPR rules underlying claims about “price suppression” has been “static,” considering only a single auction, and holding the offer prices and quantities of all market participants constant. Such analysis does not allow market participants to react in any way to any changes to the price levels or market rules (by contrast, entrants in the dynamic Hobbs model take into account anticipated future energy and ancillary services earnings based on cleared capacity quantities). This type of simple, static analysis, which typically adds or removes one or a few resources from the supply curves while holding everything else constant, tends to show large impacts of small changes to supply, demand, or rules, including MOPR rules. In essence, such analysis evaluates an unexpected and last-minute “shock” or change to the market or market rules, one that market participants have no opportunity to adapt to.

40. In the real world, market participants are continuously monitoring changes to market demand, market supply, and market rules, and updating their expectations of future capacity prices. Their plans to bring forth new resources, or to retire existing resources, will reflect updated expectations of prices and the need for such resources, as I have many times explained.

41. The dynamic nature of RPM is reflected in recent auction results. Over the past several years, RPM base residual auctions have seen a substantial volume of entry and exit in each auction. Specifically, over the past six delivery years, the base residual auction has seen over

22 The Hobbs model was used by The Brattle Group in the 2008 and 2011 RPM Triennial Reviews, and in 2013 in the Capacity Senior Task Force stakeholder process.

23 As one example, see Monitoring Analytics, MOPR/FRR Sensitivity Analysis of the 2021-2022 RPM Base Residual Auction, September 26, 2018 (p. 1, claiming that the report “quantifies the impact of potential MOPR/FRR scenarios on market outcomes…”).

35,000 MW of incremental generation resources, while each auction has also had 11,000 to 18,000 MW of uncleared resources; and over six years from June 1, 2011 through June 1, 2017, just under 25,000 MW of installed capacity deactivated in PJM. Yet while RPM clearing prices vary from year to year, they seem to repeatedly return to a broad range around $100/MW-day for the RTO Region.

42. Market participants generally will select the timing of retirements and new capacity additions in anticipation of the RPM supply/demand balance and price level; if RPM prices are expected to rise, some retirements may be delayed or relatively more new entry may be offered, and if prices are expected to be soft there might be more retirements or some new entry may be delayed. Such adjustments have kept RPM prices within a limited range over the past several years despite the retirements and new entry. In addition, various short lead time resources that can efficiently take on RPM obligations, or not, on a year-by-year basis depending upon need and prices (such as some imports, some demand response, and resources that are economic on an energy-only basis) also tend to buffer the RPM price changes from year to year.

43. When certain additional resources are expected to enter or exit the market (be it “competitive” or sponsored resources), market participants will take these changes into account in planning the timing of retirements, other new entry, and other actions that affect the balance of supply and demand. If the additional resources or retirements are anticipated well in advance, it is reasonable to expect that they are fully anticipated and absorbed by market participants’ adjustments, and have minimal, if any, impact on capacity prices.

44. The expanded MOPR rules are likely to result in additional resources subject to administrative pricing and failing to clear. Other things equal, and based on a static rather than a dynamic analytical standpoint, the immediate impact of the expanded MOPR will be to raise RPM
prices. The new FRR-RS provisions will allow resources to which the MOPR would apply, and which might therefore not clear in RPM and not be counted toward resource adequacy requirements, an opportunity to offset commensurate load under FRR-RS and, therefore, contribute to resource adequacy. Thus, again from a static analysis standpoint, the FRR-RS provisions added to the new MOPR will, if effective, tend to lower RPM prices, countering the price-increasing impact of the expanded MOPR.

45. As to the combined impact of the changes to the MOPR and the addition of the FRR-RS rules (compared to the status quo) under a static analysis, this is hard to predict. If only a small portion of the resources to which the MOPR applies are able to effectively take advantage of the FRR-RS opportunity, the combined impact (again, based only on static analysis) will be to raise RPM prices. If, instead, more resources, perhaps including some that have failed to clear in recent RPM auctions, are able to take advantage of FRR-RS, it is possible that the combined impact of the new MOPR and FRR-RS, again based on static analysis, could be to lower RPM prices.

46. However, much more important is the impact from a dynamic, multi-auction perspective, taking into account that market participants will adjust their entry and exit choices based on the price signals they see, and anticipate, in RPM. Any short-term impact of the new rules, whether upward or downward, should wash out over time as entry and exit choices adjust to the expected shift in supply, demand and prices.

47. This is the dynamic captured in Prof. Hobbs’ model of RPM performance. The MOPR, and FRR-RS, would shift the RPM supply and demand curves, but not otherwise change the market rules or the various uncertainties faced by investors. Consequently, a dynamic analysis of RPM would show that RPM would find the same dynamic equilibrium, with the same price levels, with the addition of FRR-RS.
B. Impact of Capacity Repricing with FRR-RS

48. PJM’s various proposals for capacity “repricing” have been motivated by the “price suppression” suggested by the static-type analysis described above. The repricing proposals attempt to undo the potential price impact (which impact is identified based exclusively on static analysis) of a state-supported resource. As explained above, from the more relevant, dynamic perspective, repricing is unnecessary, as the market will move toward equilibrium with or without it.

49. In an affidavit earlier this year, I explained that PJM’s Repricing Proposal (as it stood at that time) exhibited three fatal flaws:25

1. The first fatal flaw was that PJM’s Repricing Proposal would establish an auction clearing price and quantity pair that was inconsistent with (lies well above) the VRR curve, and results in excessive capacity cost.

2. The second fatal flaw was that PJM’s Repricing Proposal divorced the determination of who clears in the auction from the determination of what price those winners will be paid, which would create two distortions to resources’ offer prices, with undesirable results.

3. The third fatal flaw was that under the proposal, the RPM clearing prices (that determine billions of dollars of capacity payments) could be set by offers from resources that have nothing at stake in selecting their offer prices, and indeed had incentives to inflate their offer prices; therefore, these prices could be quite arbitrary.

25 Wilson Repricing Affidavit, pp. 21-38.
50. I understand that despite the Commission’s rejection of its Capacity Repricing Proposal, PJM plans to re-submit it, with three changes:\(^{26}\)

1. State-sponsored resources would satisfy load obligations, but would not receive RPM payments;

2. For the repricing calculation, state-sponsored resources would be removed from the auction supply stack (rather than included at Reference Prices); and

3. Resources with offer prices below the Stage 2 repricing clearing price, but above the lower Stage 1 price used to determine which resources clear (that is, the so-called “tweener” resources) will apparently receive a payment:

   “PJM is considering paying the otherwise inframarginal resource that did not get a commitment in stage 1 with a lost opportunity cost that equals the difference between the resource clearing price and its offer price.”

51. The first two changes do not address the three flaws I had identified in my earlier affidavit, while the third change is apparently an attempt to address the incentive problems that result from the second of the three fatal flaws. As I noted in the Wilson Pricing Affidavit (p. 33, citations omitted):

   “Throughout the twenty-two meetings of the CCPPSTF, the incentives issues were repeatedly raised by various stakeholders, including stakeholders representing public power, capacity seller, and consumer interests (perhaps among other interests). However, PJM never responded to these concerns with any discussion or analysis; PJM’s only response has been to dismiss the concern as speculative, as it has in the PJM Filing.”

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52. However, with these changes, there would still be a disconnect between the determination of which resources clear and what they get paid, a characteristic to which the June 29 Order specifically objected (P. 64):

“We agree with intervenors that, by setting a clearing price that is disconnected from the price used to determine which resources receive capacity commitments, the market clearing price under Capacity Repricing will send incorrect signals, leading to greater uncertainty with respect to entry and exit decisions.”

53. With PJM’s proposed changes, this disconnect remains, but now all resources that offer below the repricing clearing price would apparently receive payments. The additional payments would increase the cost to consumers, while the impact of some new, to-be-defined payment on the incentive problems would likely be complex.

54. Under PJM’s revised proposal, the Capacity Repricing price will continue to send incorrect price signals leading to uncertainty about entry and exit decisions, because it will still ignore the fact that the removed state-sponsored resources will be meeting load capacity obligations. The ultimate cleared price and quantity will still be inconsistent with the auction VRR curve (Fatal Flaw #1), and the repricing clearing price can still be set by a resource that receives an administrative payment, but will not be providing capacity (Fatal Flaw #3).

55. While the revised repricing proposal could potentially have the price-supportive impact desired by PJM, to some extent, in the very short term, from a dynamic perspective the impact of repricing is very different. Even if market participants’ offers are not distorted by the proposal, as PJM hopes, repricing will ultimately simply lead to similar RPM clearing prices, while clearing a larger amount of excess capacity. Market participants will respond to the prices offered, and adjust their entry and exit decisions accordingly, until RPM prices return to the level market participants collectively consider adequately compensatory, as they have done repeatedly in the
past. A dynamic analysis of the proposal would show the futility of the repricing approach: ultimately resulting in similar prices, while clearing an even larger amount of excess capacity at an excessive cost.

56. This concludes my affidavit.
Exhibit F
Reply Comments of Clean Energy Advocates Separately Addressing the Scope of the Expanded Minimum Offer Pricing Rule, November 6, 2018
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, et al.                  Docket Nos. ER18-1314-000
v.                                            ER18-1314-001

PJM Interconnection, L.L.C.                   EL16-49-000
                                               EL18-178-000

REPLY COMMENTS OF CLEAN ENERGY ADVOCATES SEPARATELY
ADDRESSING THE SCOPE OF THE EXPANDED MINIMUM OFFER PRICING RULE

Natural Resources Defense Council, Sierra Club, and Sustainable FERC Project (collectively, “Clean Energy Advocates”) hereby submit comments in reply to the initial filings addressing the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) request for comments on a proposed replacement rate in its Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act (June 29, 2018) (“Order”). Clean Energy Advocates address in this filing only the portions of the initial comments pertaining to the scope of the minimum offer price rule (“MOPR”) to apply to the capacity market going forward. Clean Energy Advocates also join separate comments that address all other matters at issue in this proceeding, including the terms of a resource-specific Fixed Resource Requirement (“FRR”) alternative. The substance of those separate comments is not repeated here.
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COMMENT

I. **The MOPR “Medicine” is Worse than the Disease.**

Clean Energy Advocates have registered our deep concerns with MOPR expansion as a means to ensure just and reasonable rates from the start of this proceeding, and recent submissions and new evidence only reinforce the conclusion that the MOPR “medicine” is worse than the disease. Without repeating our objections that remain pending before the Commission, we highlight new information that further supports the conclusion that the Commission is heading in the wrong direction by attempting to undermine government policies that result in a competitive advantage for certain resources. At minimum, this additional information provides further grounds for a moderate approach, in acknowledgement that MOPR expansion may well do more harm than good.

**A. Additional evidence in the record confirms that state policy is not a threat to market integrity, providing further basis for revisiting, or at minimum, moderating the Commission’s approach.**

The Commission issued its finding that PJM Interconnection, L.L.C.’s (“PJM”) existing tariff is unjust and unreasonable or unduly discriminatory without evidence that the policies that allegedly threaten the integrity of the market actually result in the hypothesized “price suppression.” Recent PJM auction clearing results demonstrate that the anticipated price suppression has failed to manifest in spite of the absence of an expansive MOPR. As the Illinois

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2 Request for Rehearing of Clean Energy Advocates, ER18-1314 et al. (July 30, 2018).

3 Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act at P 64, ER16-49 et al. at PP 150-151 (June 29, 2018) (“Order”) (basing finding on assertion that out-of-market support “may allow” uncompetitive resources to submit low or zero-priced offers).
Attorney General points out, although the Illinois Zero Emissions Credit (“ZEC”) program has been operational since June 2017, prices in the ComEd zone have not been depressed relative to prices in other PJM areas.\textsuperscript{4} To the contrary, prices in the zone are higher than most other zones.\textsuperscript{5} This new evidence again indicates that the Commission’s vague theory regarding the impacts of state policy is wrong or, at least, far too simple to be useful in safeguarding the PJM market.

In addition, the Institute for Policy Integrity at New York University School of Law (“IPI”) provides evidence that, assuming government policies do result in price suppression, an expanded MOPR will not achieve the desired result of cancelling out impacts on the capacity market.\textsuperscript{6} As IPI explains, the over procurement that results from an expanded MOPR will cause suppression of energy market prices. Because the lowered energy market revenues means resources must recover greater shares of their expected going forward costs from the capacity market, capacity market prices will be higher than they would have been if there had been no government policy at all. In other words, the MOPR does not achieve the counterfactual that the Commission is aiming for: clearing prices will not reach the levels that the Commission theorizes would exist absent out-of-market payments.

\textbf{B. Substantial evidence demonstrates the high costs of over-mitigation.}

Even as arguments in support of an expanded MOPR weaken with further inquiry, the evidence regarding the costs of the MOPR continue to mount. In addition to the inefficiencies and

\textsuperscript{4} Initial Brief of the People of the State of Illinois, EL16-49 \textit{et al.} at 2-3 (Oct 2, 2018).

\textsuperscript{5} \textit{Id.} at 3, 8-9 (arguing Exelon has no incentive to adopt a bidding strategy that will result in a clearing price below a competitive price).

\textsuperscript{6} Comments of the Institute for Policy Integrity at New York University School of Law, EL16-49 \textit{et al.} at 12-13 (Oct. 2, 2018) (“IPI Comments”).
burdens of over-mitigation identified in our initial comments, IPI points out a host of other problematic impacts on market competitiveness that result from setting the MOPR floor too high. A high MOPR floor reduces the number of bidders offering below the floor. Market participants who are not subject to the MOPR know that they can submit offers up to the floor without competition from the resources subject to the MOPR. This reduction in competition exacerbates seller market power. In addition, even if resources subject to the MOPR remain in the market, the increase in the offers of the resources subject to the MOPR will change the opportunity cost of withholding capacity among resources that are not (making it more likely for high payoffs of such withholding). This, in turn, increases the ability to exercise market power and the risk of tacit collusion. Moreover, these impacts worsen the as the discrepancy between the MOPR floor and the true competitive bid grows. As numerous parties have pointed out, the history of MOPR shows that these administrative thresholds have not been set accurately, suggesting it is highly likely market administrators will fail at the task again. An expanded MOPR thus greatly increases the risk of harm to market efficiency and competitiveness due to inherent inaccuracies in MOPR reference prices.


IPI Comments at 7, 15-16.

Id. at 15-16.

Id. at 16.

See, e.g., Argument of the Organization of PJM States, Inc., EL18-178 at 12 (Oct. 2, 2018) ("[E]xperience in PJM’s Quadrennial Review process demonstrates that even use of PJM’s Net CONE value as a MOPR price will inflate market prices above the cost of new entry."); ELCON Comments at 4 ("[W]ithin PJM, many competitive capacity offers exempt from MOPR have come in at half or less the cost of new entry estimates in recent Base Residual Auctions.").
C. The Commission is opening a Pandora’s box by inviting scrutiny of any policy choice that affects revenue from secondary, non-jurisdictional products.

In addition to the growing evidence that expansive use of the MOPR is a worse threat to the market than the purported scourge of government policy, IPI points out that the Commission’s new paradigm focused on addressing the effects of out-of-market revenue on the capacity market will have a much broader sweep than perhaps originally anticipated.\textsuperscript{12} Indeed, by taking on the role of attempting to neuter government policies related to non-jurisdictional products, the Commission is opening up a veritable Pandora’s box of complexity.

The Commission’s Order focused on two kinds of “out-of-market support”—Renewable Portfolio Standard (“RPS”) programs that create demand for renewable energy certificates (“RECs”) and the ZEC program. Both programs create the institutional incentives for resources to receive payments for the value of the environmental services they provide. Yet these are not the only revenue streams generated from non-jurisdictional products that could plausibly impact resource bidding behavior and, potentially, market outcomes. As IPI explains, there are a number of out-of-market revenue sources that are in all relevant ways, “similar to revenue resources receive[d] through state RPS, ZEC, and renewable procurement policies.”\textsuperscript{13} Coal ash sales, steam heat sales, and certain emission allowances are all out-of-market revenues that predictably enable reduced offers and are incented or created by government policies.\textsuperscript{14} State policies, for example, can directly prohibit, enable, or create special incentives for the sale of coal ash products.\textsuperscript{15} A government coal ash policy thus can guarantee a certain class of generators an additional revenue stream that is not available to other resources, leading to what the Commission classifies as

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\textsuperscript{12} IPI Comments at 27.
\textsuperscript{13} \textit{Id}.
\textsuperscript{14} \textit{Id.} at 27-32.
\textsuperscript{15} \textit{Id.} at 27, n.86.
\end{flushright}
“uneconomic” bidding behavior that threatens the integrity of the market. If the Order is carried through to its logical endpoint, the Commission must also apply the MOPR to resources that receive these forms of government-enabled revenue streams to ensure that clearing prices are the product of competitive bids and that such out-of-market support isn’t allowing uneconomic resources to remain in the market.

The increasing breadth of the Commission’s role in policing offers into the Reliability Pricing Model (“RPM”) is concerning because there are real costs to this kind of administrative intervention in the markets. The costs of inoculating the market from the effects of government policy choices through MOPR rapidly outpace the benefits of administering the cure.

II. The Commission must navigate between Scylla and Charybdis: avoiding both over-mitigation and unprincipled line drawing in determining the scope of the MOPR.

As Clean Energy Advocates discussed in our opening comments, over-mitigation results in unjust and unreasonable rates. Indiscriminately applying the MOPR to every offer is destructive to the aims of the capacity market. At the same time, extending the MOPR to some forms of government support and not others without principled distinction runs afoul of the Federal Power Act’s prohibition on undue discrimination. Arbitrary application of the MOPR, particularly when paired with a punitive mechanism such as PJM’s Extended Resource Carve-Out (“RCO”),

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16 To continue his journey in Homer’s THE ODYSSEY, Ulysses was forced to navigate between two sea monsters, Scylla and Charybdis. Veering too close to either hazard would sink his ship and cost Ulysses and his crew their lives.

17 MOPR Comments at 13 (“As its north star, the Commission has strived to strike the right balance between over and under-inclusiveness.”); see also ELCON Comments at 3 (“Broad application of administrative fixes will undermine efficient entry and exit . . . and unnecessarily raise costs to consumers while deterring innovation and encouraging gaming.”).
can result in severe anticompetitive effects to targeted resources and unfairly harm customers. The task of the Commission, like Ulysses, is to steer a course between the twin perils.

In our opening comments, we advocated for a “right-sized” MOPR aimed at addressing incentives that are significant enough to have some likelihood of affecting market outcomes while incorporating sensible exceptions such as for competitive programs and small resources. We note that other commenters offered a similar perspective. We also criticized PJM’s proposal as failing to achieve that right balance; lacking a principled approach, PJM was both overbroad in some regards while arbitrarily excluding from scrutiny several significant categories of government incentive.

The following comments do not repeat concerns or observations raised in our initial filing. We instead address additional elements of PJM’s proposal set forth in its initial filing, including the heightened importance of avoiding arbitrary distinctions among resources affected by the MOPR in light of PJM’s RCO proposal. We also rebut arguments in support of the self-supply exemption, each of which would apply with equal force to the state climate policies targeted by the Commission’s Order. Finally, we note our support for PJM’s exclusion of voluntary RECs from the scope of an expanded MOPR, though the exemption does not go far enough and continues to over-mitigate resources that present no threat to the integrity of the market.

A. The inevitable result of an unprincipled definition of an actionable subsidy is undue discrimination.

Application of the MOPR in a discriminatory manner results in competitive disadvantage to the affected resources and harm to customers (and ultimately, other generators), who face the

18 MOPR Comments at 2.
19 See, e.g., ELCON Comments at 5 (the Commission “should limit the qualifying characteristics of an actionable subsidy only to the types and degrees of subsidization that fundamentally compromise competitive markets”).
costs of over procurement. Absent a principled distinction between government actions that are
deemed pernicious subsidies and therefore subject to the MOPR and those that are not, there is no
reasonable basis for such discriminatory treatment. Even when paired with a workable FRR
alternative that provides a reasonable means to recognize the contribution of FRR resources to
reliability, there are discriminatory impacts (e.g., transactional costs to negotiate a side deal for
payment outside of the market) to both the resources and, in turn, the commensurate load, that
result from participation in the FRR alternative. However, the potential for discriminatory impacts
become a much greater threat in light of PJM’s RCO and Extended RCO proposals. Both
proposals, though Extended RCO to a much greater degree, impose discriminatory treatment of
RCO resources compared to resources participating in the RPM, or even in the original FRR, and
we have urged the Commission to reject them in favor of our own workable proposal.20 In any
event, the sheer scope and scale of discriminatory effects under either of PJM’s proposals demand
that the Commission apply strict scrutiny to ensure that those impacts are falling justly. The FRR
alternative proposals under consideration in this proceeding thus only heighten the importance of
a well-reasoned, evidence-backed definition of the “actionable subsidy” or “out-of-market
remedy” that will trigger an expanded MOPR.

B. The self-supply exemption is arbitrary and discriminatory.

Our initial comments urged the Commission to reject PJM’s proposed self-supply
exemption. As the largest, most extensive source of out-of-market revenue, simply exempting this
category of government support defies the logic of the Commission’s Order. Proponents have
marshalled a series of arguments in support of the exemption. While we are sympathetic to the

20 See Clean Energy and Consumer Advocates Reply Comments in Support of FRR-RS,
EL18-1314 et al. (Nov. 6, 2018), filed contemporaneously in this docket.
concerns identified by those commenters, the reasons for excluding self-supply from the scope of the MOPR would apply with equal force to climate policies like the ZEC and state RPS programs. To the extent self-supply is granted an exemption, climate policies that aim at valuing environmental services must be granted one as well. We then sharpen focus on the sheer arbitrariness of such line-drawing by providing a concrete example of how, under such an exemption, the undisputedly uneconomic Ohio Valley Electric Company (“OVEC”) Clifty Creek and Kyger Creek coal units, which are more than 40 years old, would be deemed “competitive” participants in the market, as would a wind farm receiving RECs in Indiana (where the resource receives cost-recovery), but a wind farm receiving RECs in Maryland would not.

Self-supply proponents offer three main arguments for the exemption: the long-standing nature of the practice; the lack of intent to suppress capacity prices and legitimate purposes of the self-supply model; and that self-supply is not a form of “out-of-market payment.” None of these provides a rigorous basis for distinguishing self-supply, in which the ability of resources to recover their going forward costs is determined by the relevant regulator rather than the ability to clear in RPM, from other forms of government incentive.

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21 See e.g., Initial Submission of the National Rural Electric Cooperative Association, EL18-178 at 18, 25 (Oct. 2, 2018) (“NRECA Initial Submission”) (arguing Commission must exempt revenues consistent with “long-standing business models” of self-supply).


23 See e.g., APPA Initial Submission at 12 (“Payments from customers for self-supply resources are not ‘made or directed’ by a state in the same way as the ZEC and RPS programs”).
State renewable portfolio programs, too, are longstanding in nature and precede the inception of RPM. If the persistence of a practice is sufficient basis to warrant an exemption, then state RPS programs, too, must be grandfathered in.

Likewise, while we do not doubt that there are “benefits from assembling a portfolio of generation resources well beyond those available from the RPM capacity market” that drive public power and other entities to the self-supply model, rather than an intent to suppress market prices, the same is true of states adopting climate policies. If the legitimacy of the policy and the benefits it seeks to foster are sufficient grounds for an exemption, then neither ZECs nor RECs can trigger the MOPR.

Lastly, efforts to distinguish self-supply from other forms of government incentive are unavailing. For one, proponents’ submissions reveal that many of the resources participating in self-supply do, in fact, receive government incentives in a form that is traditionally considered a subsidy (i.e., a direct transfer of value from a government to a set of resources). In any event, to the extent providing a government incentive in a form other than a direct payout warrants an exemption, state RPS programs too must benefit. As described in our initial MOPR comments, state RPS programs generate demand for environmental attributes, and eligible resources do not have any guarantee of payment. By comparison, the guarantee of cost-recovery afforded to self-

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25 NRECA Initial Submission at 17.
26 See e.g., NRECA Initial Submission at 26 (“many cooperative utilities receive funding and hold debt from the U.S. Rural Utilities Service”).
supply resources is far more predictable, and therefore more likely to be linked to changes in bidding behavior that are the root of the Commission’s concern in this docket.

To demonstrate the arbitrariness of the self-supply exemption, it is worth considering two examples described in the comments of the Union of Concerned Scientists (UCS), and then further drawing comparison with the OVEC coal plants. UCS identifies two specific wind farms, one based in Indiana and owned or contracted for by a vertically integrated utility, the other is a merchant facility in Maryland. Both are eligible for, and in fact receive, RECs under state RPS programs. But with the self-supply exemption in place, the Indiana wind farm would be eligible for the self-supply exemption, because a division of AEP owns or has contracted for the Indiana wind farm’s output. In contrast, the Maryland wind farm would be subject to MOPR due to its receipt of REC revenues and lack of association with a self-supply LSE. No reasonable hypothesis can explain how the Maryland wind farm’s participation in RPM is a threat to the integrity of the market, but the Indiana wind farm’s participation is not.

Consider as another point of contrast with the Maryland windfarm, the aging and uneconomic OVEC coal plants. Although the Public Utilities Commission of Ohio has authorized retail rate riders for AEP subsidiaries to allow them to charge captive Ohio customers the difference between revenues received from their sales of capacity and energy into the PJM markets and their share of the costs of the plants, AEP and Duke argue that this government-induced

27 Comments of the Union of Concerned Scientists, EL18-178 at 4-6 (Nov 5, 2018).
28 Id. at 6-7
29 Id. at 6.
30 Comments to Protect Electric Consumers from Paying Subsidies in PJM Markets by the Office of the Ohio Consumers’ Counsel, EL18-178 at 21 (Oct. 2, 2018); see also Initial
support is not an “out-of-market payment[]” within the meaning of this proceeding. AEP and Duke argue that these payments “do[] not have the effect of preventing the retirement of the OVEC units” and are “not linked in any way to retirement or operation decisions of OVEC.” But there can be no doubt that, but for the guarantee of cost-recovery from retail authorities, these aging units would not recover sufficient revenue in the PJM markets to cover their going forward costs and would be forced to exit. Indeed, it is precisely this kind of failure of uneconomic resources to exit that is a central motivation of the Commission’s Order. The self-supply exemption arbitrarily obscures scrutiny of precisely the forms of government support that it considers a threat to the PJM market.

C. The economic development exemption is arbitrary and discriminatory.

PJM again proposes to exempt revenues “that are aimed at economic development through development grants, tax credits and the like” from the definition of an actionable

32 Id.
33 FirstEnergy Generation has sought as part of a pending bankruptcy proceeding to be relieved of its contractual obligations regarding the OVEC units, on the grounds that its mere 4.85% stake in those units will cost it to lose approximately $268 million over the next two decades. See Motion for Entry of an Order Authorizing FirstEnergy Solutions Corp. and FirstEnergy Generation, LLC to Reject a Certain Multi-Party Intercompany Power Purchase Agreement with the Ohio Valley Electric Corporation as of the Petition Date, Case No. 18-50757, ¶ 15 (Bankruptcy N.D. Oh. Apr. 1, 2018), available at: https://www.eenews.net/assets/2018/05/24/document_pm_02.pdf; see also Jeffrey Tomich, “Money pit or fuel hedge? In Midwest, it depends who’s paying”, E&E NEWS (May 25, 2018), https://www.eenews.net/stories/1060082697 (reporting on state-level disputes over cost recovery for the OVEC units that are widely recognized to be uneconomic).
34 See e.g., Order at P 154 (“older, uneconomic resources in PJM, which may not be able to clear the market based on their costs alone, are increasingly receiving out-of-market support to allow them to remain in the market”).
subsidy, and thus the scope of the MOPR.\textsuperscript{35} PJM offers no basis for concluding that these forms of government incentive do not affect substantial quantities of resource to a significant degree, and there is no basis in the record to conclude that these payments impact the market any differently than other forms of government support. Instead, PJM appears to base the exemption on the intent of the state or local government entity in granting it. As discussed above, if intent is a relevant basis for an exemption, climate policies, too, warrant exemptions. Moreover, as described at length in Clean Energy Advocates’ initial protest and the report of Doug Koplow, subsidy expert, these forms of government incentive are quite extensive in PJM and can be large in size.\textsuperscript{36} Thus, there is no reasonable basis for exempting economic development incentives from the definition of an actionable subsidy.

D. The exemption for voluntary RECs is warranted, but should be expanded.

PJM also proposed an exemption for one category of RECs, which we described as “voluntary RECs” in our initial comments. PJM describes this exemption as applying “to a purchaser that is not required by a state program to purchase the REC” and where there is no “state financial inducement or credit” for the purchase.\textsuperscript{37} Clean Energy Advocates support this exemption, for all the reasons provided in our initial MOPR comments. However, the exemption does not go far enough, as PJM would unreasonably continue to apply the MOPR to other forms of RECs. Moreover, the exception to the voluntary REC exemption is large enough to swallow the rule. PJM essentially proposes to presume that all sales of RECs through an intermediary are

\textsuperscript{35} Initial Submission of PJM Interconnection, L.L.C., EL18-178 at 23 (Oct. 2, 2018).
\textsuperscript{36} Protest of Clean Energy Advocates Protest, ER18-1314 at 85-87 (May 7, 2018) (“Koplow’s research provides only a sample of the kinds of programs likely to fall within this exemption, yet even that time-constrained review reveals numerous targeted subsidies to energy-related activities that exceed $20 million”); see also id. at Appendix B - Koplow Report.
\textsuperscript{37} Initial Submission of PJM Interconnection, L.L.C., EL18-178 at 24 (Oct. 2, 2018).
driven by RPS mandates, and would thus deem these sales to be a “subsidy.” Since the REC market in PJM is largely comprised of sales through intermediaries, the PJM proposed exemption would exclude very little of the REC transactions. Clean Energy Advocates continue to urge the Commission to adopt the more complete exemption for state RPS programs as set forth in our initial MOPR comment.

III. PJM’s Proposed MOPR Floor Is Inadequately Supported And Results in Over-Mitigation.

PJM proposes to screen new generation resources through reference prices meant to approximate the net cost of new entry (“CONE”) based on resource type. PJM’s attempt to estimate CONE for classes of resources not currently subject to the MOPR is thinly supported. Moreover, it is fundamentally misguided because it creates arbitrary distinctions between new and existing resources, leading to over-mitigation, barriers to new entry, and distortion of the capacity market. The Independent Market Monitor’s (“IMM”) suggested approach of basing the MOPR floor references prices for both new and existing resources on their net avoidable cost rate (“ACR”) would better accomplish the Commission’s goal of ensuring the competitiveness of the capacity market.

PJM’s CONE estimates for resources types that would be newly subject to the MOPR are thinly supported and contain a significant error. PJM’s proposal cites the NREL Annual Technology Baseline as the source of its costs data for renewable resources. Yet, as noted by UCS, that document contains numerous sets of location-specific project costs and performance parameters—including 15 sets of utility-scale solar numbers alone—and PJM provided no guidance as to which numbers it actually used to set the default MOPR floor prices for these
resources. The scant data PJM did provide on its calculation of default MOPR floor prices also includes a significant error: it provides identical values in Table 1 for energy and ancillary services (“E&AS”) revenue for onshore wind and offshore wind, which is not plausible given the different energy production profiles and locations of these technology types.

More fundamentally, PJM’s approach of applying estimated CONE to a host of new resource types creates an arbitrary distinction between new and existing resources. As the IMM notes, resources “enter and remain in the market with the expectation that they will recover their costs and earn a return on and of capital,” regardless of whether they are new or existing. Basing the MOPR floor for new resources on CONE while using the ACR for existing resources is arbitrary because the economic logic for both new and existing resources is the same. Moreover, handicapping new resources with a high CONE-based price floor has the perverse effect of disincentivizing the entry of efficient new capacity and artificially extending the life of less efficient older generation. Accordingly, if the Commission expands the MOPR, it should adopt the IMM’s reasoning regarding the MOPR floor and apply the ACR to both new and existing resources. This is because a “competitive offer in the capacity market is the marginal cost of capacity, or net ACR, regardless of whether the resource is planned or existing.”

CONCLUSION

Clean Energy Advocates respectfully submit these comments for the Commission’s consideration regarding the scope of an expanded MOPR.

38 Comments of the Union of Concerned Scientists, EL18-178 at 9 (Nov 5, 2018).
39 Id. at 9-10.
41 Id. at 17.
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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.


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Exhibit G
Reply Comments of Clean Energy and Consumer Advocates in Support of FRR-RS, November 6, 2018
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, et al.

v.

PJM Interconnection, L.L.C.

Docket Nos. ER18-1314-000

ER18-1314-001

EL16-49-000

EL18-178-000

REPLY COMMENTS OF CLEAN ENERGY AND CONSUMER ADVOCATES
IN SUPPORT OF FRR-RS


1 We use the terms “FRR alternative”; “resources-specific FRR”; and “resource-specific FRR alternative” interchangeably herein to distinguish from the “existing FRR” or the “original FRR” that is currently provided for in the PJM Interconnection, L.L.C. (“PJM”) tariff. Each of these terms is meant to encompass all versions of a resource-specific FRR alternative, rather than a specific proposal. When referring to the Clean Energy and Consumer Advocates’ particular proposal, we use the moniker “FRR-RS” throughout.
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SUMMARY OF ARGUMENT

The Commission’s proposal to develop a resource-specific Fixed Resource Requirement as an alternative means for states to procure capacity consistent with their environmental policy objectives, is sound and should be adopted. This record contains ample evidence that a bifurcated capacity market construct would provide accurate and adequate price signals in the centrally-cleared auction portion of the capacity market, while the resource-specific FRR would accommodate states’ and consumers’ desire to obtain capacity from resources that receive out-of-market revenues pursuant to state policies in a transparent and workable way.

Despite the Commission’s clear rejection of an expanded MOPR without any accommodation of state policy, numerous parties persist in advocating for an “all or nothing” Reliability Pricing Model (“RPM”) construct that forces states to forgo pursuit of their own policies—including the public health and environmental benefits of emissions-free generation—in order to participate in the capacity market. These parties portray any accommodation of state policy as necessarily resulting in “price suppression” in the capacity auction, even when those prices result from competition exclusively among generators without out-of-market revenues that PJM deems actionable. The flawed theory underlying the claims of price suppression in this context results simply from reduced demand for these generators’ product. That sellers in the auction market may now have fewer customers and be less able to charge the higher prices they would like is not unfair to those sellers—it reflects basic supply and demand fundamentals.

The Commission must reiterate its rejection of an expanded MOPR without accommodation of state policy resources. Such an approach would not result in just and reasonable rates and would lead to undue discrimination, forcing consumers to pay for unnecessary capacity while arbitrarily singling out some resources receiving out-of-market revenues.
compensation but not others. An expansion of the MOPR unaccompanied by a workable resource-specific FRR would not achieve the Commission’s goal of accommodating state policies and would produce inefficient over-mitigation. Moreover, it would baldly force customers to pay unnecessary costs and exacerbate PJM’s massive supply glut that suppresses energy market prices as well as clearly indicate that further measures to increase supply are not necessary. Mandating build out of unnecessary capacity on the backs of consumers would exacerbate existing problems within PJM and violate the Commission’s duty to ensure just and reasonable rates. An expanded MOPR that makes no accommodation for sponsored policy resources would be an arbitrary and unduly discriminatory exercise in line-drawing. Direct “subsidies” are far from the only state and federal policies that may affect a resource’s bid price in the Base Residual Auction (“BRA”)—tax burdens and credits, zoning laws, and policies supporting specific fuels all have undeniable effects on a resource’s ability to submit a bid at or below the clearing price. Yet an expanded MOPR would single out for mitigation just one policy lever favored by states seeking to address environmental externalities. Additionally, an unmitigated, expanded MOPR encompassing state policies would likely push states to achieve their goals through less efficient policy solutions.

The expanded MOPR would encompass policies fully within state authority and not preempted by the Federal Power Act. The state policies at issue do not aim to adjust energy or capacity prices, but rather aim to address externalities caused by power production. By mitigating resources supported by state policies, the Clean MOPR proposal would have the Commission second-guess and reverse state policy determinations about the value of externalities.
Fortunately there is a viable alternative identified by the Commission—the resource-specific FRR. By removing bids deemed as receiving out-of-market revenue from the RPM, while acknowledging the reliability services these resources afford the grid, the Commission achieves a reasonable balance across its goals of preserving the integrity of price signals in the competitive market, increased transparency for investors, consumers, and policymakers, and avoiding the double payment and over procurement problems that otherwise result from expanded MOPR. Clean Energy and Consumers Advocates’ Fixed Resource Requirement-Resource Specific (“FRR-RS”) proposal reflects a careful balancing of the key principles needed to make a resource-specific FRR work for all market participants.

There are undoubtedly many complex questions regarding how a resource-specific FRR should be designed to best advance the objectives that the Commission identified in its June 29 Order. In these reply comments, Clean Energy and Consumer Advocates respond to many of the general but misplaced concerns raised about a resource-specific FRR. Opponents wrongly argue that the Commission exceeds the scope of its section 206 authority by incorporating any measures into the replacement rate beyond an expanded MOPR, when section 206 in fact provides ample authority for the Commission to fashion a just and reasonable replacement rate. Opponents also erroneously claim that approval of any FRR alternative maintains the status quo simply because it may result in similar price outcomes, while ignoring the underlying mechanism by which those prices are reached. Next, opponents turn to hyperbolic prognostications that adoption of an FRR alternative will doom the competitive markets. These absurd scenarios are not grounded in reality, in which states face (under any alternative proposed) real costs to establishing and implementing the programs that would lead to resource participation in an FRR alternative. Other opponents of a workable FRR alternative assert that the FRR alternative allows
states to exercise of buyer-side market power, but fail to articulate how the Commission’s buyer-side market power doctrine applies where consumers are not making an offer into a market, but instead opting to purchase less from that market. Finally, concerns that an FRR alternative is incompatible with retail choice are based on unfounded assumptions about how the FRR alternative will work and these concerns can largely be addressed by providing states with adequate time to develop any new policies needed to protect competition at the retail level prior to implementing the MOPR and FRR alternative.

Next, these reply comments present the key advantages of the FRR-RS over PJM’s basic Resource Carve-Out (“RCO”) proposal. The FRR-RS proposal would require FRR-RS loads to procure reserves equal to the installed reserve margin, whereas PJM would require that such loads procure reserves equal to the reserve margin that actually clears RPM, despite the fact that this higher reserve margin is unnecessary to achieve the reliability target. The FRR-RS proposal also recognizes that the capacity value of resources should be calculated in the same manner, regardless of whether they sell their capacity through RPM or the FRR-RS, whereas PJM proposes without justification to reduce the capacity value of resources offering into FRR-RS. Next, the FRR-RS allows for more flexibility in how commensurate load is identified for FRR-RS resources so that load and capacity resources can negotiate compensation in advance of the auction, whereas PJM proposes an illogical mechanism to identify commensurate load that will serve as a barrier to use of the FRR-RS. PJM also proposes to restrict resources that have participated in FRR-RS from returning to RPM so long as they continue to receive a subsidy, which is unnecessary in light of the application of the MOPR to such resources. Finally, the FRR-RS proposal calls for a limited transition mechanism to give states time to update their statutes or regulations as needed to make use of the FRR-RS or protect retail competition; PJM’s
RCO includes no such transition mechanism and will therefore lead to unjust and unreasonable rates.

While PJM’s basic RCO proposal is generally responsive to the Commission’s request for input regarding a resource-specific FRR that accommodates state policy, PJM’s Extended RCO proposal inflicts excessive costs on load and carved out resources participating in RCO. By design, the proposal results in customers in PJM paying billions of dollars per year in excessive costs by ignoring the contributions RCO resources make to reliability. On top of the inflated prices, Extended RCO also imposes a second category of unnecessary costs on customers. The so-called “infra-marginal payments” are little more than a gratuitous consolation prize for resources that do not clear the auction. Extended RCO is not just and reasonable, imposing these steep costs without any corresponding return in value to customers. Extended RCO is so severe as to be unusable, and as a result provides no accommodation of state resource choices at all.

Extended RCO also results in incorrect price signals, fails to incent appropriate exit and entry, and will therefore lead to significant investor uncertainty. These consequences stem from the fact that Extended RCO, like the Repricing proposal already rejected by the Commission, results in a “clearing price that is disconnected from the price used to determine which resources receive capacity commitments.”\(^2\) Extended RCO also creates new problematic opportunities for gaming, and results in discriminatory impacts on RCO resources. For all these reasons, the Commission must reject Extended RCO.

Some parties have proposed completely different constructs for replacement rates, but none are capable of being adopted within this proceeding. One proposes to implement a two-

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stage auction mechanism similar to the Competitive Auction with Sponsored Policy Resources ("CASPR") proposal recently approved in ISO New England ("ISO-NE"). The CASPR construct resulted from an extensive stakeholder process aiming to address very different types of state policies in a system with many structural differences from PJM; as such, there is inadequate evidence in the record to determine whether the pivotal component—the substitution auction—would function at all in PJM. Exporting this untested construct to PJM without allowing for further development and refinement by PJM and its stakeholders would be extremely risky. The competitive “carve-out” auction outlined in the comments filed by the Maryland Public Service Commission, as supported by the Organization of PJM States, and the multiple comments suggesting that PJM implement a carbon price appear both appear facially promising, but they require further assessment in the form of stakeholder process. Ensuring just and reasonable rates, and respecting states’ role under the Federal Power Act, requires that any mechanism to accommodate state policy be fully developed and ready to implement before the minimum offer price rule is dramatically expanded.

ARGUMENT

I. The Commission must reject expansion of the MOPR without accommodation of state policy resources.

The Commission made a preliminary finding that a just and reasonable replacement rate for the PJM rate may include two elements: an expanded MOPR to “ensure that the rates for the unsubsidized resources in the capacity market are the result of competitive market forces,” and a resource-specific FRR alternative to “mitigate or avoid the potential for double payment and over procurement.”\(^3\) Although the Commission was clear that these two elements would work in tandem to address price suppression in the capacity market while respecting state policy

\(^3\) Id. at PP 157-160.
prerogatives, several commenters propose an alternative replacement rate consisting of an expanded MOPR only.  

These proposals are without merit. Such an approach would not result in just and reasonable rates and would lead to undue discrimination, forcing consumers to pay for unnecessary capacity while arbitrarily singling out some resources receiving out-of-market compensation but not others. Nor would a so-called “Clean MOPR” achieve the Commission’s stated goal of accommodating state policies. It would also result in unlawful over-mitigation by inevitably catching many voluntary renewable energy credit sales in the same net, despite the fact that these are not based on state policy. The Commission should summarily reject any proposed expansion of the MOPR that makes no accommodation for state policy resources.

A. **Forcing consumers to pay for duplicative capacity that is not needed to meet grid needs is not just and reasonable.**

A Clean MOPR would undoubtedly require customers to procure more capacity than necessary to meet the region’s reliability needs. As the Commission noted, “if PJM’s MOPR applies to state subsidized resources with few or no exceptions, and yet the states continue to support those resources, some ratepayers may be obligated to pay for capacity both through the state programs providing out-of-market support and through the capacity market.”  

Because the bulk of state policies targeted by an expanded MOPR have been adopted to address the urgent threat of climate change and to reduce dangerous pollution that harms states’ citizens and impacts quality of life, states are indeed likely to press ahead with their policies whether or not

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5 Order at P 159.
the affected resources clear in PJM’s capacity market, providing additional support to resources if necessary. A Clean MOPR would ignore the capacity value of state policy resources by design, leading to the construction of resources that are not necessary to maintain reliability at great cost to consumers.

Were the Commission to impose a broadly expanded MOPR without a resource-specific FRR alternative or another mechanism to accommodate state policy resources, the Commission would itself be imposing the costs of unnecessary duplicative capacity on customers. In regions with capacity markets, the Commission has assumed responsibility to “reflect[] the economic value of capacity reserves”6 in a manner that is consistent with the region’s installed reserve margin. In other words, the Commission’s task in regulating capacity markets is to “ensure that there is enough generation to reliably meet load” without “overcharging . . . customers for unnecessary capacity.”7 While the Commission has reasoned that sloping demand curves may be appropriate due to their ability to induce more efficient pricing than vertical demand curves designed to exactly hit the installed reserve margins, any additional reserves must be procured in a manner consistent with their true value to the system.8 By entirely ignoring perfectly good capacity, a Clean MOPR would deliberately skew the process and grossly overshoot the installed reserve margin without any assurance that customers would be receiving value for their money. The Federal Power Act’s requirement that rates be just and reasonable prohibits setting rules in such a manner that misses the mark by design.

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Some commenters suggest that the Commission has wrongly identified a double-payment problem arising from a Clean MOPR, and that the state’s choice is “akin to a choice between a basic healthcare plan and a ‘Cadillac plan’ with richer benefits: it is not a double payment to pay more for a premium plan with additional benefits.” The analogy is apt but misapplied. The effect of the MOPR is that the consumers in a state that have purchased the Cadillac plan must also purchase the basic plan in order to avoid Internal Revenue Service penalties for not having health insurance. The resource-specific FRR alternative is the mechanism that would allow customers to buy the Cadillac plan instead of the basic plan, rather than both. Nor are proponents of a clean MOPR correct in claiming that the courts have already held that consumers need never be protected from “having to pay twice for capacity.” The courts have never confronted a Commission decision that would force states to bear excessive costs of this scale. As the Commission indicates in the Order, it “has, in the past, found it acceptable or beneficial to avoid requiring customers to pay twice for capacity as a result of state policy decisions.” The staggering impact on wholesale market prices of a Clean MOPR and the absence of any pressing reliability need demand a similar conclusion here.

A Clean MOPR would baldly force customers to pay unnecessary costs and exacerbate the massive supply glut in PJM that suppresses energy market prices, and that clearly indicates further measures to increase supply are not necessary. Past Commission capacity market decisions focused on deterring the construction or retention of so-called “uneconomic”

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9 NRG Initial Brief at 12.
10 EPSA Initial Brief at 10. While EPSA cites Connecticut Department of Public Utility Control v. FERC, 569 F.3d 477, 481 (D.C. Cir. 2009) as holding that there’s nothing wrong with states “having to pay twice for capacity,” the court never used those words, but instead concluded that there was nothing wrong with states being forced to bear the costs of not allowing newer, more efficient units to be built.
11 Order at P 69.
generation,\textsuperscript{12} or preventing states from explicitly adjusting \textit{capacity} prices after the fact, thereby undermining the Commission’s ability to set prices.\textsuperscript{13} A Clean MOPR would constitute a drastic and misguided modification to the MOPR that is not supported by past precedent.

A “Clean MOPR” is fundamentally flawed because not only will it induce entry of more resources than warranted, but it also will set prices in a manner that does not provide adequate incentive for resources to exit the market in response to PJM’s glut of supply. Structural problems with PJM’s market have already encouraged a massive overbuild of the system at great cost to customers, and a Clean MOPR would make that problem far worse, taking the market in exactly the opposite direction from what is necessary. In short, mandating build out of unnecessary capacity on the backs of consumers would exacerbate existing problems within PJM and violate the Commission’s duty to ensure just and reasonable rates. Fortunately, there is a viable alternative, the resource-specific FRR alternative, that avoids the double-payment problem and can yield just and reasonable rates.

B. A “Clean MOPR” would unduly discriminate against resources receiving “subsidies” while ignoring other state and federal policies affecting capacity market bids.

Although styled as a “clean” and administratively simple policy, an expanded MOPR that makes no accommodation for sponsored policy resources would be an arbitrary and unduly

\textsuperscript{12} See New England Power Generators Ass’n, Inc. v. FERC, 757 F.3d 283, 295 (D.C. Cir. 2014) (“LSEs are free to shape their portfolios as they choose, including with new self-supplied resources, ‘provided these new resources clear the auction.’”) (emphasis added) (quoting ISO New England, Inc., 138 FERC ¶ 61,027 at P 74 (Jan. 19, 2012)). In fact, the particular buyer-side mitigation rules at issue in that case were designed to “prevent . . . excess capacity purchase.” \textit{Id.} at 293.

\textsuperscript{13} See New Jersey Bd. of Pub. Util. v. FERC, 744 F.3d 74 (3d Cir. 2014); Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1298-99 (2016) (holding that those programs functioned by modifying the capacity prices set by the Commission). In its underlying order, the Commission invited states to seek an exemption from the MOPR where the programs reflected the pursuit of “legitimate policy interests.” \textit{PJM Interconnection, L.L.C. & PJM Power Providers Group v. PJM Interconnection, L.L.C.}, 135 FERC ¶ 61,022 at P 143 (Apr. 12, 2011).
discriminatory exercise in line-drawing. Direct “subsidies” are far from the only state and federal policies that may affect a resource’s bid price in the BRA—tax burdens and credits, zoning laws, and policies supporting specific fuels all have undeniable effects on a resource’s ability to submit a bid at or below the clearing price. Yet an expanded MOPR would single out for mitigation just one policy lever favored by states seeking to address environmental externalities. While such discrimination might be acceptable if paired with a workable resource-specific FRR alternative that allows state policy resources to be compensated for the capacity they provide, a Clean MOPR that does nothing to ameliorate its effect on such resources would contravene the Federal Power Act’s prohibition on undue discrimination.14

Additionally, an unmitigated, expanded MOPR encompassing state policies would likely push states to achieve their goals through less efficient policy solutions. Renewable Portfolio Standard (“RPS”) programs and zero-emission credit (“ZEC”) policies are transparent in their aim to price environmental benefits. RPS programs, in particular, rely on competitive procurement, ensuring that climate goals are met through relatively transparent and efficient means. Were a Clean MOPR to be adopted, states could avoid mitigation by adopting less transparent and less efficient policies, relying more on siting, tax code, and other policy levers. Neither the market nor the public interests would be served should states be forced to rely on a narrower band of market interventions to achieve the same results.

14 See 16 U.S.C. § 824d(b) (“No public utility shall . . . (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.”)
C. A “Clean MOPR” would not accomplish the Commission’s stated goal of accommodating state public policies.

The Commission has made clear that a replacement rate for PJM’s capacity market should accommodate state policies. In contrast, a Clean MOPR is a direct attack on state policies because it does not have merely incidental effects upon the achievement of those policies, but rather aims to undo them. The expanded MOPR would encompass policies fully within state authority and not preempted by the Federal Power Act. The state policies at issue do not aim to adjust energy or capacity prices, but rather aim to address externalities caused by power production. By mitigating resources supported by state policies, the Clean MOPR proposal would have the Commission second-guess and reverse state policy determinations about the value of externalities. This is fundamentally beyond its competence and statutory role, and would transform the Commission into an environmental regulator, setting the stage for a future Commission to judge and mitigate for states’ failure to regulate externalities.

The Clean MOPR frustrates state policies by ignoring the capacity provided by cleaner resources whose viability depends on sales of their environmental benefits. Ignoring the contributions of state-supported resources forces state customers to rely on capacity from resources that do not earn revenue from state policies, essentially requiring state customers to procure a fixed amount of capacity from natural gas and coal-fired power plants. Reversing the state’s choice of generation mix in this manner “necessarily affects” the “construction” or retention of particular types of resources (those not receiving revenues pursuant to state policies

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15 See PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the Capacity Market, ER18-1314 at 4 (Apr. 9, 2018) (recognizing that “states rightly may pursue ‘various . . . measures . . . to encourage development of new or clean generation’” and making clear that PJM’s filing does not raise the question “whether states have the right to act”) (quoting Hughes, 136 S. Ct. at 1299) (emphasis omitted).
targeted by the MOPR), and is exactly the sort of “direct regulation of generation facilities” that the U.S. Court of Appeals for the D.C. Circuit stated the Commission would not engage in when approving the Commission’s authority to create capacity markets.\textsuperscript{16}

In essence, a Clean MOPR would force resources eligible for compensation under state policies to choose between availing themselves of those policies and participating in PJM’s capacity market. Far from accommodating state policies, a Clean MOPR would create an “all or nothing” RPM that forces states to forgo the benefits of those policies—including the public health and environmental benefits of emissions-free generation—in order to participate in the capacity market.

**D. The existing FRR construct cannot accommodate state policies.**

Several commenters point toward the existing FRR option in PJM as a solution to consider. These commenters range from American Electric Power (“AEP”) and Duke Energy, who remain neutral to the RCO concept but suggest that the existing FRR option be left as-is, to the PJM Power Providers Group, who suggests that the existing FRR (coupled with clean MOPR) is enough to accommodate state policies. The PJM Power Providers Group specifically claim that under the existing FRR, “any state can always elect to procure capacity on its own and, provided capacity performance obligations are met, pick the resources the state wants to provide its capacity and choose the means by which to pay for those resources.”\textsuperscript{17}

This perspective fails to accommodate state policies via a more tailored, resource-specific option as directed by the Commission. At a fundamental level, the existing FRR construct is all-or-nothing for load within a load-serving entity’s (“LSE”) service territory, such that the entirety of an LSE’s load must be removed from capacity market competition. This is ill-suited to address


\textsuperscript{17} PJM Power Providers Initial Brief at 13.
states where LSEs are likely to have mixed portfolios where only some of the generation sources are recipients of state support.

As explained by Buckeye Power, Inc., the current option also fails to meet the needs of LSEs in several other ways. Buckeye points out that the five-year commitment and prohibition on LSEs to offer residual capacity into the PJM market without being subject to a threshold or cap restrict the usefulness of the existing FRR option. The current FRR also does not let LSEs acquire capacity directly from the market to serve load in growth scenarios, which in turn can cause delays as capacity needs change over time.18

The American Public Power Association (“APPA”) has also previously commented on the challenges associated with the current FRR design, particularly for public power systems. In addition to noting the difficulty associated with geographic bounds under the current construct, APPA also cites year-to-year variability in capacity obligations, the inability to make residual capacity purchases in the wake of unforeseen issues like a major generator outage, the unavailability of bilateral contracts in capacity regions, disparate penalties, and restrictions on sale of excess capacity as barriers to workability of the current FRR for non-self-supply entities.19 Given this limited scope of applicability for the current FRR, the existing construct would not be able to accommodate state policy needs in areas not served by self-supply.

II. The Commission must reject PJM’s unworkable “Extended RCO” proposal.

PJM acknowledges that a “clean” Resource Carve-Out (“RCO”)—meaning one without repricing—affords “sufficient protection” to ensure just and reasonable outcomes.20

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19 Post-Tech Conference Comments of the American Public Power Association, AD13-7-000 at 6 (Jan. 8, 2014).
20 Initial Submission of PJM Interconnection, L.L.C., EL16-49 et al. at 64 (Oct. 2, 2018) (emphasis omitted) (“PJM Comments”).
Nevertheless, PJM presents the Commission with an “[e]xtended” version of RCO as an “option for the Commission’s consideration.”\(^{21}\) Other parties go further, arguing that a clean RCO is inadequate to meet the aims of this proceeding.\(^ {22}\) The Commission must reject Extended RCO. Extended RCO punishes, rather than accommodates, state policy choices by inflicting excessive costs on load and carved out resources participating in RCO. Extended RCO is so severe as to be unusable, and as a result provides no accommodation of state resource choices at all. This proposal thus fundamentally fails to meet a core element of the Commission’s Order.

Extended RCO, which is little more than a rebranding of the original repricing scheme, also suffers from many of the same fatal flaws as the Repricing proposal already rejected by the Commission. Like the original Repricing, Extended RCO results in a “clearing price that is disconnected from the price used to determine which resources receive capacity commitments.”\(^ {23}\) The price disconnect again results in incorrect price signals, fails to incent appropriate exit and entry, and will therefore lead to significant investor uncertainty. By design, the proposal results in customers in PJM paying billions of dollars per year in excessive costs by ignoring the contributions RCO resources make to reliability. On top of the inflated prices, Extended RCO also imposes a second category of unnecessary costs on customers. The so-called “infra-marginal payments” are little more than a gratuitous consolation prize for resources that do not clear the auction. Extended RCO is not just and reasonable, imposing these steep costs without any corresponding return in value to customers. Extended RCO also creates new problematic opportunities for gaming and results in discriminatory impacts on RCO resources.

For all these reasons, the Commission must reject Extended RCO.

\(^{21}\) Id.

\(^{22}\) See, e.g., NRG Initial Brief at 33-35.

\(^{23}\) Order at P 64.
A. Extended RCO does not meet the minimal requirements of the Order.

The Commission’s Order set forth a two-part directive.24 The first element of the proposed replacement rate is to expand MOPR in order to address the market impacts of out-of-market payments. The second element is to “accommodate resources that receive out-of-market support, and mitigate or avoid the potential for double payment and over procurement.”25 The Commission included the second element of the replacement rate because it “do[es] not take . . . states’ right to pursue valid policy goals . . . lightly.”26 A replacement rate that fails to accommodate state policy resources, does not address the likelihood of double payment, or continues to result in over procurement does not meet the objectives of the Order. Extended RCO does not meet the minimal requirements of the Order because it is an accommodation of state policy resources in name only. By imposing punitive costs on the states and resources that avail themselves of the resource-specific FRR alternative, the mechanism becomes unworkable, will not be used, and will fail to achieve any of the outcomes the Commission seeks to achieve.

1. Extended RCO does not accommodate state policy.

While ostensibly PJM aims to provide a pathway for state-supported resources to have their contribution to system reliability recognized without bidding into the market, the costs of participating in Extended RCO are so high as to make it unusable.

Any state that facilitates resource participation in Extended RCO will necessarily see capacity prices rise dramatically, and ultimately end users in the state will pay more in their energy bills. This is a design objective, not a bug, of the two-stage construct, in which the clearing price is set in the second stage without subtracting out the load that is being served by

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24 Id. at P 158 (“[T]here are two aspects to our proposed replacement rate.”).
25 Id. at P 160.
26 Id. at P 159.
RCO resources. Even under modest assumptions about the scope of the MOPR (which determines the potential quantity of resources that will participate in Extended RCO), the additional costs reach in the billions of dollars.\(^{27}\) As discussed in the next section, these excess costs are not just and reasonable. In addition, forcing states to choose between pursuing legitimate policy goals and exposing their residents to billions of dollars in unwarranted charges is punitive and the opposite of “accommodating” state prerogatives. Faced with this unacceptable choice, states may well come to view re-regulation as the only viable option.

Extended RCO also fails to accommodate state policy because it provides many potentially eligible resources little incentive to use it. All of the policies PJM identifies as likely “actionable subsidies” are programs to value resource environmental attributes: RPS programs, Renewable Energy Certificates (“RECs”), and ZEC programs. To meet its objectives, Extended RCO must be useful to renewable resources that are most commonly supported by such state programs. Renewable technologies, due to market rules outside the scope of this proceeding, already face significant barriers to participation in PJM as capacity resources.\(^{28}\) Capacity performance poses the risk of significant penalties during performance assessment hours, while seasonal resources face substantial transaction burdens to offer an annual capacity product. Resources must receive enough revenue in return to justify the financial risks and costs of securing a capacity obligation. Yet under extended RCO, PJM places another significant cost on

\(^{27}\) Reply Affidavit of James F. Wilson in Support of the Reply Comments of Clean Energy and Consumer Advocates, attached hereto at Exhibit A (“Wilson Aff.”), ¶ 67-73, Table 2.

\(^{28}\) See, e.g., Newell et al., Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM, The Brattle Group at 4-7 (Apr. 12, 2018), http://files.brattle.com/files/13723_opportunities_to_more_efficiently_meet_seasonal_capacity_needs_in_pjm.pdf (finding many seasonal resources are undervalued or excluded from the market); see also Transcript of PJM Seasonal Capacity Technical Conference, EL17-32 at 140 (Apr. 24, 2018) (discussing barriers to entry to renewable energy technologies).
resources participating in the FRR alternative. The “infra-marginal” consolation payments provided to resources that do not clear in the first stage of the two-part auction are charged to resources participating in RCO. While the consolation payouts are smaller in the aggregate than the costs of repricing (costing millions rather than billions in extra costs), these payments are likely to be significant to the economics of individual RCO resources. Being forced to pay out the profit another generator would have made in the market is likely to shift obtaining a capacity obligation from a narrow economic gain into a loss for some resources.\(^{29}\) If the prospect of gaming is added in, in which market actors have an incentive to ensure the delta between the inflated, second stage clearing price and the so-called “infra-marginal” unit’s offer is as large as possible, the consolation payment will be even larger and more eligible resources will conclude that participation in Extended RCO does not make financial sense. Because participating in the mechanism is not economic for a large category of resources intended to use it, Extended RCO is little better than no FRR alternative at all. Extended RCO thus also fails to achieve the Commission’s aim to address the double payment and over procurement problems caused by the expanded MOPR.

2. **Extended RCO is not justified by concerns about price suppression.**

In spite of its acknowledgement that a clean RCO is just and reasonable, PJM urges the Commission that Extended RCO will “protect capacity clearing prices from the effects of

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\(^{29}\) PJM appears to imagine that RCO resources are receiving all or most of their going forward costs from state programs, such that the resource is indifferent to whether it receives any other source of payment for its services. This is not how RPS programs work. Because almost all RPS programs entail some degree of competition, REC prices are driven low by competition, and in any event, RECs represent only a small share of the potential revenue a renewable resource could earn. Thus, the payments that are tied to a state mandate are not sufficient to support entry into the capacity market (and additional payment is needed for it to be in the resource’s financial interest to participate in the market).
awarding capacity commitments to uneconomic resources.” Absent the repricing and other elements of Extended RCO, clean RCO “would have the same economic effects (price suppression and resource substitution)” as permitting a state-supported resource to bid in as a price-taker. This is simply a softer version of the arguments offered by a number of generation owners, who contend that no version of the FRR alternative is just and reasonable because it is no better than the status quo. As addressed at length in section III.B, both PJM and the generation owners’ claims of price suppression are without merit. The Commission has never held sellers are entitled to anything more than an opportunity to recover their costs—not a guarantee of a particular price, a particular-sized market, or sufficient demand to meet revenue expectations. Meeting reliability requirements through an alternate mechanism is “price suppressive” only if market participants are entitled to expect all load in PJM to satisfy reliability through RPM. To the contrary, these cries of price suppression are inconsistent with early Commission precedent holding that the RPM is not the only just and reasonable means to satisfy capacity obligations.

**B. Extended RCO is not just and reasonable.**

The Commission concluded that PJM’s previous Repricing proposal was not just and reasonable due to a series of flaws. While PJM claims that its new repricing scheme is “designed to address the Commission’s concerns,” even superficial review shows that Extended RCO suffers from many of the same failings. In fact, there is only one significant difference between the two proposals: under Repricing version 2.0, unlike the original, RCO resources do not

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30 PJM Comments at 64.
31 *Id.* at 65 (quoting Affidavit of Hung-po Chao, ¶ 9).
32 See infra section III.B.
33 PJM Comments at 10.
34 Wilson Aff., ¶¶ 53-55.
receive compensation within RPM based on the inflated clearing price. PJM makes much of this “new feature,” as a safeguard to ensure RCO resources do not receive a “windfall.”³⁵ This single adjustment, however, does not negate that the core of both Repricing and Extended RCO is to disconnect the clearing price from market supply and demand fundamentals. This flaw alone is significant enough to warrant rejection of Extended RCO, as the capacity market cannot achieve the central objective of ensuring reliability at a just and reasonable cost where prices do not send correct signals.

Multiple compounding flaws provide further grounds to reject Extended RCO. Extended RCO results in higher prices than are necessary to meet reliability needs, forcing customers to pay billions of dollars more for no incremental benefit to reliability. The payouts to resources that do not even receive an obligation to provide capacity to PJM, while smaller in the aggregate than the costs of repricing, are even more outrageous on principle. Customers are literally handing over money for nothing when they pay for a project that assumes no obligation to serve them. Finally, these payouts, which come with no strings attached, provide a significant opportunity for gaming that could exacerbate the impact on customers.³⁶ The Commission must reach the same conclusion it did in reviewing the original repricing proposal: Extended RCO is not just and reasonable.

1. **Extended RCO sends incorrect price signals.**

   In its Order, the Commission explained its rationale for concluding the original Repricing proposal is unjust and unreasonable:

   PJM’s Capacity Repricing proposal would . . . disconnect the determination of price and quantity – a vital market fundamental. We agree with intervenors that, by setting a clearing price that is

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³⁵  PJM Comments at 10.  
³⁶  Wilson Aff., ¶¶ 59-64.
connected from the price used to determine which resources receive capacity commitments, the market clearing price under Capacity Repricing will send incorrect signals, leading to greater uncertainty with respect to entry and exit decisions.37

Yet this price “disconnect” is precisely the outcome of Extended RCO, again leading to incorrect price signals.38 In the first stage of Extended RCO, PJM would run the auction to determine which resources obtain capacity obligations. The first run would include RCO resources that are later carved out for the purposes of financial settlement. In the second run, however, PJM would ignore the contribution of RCO resources to serving load and set the price based on the offers of extra-marginal resources that are not, in fact, needed to meet demand. As in the original Repricing, “the higher price—created by repricing—would signal that the market would buy capacity from higher cost resources than actually clear the market and receive capacity commitments.”39 And the consequences of Extended RCO are just as troubling as the Commission found the effects of Repricing to be:

This would make it more difficult for investors to gauge whether new entry is needed, or at what price that new entry will clear the PJM capacity market and receive a capacity commitment. Market participants would see the final, second stage clearing price, but would have limited information on which resources received commitments and the first stage price.40

Under Extended RCO, market participants would see a price that signals a need for entry that is not reflected in the true market fundamentals. In fact, a portion of load is being served by state-supported resources; pretending otherwise only produces confusion and ultimately undercuts confidence in the market.

37  Order at P 64.
38  Wilson Aff., ¶¶ 53-55.
39  Id. at P 65.
40  Id.
2. Extended RCO results in punitively high costs for customers in states relying on RCO.

The Commission’s core statutory duty under the Federal Power Act is to protect consumers.\(^41\) The Commission has long held, and a rich body of caselaw affirms, that ensuring just and reasonable rates entails balancing investor and customer interests.\(^42\) “[P]rotecting consumers from overpaying for . . . capacity” is central to striking the right balance.\(^43\) Extended RCO does not protect customers from overpaying for capacity. Indeed, that is its defining feature. There are two separate elements of Extended RCO, each of which results in customers overpaying for capacity services. The first, repricing, imposes the largest cost on customers and is described in this section. The second, the misnamed “infra-marginal payment” that we refer to for clarity as the “consolation prize” or “consolation payout,” is addressed in the following section. Both, together, result in punitively high costs for customers in states that use the FRR alternative under Extended RCO.


\(^43\) New England Power Generators Ass’n, Inc., 146 FERC ¶ 61,039 at P 52.
PJM acknowledges that RCO resources “will be treated as if it has a capacity commitment and will be expected to perform as a Capacity Resource in PJM’s markets.” RCO resources are serving the reliability needs of the grid on an equal basis with resources that clear through RPM. Extended RCO, however, sets clearing prices as though RCO resources were providing no service at all to the PJM region. This has the direct and intended effect of overcharging customers in two ways. First, customers pay a price based on extra-marginal offers (what PJM confusingly call “infra-marginal” resources, but which are only infra-marginal in an alternate reality in which load is not being served by state-supported resources). By definition, customers are receiving the same reliability service at a higher price. Second, customers will pay for duplicative capacity because the false, high price signal will attract entry that is not, in fact, needed to meet system needs. The scale of the overpayment will vary depending on the quantity of resources participating in RCO (which in turn depends on the scope of the MOPR, which is still subject to final determination) and may lessen over time as the artificially high prices incent further excess capacity to enter the market. But under any scenario, the costs are steep.

The Independent Market Monitor ("IMM") analyzed the short-term effect of Extended RCO on clearing prices and the total cost increase compared to a baseline of the actual results under existing market rules. The IMM assessed a scenario in which about 23,700 MW of capacity participates in the FRR alternative under Extended RCO. While this scenario is likely an overestimate of the quantity of resources that would be subject to the MOPR and eligible for

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44 PJM Comments at 63.  
45 See Wilson Aff., ¶ 54.  
RCO under PJM’s expanded MOPR, it is not an unreasonable projection if there is no self-supply exemption to the MOPR (which would affect about a quarter of capacity in the market). The IMM found Extended RCO would result in a 67.6 percent increase in regional transmission organization ("RTO")-wide price, at $234.67 per MW-day.\textsuperscript{47} The Locational Deliverability Area ("LDA") prices also saw price increases, ranging from 20 percent to over 200 percent.\textsuperscript{48} In total, customers in PJM would pay more than $8 billion, an approximately 90 percent increase, in overpayments for capacity.\textsuperscript{49}

Even under scenarios that assume a more moderate quantity of capacity is subject to MOPR and eligible for RCO, the increased costs are excessive. Economist James Wilson analyzed the potential price increase under a scenario in which 5,000 MW participates in RCO, and found the additional annual costs to customers RTO-wide reached over $2 billion.\textsuperscript{50} A third separate analysis, using a scenario of 3,700 MWs of RCO capacity, also concluded that the overpayments under Extended RCO would cost customers billions of dollars every year.\textsuperscript{51} Northbridge Group director Michael Schnitzer estimated prices increases would result in $2.2 – 2.6 billion in costs per year.\textsuperscript{52}

PJM can make no serious argument that repricing and the resulting overpayment for capacity have any effect on grid reliability, and offers none. Remarkably, PJM’s affiant and Chief Economist, Dr. Hung-po Chao, declines to offer any argument in support of extended RCO, endorsing the proposal only “to the extent the Commission finds that [the RCO], standing

\textsuperscript{47} Id.
\textsuperscript{48} Id.
\textsuperscript{49} Id.
\textsuperscript{50} Wilson Aff. at Table 2.
\textsuperscript{51} Reply Brief of Exelon Corp., EL18-178, Declaration of Michael M. Schnitzer ¶ 15 (Nov. 6, 2018).
\textsuperscript{52} Id.
alone, would have unacceptable adverse effects on wholesale capacity market.”

Customers are not paying for improved reliability, or some other trade-off in market performance. Instead, PJM views Extended RCO as a means to address the fact that allowing state-supported resources to satisfy part of the underlying demand for resource adequacy that would otherwise be met by the auction means that some state-supported resources will displace resources that would have been selected by the RPM. Extended RCO aims at this “displacement” effect. In backing RCO as a just and reasonable replacement rate but offering Extended RCO as an alternate option, PJM puts the decision to the Commission of whether fairness demands paying out resources that make less profit because states (demanding products other than the capacity-only offered in RPM) are turning to resources outside the market.

But the Commission has already clearly reached an answer to this question. As the Commission explained in 2009, “RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers.” Prices must be “sufficient to retain existing efficient capacity,” but the aim is “ensur[ing] reliability” not ensuring stable profits. The notion that sellers are entitled to their expectations that demand for their capacity product will remain high, and, accordingly, their expectation of profit met, is absurd. Indeed, Commission endorsement of such a notion would contravene not only its 2009 order, but also the decades of precedent holding that what is “just and reasonable” must balance investor and customer interest. Such a profit guarantee dispenses with any notion of balance and would

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53 PJM Comments, Affidavit of Hung-po Chao, ¶ 1; see also Wilson Aff., ¶ 50.
54 PJM Comments at 65.
55 Id.
eviscerate the protection of consumers from excessive rates. The Commission must deny this distortion of the Federal Power Act’s legal standard, and firmly reject Extended RCO.

3. **Forcing customers to pay a consolation prize to resources that have no obligation to serve them is not just and reasonable.**

   Extended RCO has a second component that is not just and reasonable. PJM proposes that units that do not clear be paid the profit they would have earned as though they had cleared in the auction (a consolation payment). Units eligible for these consolation payments do not clear in the first stage of the auction, and therefore do not obtain a capacity obligation, but do clear in the second stage when RCO resources are removed (but not the commensurate load they serve). Because these units do not obtain a capacity obligation, they face no expectation to perform as other capacity resources in PJM. PJM proposes to charge the costs of these consolation payments pro-rata, based on MWs of capacity, among all resources participating in RCO. Ultimately, these costs will pass through to load served by RCO resources. Inexplicably and outrageously, PJM is asking customers to pay resources something for—quite literally—nothing.

   PJM’s explanation of the rationale underlying these payouts reveals that they are intended to punish states for pursuing legitimate policies, rather than enhance market function. Two theories, described by PJM’s affiant, Dr. Chao, motivate the consolation payouts. The first is that substitution of a market-preferred resource with one the market would not have selected can reduce the “social benefits” generated by the market. The second is that payments from the substituting resource to the resource that has been substituted are warranted as a form of “tradable right.” Both theories fall apart under scrutiny, are contradicted by PJM itself in

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58 PJM Comments, Affidavit of Dr. Hung-po Chao, ¶ 12.
59 *Id.* ¶ 15.
places, and boil down to little more than an unfounded judgment that state policies are inefficient and should therefore be deterred.

Under the first theory, PJM and Dr. Chao describe the payments as accounting for the “dead-weight loss” that results from uneconomic offers by state-supported resources.60 Chao claims that substituting a state policy resource “imposes costs because it will tend to cause the capacity market outcome to deviate from equilibrium where the market surplus is maximized.”61 Yet even Chao recognizes this is too sweeping a generalization, and that the effect of government policy is not always a “distortion” leading to “dead-weight loss”:

[E]conomic theory distinguishes among types of divergences between marginal private costs and marginal social costs. If a marginal divergence is caused by a market imperfection or externality of some kind then it is not considered a distortion.62

It is undisputed that the very policies PJM targets as “subsidies” aim to address environmental externalities that are not reflected in the market—precisely the case, as helpfully explained by PJM’s Chief Economist, where economic theory recognizes that deviating from the market outcome leads to an increase in social welfare, not a loss. The dead-weight loss theory provides no justification for a payout from a social welfare-maximizing resource (i.e., a resource that does not contribute to a socially costly externality, such as a zero-emissions renewable resource) to a suboptimal one (the “older, less efficient” resources that are likely to be displaced by resources participating in RCO63). Blanket statements that the targeted state policies reduce social benefits are not supported by sound economic theory, and are simply veiled assertions that the states are

60 *Id.* ¶ 14.
61 *Id.*
62 *Id.* ¶ 5.
63 PJM Comments at 74 (describing the resources likely to receive the so-called infra-marginal payments).
adopting bad (or sham) policies that do not achieve their legitimate aims of addressing environmental externalities.

The alternate theory for the consolation payments is no more convincing. Dr. Chao argues that, even though the resources receiving the consolation payments are not providing any service to the grid, these resources are owed the profit they would have received as “tradable rights.”64 The concept appears to refer to the ability of one market participant who has obtained a legal right to an asset (including intangible ones, such as a transmission right) to freely trade that asset to another market participant. Enabling such free exchange “foster[s] efficiency and innovation.”65 The disconnect arises with the notion that resources that did not clear and do not obtain a capacity obligation possess a right to the profit earned by serving the capacity market, and the fiction that the RCO resource is “freely” trading to obtain that vested right. The Commission has never viewed an investor/developer as entitled to something simply for putting in an offer.66 This radical theory would have sweeping, harmful implications for consumers. It would demand a payout anytime a shift in policy results in a resource losing its market share to a competitor; it would build in expectations that market rules could not change without substantial transfers from the winners to the losers. Such a bizarre tradable right theory defies the Commission’s judgment that the PJM market rightly aims to achieve the correct price signals, not revenue guarantees for developers. It is irreconcilable with the Commission’s statutory duty to provide just and reasonable rates that strike the right balance between consumer and investor interests, and must be rejected.

64 PJM Comments, Affidavit of Dr. Hung-po Chao, ¶ 15.
65 Id.
66 Wilson Aff., ¶ 57 (“I am not aware of any auction, market, or market-like mechanism where such payments are available.”).
Finally, the extent to which PJM’s case for these consolation payouts is internally contradictory and unconvincing is laid bare in its attempt to claim that such payments improve price signals. PJM, maddeningly, claims that making these consolation payments with no strings attached “sends an important additional signal” that “it’s time to consider retirement.”\(^67\) While PJM convincingly explains that resources eligible for consolation payments are likely to be “older, less efficient resources” that “are at risk of becoming uneconomic as newer, more efficient, lower-cost resources continue to come on line,” the perverse incentive created by the payout would be to remain in the market, with the chance of obtaining yet another consolation prize of profit in the next BRA.\(^68\) Isn’t the best signal that it’s time to retire not to receive any payout from the capacity market at all?

4. **Paying out a consolation prize incents harmful gaming.**

PJM points to its consolation payment as “align[ing] the price signals and incentives” of resources bidding into the auction.\(^69\) While the payouts may address some of perverse incentives created from a two-stage auction that disconnects the price run from obtaining a capacity obligation, it generates a slew of new perverse behaviors that harm market function and customers. As economist James Wilson explains, the proposed tariff would allow the following categories of resources to receive payments:

1. Resources that intend to retire before the delivery year, and participate in the RPM auction only to receive the [consolation] payment with no intention to provide service.
2. Planned resources that are eligible for the delivery year, but the developer has no intention to actually build the resource in time. A developer can, in fact, offer the same resource year after year, receiving [consolation] payments and never beginning construction.

\(^{67}\) PJM Comments at 74.
\(^{68}\) Id.
\(^{69}\) Id. at 73.
3. Resources that clear in later Incremental Auctions for the same delivery year. Such resources would earn both the [consolation payment] and also the RPM price from the incremental auction.\(^{70}\)

Extended RCO thus has the perverse effect of financing windfall payouts to retiring plants; ghost development projects that never get built; and double payments to resources.

Furthermore, market participants with market power and large portfolios will have the “ability and incentive to bid high, in order to economically withhold from the second stage of the auction resources that they do not expect to clear in the first stage” in order to raise prices paid to other resources in the portfolio.\(^{71}\) PJM’s Extended RCO would exacerbate the already problematic abuse of supplier market power within RPM.

C. Extended RCO is unduly discriminatory.

The Federal Power Act “fairly bristles with concern for undue discrimination.”\(^ {72}\)

Section 205(b) of the Act is unequivocal:

> No public utility shall . . . (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.\(^{73}\)

Under section 206 of the Federal Power Act, the Commission bears a statutory responsibility to protect customers and other market participants from undue discrimination.\(^{74}\)

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\(^{70}\) Wilson Aff., ¶¶ 59-64.

\(^{71}\) Id. ¶ 63.

\(^{72}\) Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987) (describing provisions of the Natural Gas Act that parallel provisions in the Federal Power Act)

\(^{73}\) 16 U.S.C. § 824d(b).

Extended RCO, by virtue of its punishing impacts on both resources participating in RCO and customers paying for load through RCO, is unduly discriminatory. First, Extended RCO produces anti-competitive effects that harm the ability of a resource participating in RCO to earn a fair return on investment, compared to resources participating in either RPM or the original FRR. Second, Extended RCO arbitrarily forces customers within RCO states to pay significantly higher costs for the same reliability service, compared to other customers within PJM. These discriminatory effects only become more acute when paired with an expanded MOPR that arbitrarily covers some forms of government-provided support and not others. Given the tremendous challenge in drawing principled lines around what is and is not a potentially distorting “subsidy,” it becomes highly probable that Extended RCO’s discriminatory treatment is unjustified across classes of resource and customer.

As described above in section II.B.3, resources that participate in RCO must bear the cost of the so-called infra-marginal payment under Extended RCO. The cost to an individual resource is significant, at about $15 per MW-day under a scenario with low (3,000 MW) participation in the FRR alternative or reaching more than $30 per MW-day under a moderate (5,000 MW) scenario. A RCO resource’s sale of capacity is devalued by the amount of this payment, resulting in a significant competitive disadvantage compared to resources not participating in RCO. On average, RCO resources will be less likely to be able to compete, receive a fair rate of return, and remain economic due to these charges. This competitive disadvantage is even more stark compared to the capacity resources that receive the so-called infra-marginal rent payments. These resources receive revenue, despite having no capacity obligation, whereas the RCO resource must incur a cost at the same time it takes on an obligation.

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75 Wilson Aff., ¶ 75, Table 2.
PJM, perhaps, would contend that this discriminatory treatment is warranted by the RCO resource’s receipt of a “material subsidy.” Clean Energy and Consumer Advocates dispute that receiving payments for environmental services justifies differential treatment, in the same manner that receiving revenue for other secondary, non-FERC jurisdictional products would not warrant disadvantageous treatment in RPM. But even setting that point aside, RCO resources clearly face undue disadvantages when compared to traditional FRR resources. RCO resources are in all relevant ways similarly situated to resources participating in FRR. Neither RCO nor FRR resources submit offers into RPM that affect clearing prices. Both RCO and FRR provide alternative means to meet reliability requirements and therefore have the incidental effect of reducing the size of the RPM (i.e., shift the demand curve). Under the FRR-RS proposal, RCO resources’ contribution to reliability in PJM is equal to resources in the original FRR. Yet, unlike those participating in the original FRR, RCO resources must payout at least $15 to $30 per MW-day to resources that do not contribute to system reliability. There is no justification for this discriminatory treatment.

Customers, too, face discrimination under Extended RCO. Removal of RCO resources without the commensurate load in the second stage of the auction results in large price increases, and these increases are not evenly distributed. In LDAs where resources are deemed to be subject to “actionable subsidies” and therefore participate in RCO, customers will predictably

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76 As discussed in section III.F.1, PJM proposes to place more onerous requirements on load served through RCO without justification. Thus, under PJM’s proposal, RCO resources would provide an even greater margin of reliability service to the region than resources in the original FRR.

77 See, e.g., IMM Brief at Attachment A, Table 16 (showing highly variable price effects across LDAs due to repricing, ranging from a 10 percent decrease to a 30 percent increase in clearing prices).
face higher prices compared to LDAs that do not contain such resources. While we contend that customers in states with clean energy policies ("actionable subsidies") do not deserve to face such targeted price hikes, the Commission need not agree with us on that point to recognize that Extended RCO will have discriminatory impacts. Because it is exceedingly difficult to draw a principled line around government actions that are "subsidies" and those that are not, it is highly probably that any definition of subsidy will lead to arbitrary distinctions among customers that are similarly situated. Under a workable FRR alternative that reasonably accommodates state policies, these distinctions have far less consequence. But under Extended RCO, drawing the line wrong could, for example, stick some customers with an outrageous near doubling of their capacity costs, while other customers, who are in all relevant ways the same as the first group, do not see prices change significantly. The latter group of customers may avoid these substantial increases in cost because, for example, a state policy within their jurisdiction falls on the right side of an arbitrary threshold to be actionable (e.g., affects less than one percent of expected revenues and is not material), or is located within the same state but in a different capacity zone. In any event, the dramatic difference in treatment of the two customers cannot be justified. Rejecting Extended RCO ensures that customers do not face the likelihood of undue discrimination.

III. The Commission should adopt Clean Energy and Consumer Advocates’ FRR-RS proposal as a workable alternative.

The Commission has a viable option, supported by the record before it, that meets the objectives laid out in its Order. The Clean Energy and Consumer Advocates’ FRR-RS proposal

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78 Clean Energy Advocates described the likelihood of this occurrence in our initial protest. See Clean Energy Advocates Protest, ER18-1314 at 91-92 (May 7, 2018); see also Affidavit of James F. Wilson in Support of the Protests of PJM Consumer and Environmental Intervenors, ER18-1314, ¶ 78 (May 7, 2018).
reasonably accommodates state policies while addressing the Commission’s concern about the effects of out-of-market revenue on bids into the capacity market. By removing bids deemed as receiving out-of-market revenue from the RPM, while acknowledging the reliability services these resources afford the grid, the Commission achieves a reasonable balance across its goals of preserving the integrity of price signals in the competitive market, increased transparency for investors, consumers, and policymakers, and avoiding the double payment and over procurement problems that otherwise result from expanded MOPR. While it is inferior in key ways to the FRR-RS, PJM’s clean (not extended) RCO also provides a workable accommodation of these disparate goals.

This section first rebuts the misplaced objections to adoption of any FRR alternative. Opponents wrongly argue that the Commission exceeds the scope of its section 206 authority by incorporating any measures into the replacement rate beyond an expanded MOPR. However, once it is properly exercised,79 section 206 provides ample authority for the Commission to fashion a just and reasonable replacement rate. Opponents also erroneously claim that approval of any FRR alternative is the legal and factual equivalent to maintaining the status quo. This, too, is wrong on its face, as shrinking demand in the market is different in kind from bidding that is artificially too low,80 even if the two result in similar price outcomes. Next, opponents turn to hyperbolic prognostications that adoption of an FRR alternative will doom the competitive markets. These absurd scenarios are not grounded in reality, in which states face (under any

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79 As discussed herein, Clean Energy Advocates’ request for rehearing challenges the Commission’s initial section 206 findings as inadequately supported and contradicted by the record evidence. Whether the initial section 206 determination is valid or not, however, is a separate legal issue from the proper scope of the section 206 proceeding once it is duly initiated.

80 Clean Energy Advocates do not agree with the characterization of bids that reflect payments for non-jurisdictional environmental products as “uneconomic” or “artificially low,” but acknowledge that this is characterization adopted by the Commission in its Order.
alternative proposed) real costs to establish and implement the programs that would lead to resource participation in the FRR alternative. States are only likely to abandon the advantages of competitive markets where compelling public health and safety objectives require it. Moreover, while an FRR alternative can be adopted in the near term, longer term work should continue to address the many barriers and market design flaws that impede the penetration of the carbon-free resources in PJM for which demand continues to grow. Other opponents of a workable FRR alternative assert that the FRR alternative allows states to exercise of buyer-side market power, but fail to articulate how the Commission’s buyer-side market power doctrine applies where consumers are not making an offer into a market, but instead opting to purchase less from that market. Finally, concerns that an FRR alternative is incompatible with retail choice are based on unfounded assumptions about how the FRR alternative will work and these concerns can largely be addressed by providing states with adequate time to develop any new policies needed to protect competition at the retail level prior to implementing the MOPR and FRR alternative. In short, opponents present no real obstacle to approval of an FRR alternative.

Second, this section presents the key advantages of the FRR-RS over PJM’s clean RCO (as described above, Extended RCO is not a viable option). Clean Energy and Consumer Advocates’ FRR-RS proposal would require FRR-RS loads to procure reserves equal to the installed reserve margin, whereas PJM would require that such loads procure reserves equal to the reserve margin that actually clears RPM, despite the fact that this higher reserve margin is unnecessary to achieve the reliability target. The FRR-RS proposal also recognizes that the capacity value of resources should be calculated in the same manner, regardless of whether they sell their capacity through RPM or the FRR-RS, whereas PJM proposes without justification to reduce the capacity value of resources offering into FRR-RS. Next, the FRR-RS allows for more
flexibility in how commensurate load is identified for FRR-RS resources so that load and capacity resources can negotiate compensation in advance of the auction, whereas PJM proposes an illogical mechanism to identify commensurate load that will serve as a barrier to use of the FRR-RS. PJM also proposes to restrict resources that have participated in FRR-RS from returning to RPM so long as they continue to receive a subsidy, which is unnecessary in light of the application of the MOPR to such resources. Finally, the FRR-RS proposal calls for a limited transition mechanism to give states time to update their statutes or regulations as needed to make use of the FRR-RS or protect retail competition; PJM’s RCO includes no such transition mechanism and will therefore lead to unjust and unreasonable rates.

A. Opponents are incorrect that adoption of an FRR alternative is beyond the scope of this proceeding.

Section 206 of the Federal Power Act mandates a two-step procedure that requires the Commission to find that the existing rate is unlawful before setting a just and reasonable replacement rate.81 In its Order, the Commission failed at the first step, as it did not articulate a reasoned basis or provide adequate factual support for its finding that PJM capacity market rules are not just and reasonable and unduly discriminatory. Clean Energy Advocates and other parties requested rehearing of the Order on these grounds. However, assuming the Commission’s initial determination stands, opponents to the FRR alternative, such as the Electric Power Supply Association (“EPSA”), are wrong that the Commission can incorporate expanded MOPR in a just and reasonable replacement rate but cannot include an FRR alternative as a component of the replacement rate.82 This miserly construction of the Commission’s remedial authority under section 206 is inconsistent with the statutory aims and text. Section 206 requires that the

82 EPSA Initial Brief at 28.
Commission implement a replacement rate that is just and reasonable. If the Commission is to apply the MOPR to resources compensated by states for their environmental benefits, it must also implement a workable resource-specific FRR to avoid unjust and unreasonable consequences of that intervention, including consumer-funded build out of unnecessary capacity and interference with state policy prerogatives. EPSA’s argument that a resource-specific FRR alternative would be beyond the Commission’s section 206 authority misconstrues the Federal Power Act and would deny the Commission its well-established discretion to fashion remedies for unjust and unreasonable rates.

The Commission’s threshold finding that PJM’s rates are unjust and unreasonable remains deeply flawed. As detailed in Clean Energy Advocates’ request for rehearing, the Commission did not sufficiently define the scope of its threshold finding that PJM’s tariff is unjust and unreasonable. The Commission determined that states’ “out-of-market support” for resources is “meaningful,” and that such “subsidies allow resources to suppress capacity market clearing prices, rendering the rate unjust and unreasonable.” Yet the Commission left the task of defining key terms such as “out-of-market support” or “subsidy” to the current paper hearing. Similarly, the Commission stated that the replacement rate should include an “expanded MOPR, with few or no exceptions,” while in the same breath requesting comment on “[t]he appropriate scope of out-of-market support to be mitigated by the expanded MOPR.” The Commission thus ordered a paper hearing on a replacement rate before it even defined the nature or scope of the section 206 violation. This omission contravenes the “two-step procedure” mandated by section

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83 Request for Rehearing of Clean Energy Advocates, ER18-1314 et al. at 19-22 (July 30, 2018).
84 Order at P 149.
85 Id. at PP 158, 165.
206, which “requires FERC to make an explicit finding that the existing rate is unlawful before setting a new rate.”  

Additional defects in the Commission’s threshold section 206 finding include: its failure to articulate a theory of market harm beyond conclusory statements that “competition” must be protected; its failure to justify its exclusive focus on price suppression to the benefit of supply interests over customers; and its failure to explain its departure from existing precedent.  

In short, the Commission’s finding in its June 29, 2018 Order that PJM’s rates are unjust and unreasonable suffers from serious defects, and cannot support a replacement rate under section 206. However, assuming this flawed threshold finding ultimately stands, section 206 obligates the Commission to impose a just and reasonable replacement rate. In so doing, the Commission must have the scope to evaluate not only specific fixes to the problem identified, but also related adjustments to market rules required in order to make a proposed solution workable. If the replacement rate includes an expanded MOPR, a resource-specific FRR mechanism is then necessary to avoid unjust and unreasonable outcomes such as “double payment and over procurement.”  

Unlike Clean Energy and Consumer Advocates, EPSA endorses the Commission’s flawed finding that PJM’s rates are unjust and unreasonable, but it contends that a resource-specific FRR alternative would exceed the Commission’s remedial authority under section 206. According to EPSA, because the Commission based its threshold section 206 finding on the threat of price suppression, the Commission’s authority to implement a replacement rate is

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87  Request for Rehearing of Clean Energy Advocates at 22-32.
88  Order at P 160.
89  EPSA Initial Brief at 27.
confined to measures that in EPSA’s view directly address price suppression.\textsuperscript{90} EPSA suggests that implementing a resource-specific FRR alternative alongside an expanded MOPR would be akin to the Commission “perform[ing] a nose job when it has diagnosed the ratemaking equivalent of a ruptured spleen.”\textsuperscript{91} EPSA argues that for the Commission to address the negative consequences of an expanded MOPR, it would have to find this “proposed primary remedy unjust, unreasonable or unduly discriminatory in some way that would justify a secondary remedy.”\textsuperscript{92}

EPSA is incorrect. The authority EPSA cites provides no support for its arbitrary distinction between “primary” and “secondary” remedies or its fragmented approach to correcting unjust and unreasonable rates under section 206.\textsuperscript{93} The Commission is not required to proceed piecemeal when exercising its section 206 authority—first imposing a narrowly-drawn replacement rate, then making a second determination under section 206 to address any unjust and unreasonable consequences of the replacement rate. Rather, once the Commission determines that an existing rate is unjust and unreasonable, the Federal Power Act grants it sufficient discretion to fashion an appropriate remedy.\textsuperscript{94} The Commission may exercise this

\textsuperscript{90} Id. at 29.
\textsuperscript{91} Id.
\textsuperscript{92} Id. at 31.
\textsuperscript{93} See id. at 28 n.127. The cases EPSA cites support the undisputed proposition that the Commission must first find that existing rates are unjust and unreasonable before imposing a new rate under section 206. See, e.g., Public Serv. Co. of N.M. v. FERC, 832 F.2d 1201, 1208 (10th Cir. 1987) (“[W]hen FERC seeks to impose a change not proposed by the company, the statute provides that the Commission must first find the existing provision unjust or unreasonable.”) (internal citation omitted); Mississippi Valley Gas Co. v. FERC, 659 F.2d 488, 503 (5th Cir. 1981) (“[T]he Commission was required to find the old [rate] method unlawful before it could impose a new method.”). The Commission found PJM’s existing tariff to be unjust and unreasonable in its June 29, 2018 Order.
\textsuperscript{94} Advanced Energy Mgmt. All. v. FERC, 860 F.3d 656, 664 (D.C. Cir. 2017) (“The Commission has broad discretion to balance competing concerns.”); Exxon Mobil Corp. v. FERC, 571 F.3d 1208, 1216 (D.C. Cir. 2009) (“When FERC is fashioning remedies, we are
discretion to address narrow “discrete issues” as appropriate,95 or it may recognize that such a narrow approach is insufficient to achieve a just and reasonable outcome, as it has in the instant case. Either way, the choice of just how to craft a just and reasonable replacement rate remains with the Commission.96

EPSA argues that an FRR alternative is beyond the scope of the problem diagnosed by the Commission—i.e., price suppression—but section 206’s limits on the Commission’s remedial discretion do not prevent it from addressing foreseeable undesirable consequences of an expanded MOPR. EPSA correctly notes that a remedy under section 206 should be appropriately “confined to the underlying violation” and “proportionate to the problem being addressed.”97 Additionally, the replacement rate must be just and reasonable as a whole.98 An expanded MOPR paired with a workable FRR alternative satisfies these conditions, addressing the Commission’s concerns regarding the effects of state-sponsored resources on PJM’s capacity market while avoiding severe negative consequences of a so-called “clean MOPR.”

95 Colorado Office of Consumer Counsel v. FERC, 490 F.3d 954, 956 (D.C. Cir. 2007). 96 See Maryland Pub. Serv. Comm’n v. FERC, 632 F.3d 1283, 1285 n.1 (D.C. Cir. 2011) (noting that under section 206 “[i]t is the Commission’s job—not the petitioner’s—to find a just and reasonable rate.”). 97 EPSA Initial Brief at 28-29 (quoting United Distrib. Cos. v. FERC, 88 F.3d 1105, 1132 (D.C. Cir. 1996) (“UDC”)). Notably, the court in UDC considered whether the Commission had impermissibly used pipeline contracts subject to regulation under the Natural Gas Act (“NGA”) as a “jurisdictional hook for non-jurisdictional measures that do not relate to” the Commission’s remedial authority under the NGA. UDC at 1132. Unlike UDC, in the instant case there is no question that a Resource-Specific FRRA would be within the Commission’s jurisdiction as part of PJM’s capacity market construct. 98 See Advanced Energy Mgmt. All., 860 F.3d at 664 (“If the total effect of the rate order cannot be said to be unjust and unreasonable,’ we will defer to the Commission’s finding.”) (quoting Fed. Power Comm’n v. Hope Nat. Gas Co., 320 U.S. 591, 602 (1944)) (emphasis added).
Clean Energy and Consumer Advocates maintain that the Commission’s threshold determination under section 206 that PJM’s current rates are unjust and unreasonable is fatally flawed. However, if the Commission proceeds down its chosen path and expands the MOPR to resources compensated by states for their environmental benefits, there is no basis in section 206 for curtailing its broad remedial discretion to prevent it from proactively addressing undesirable consequences of the MOPR. A workable FRR alternative is not an extraneous “nose job,” but rather a necessary complement to the MOPR if the Commission is to craft a just and reasonable remedy for PJM’s capacity market.

B. Opponents are incorrect that an FRR alternative is equivalent to status quo.

A number of generation owners argue that the Commission should not adopt an FRR alternative because, they claim, “it is a more complicated version of the status quo”\(^99\); “would have exactly the same effect on clearing prices” as the status quo\(^100\); and would “result in price outcomes that are identical to eliminating the MOPR rule altogether.”\(^101\) If the status quo is not just and reasonable, they claim, adopting a separate mechanism that produces the same price outcomes cannot be just and reasonable.\(^102\)

Opponents are wrong, as their argument is based on a fundamental miscomprehension of the Federal Power Act’s just and reasonable standard. In competitive markets, the price outcome is not determinative. The same price that is fair in one context, may not be in another; it is whether the mechanism for reaching that price outcome is just and reasonable that matters. At the heart of the matter, there is a real and meaningful difference when prices are low because of

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\(^99\) Comments of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC at 7 (Oct. 2, 2018) (“Vistra Comments”).

\(^100\) EPSA Initial Brief at 21; see also LS Power Initial Brief at 19 (“the FRR Alternative will do nothing to address the artificial price suppression resulting from subsidies”).

\(^101\) NRG Initial Brief at 3.

\(^102\) Vistra Comments at 7.
some undesirable behavior (the alleged “uneconomic” offers by state-supported resources) and when prices are low because the market has shrunk due to changes in demand fundamentals (states make a policy choice to serve load through a mechanism other than the PJM market). As demonstrated by the Commission’s approval of the original FRR as an alternate means to meet reliability requirements outside of the capacity market, an opt-out from the RPM does not result in unjust and unreasonable price suppression.

The Commission recognized that RPM would be relatively smaller (with a commensurate shift in the demand curve and a different clearing price) as a natural consequence of accommodating state policy. Nevertheless, the Commission viewed that consequence as acceptable where the bifurcated approach would remove the potential effect of uneconomic offers in RPM, enhance transparency, and ensure market integrity. All of these goals are met by the FRR alternative. The generation owners’ complaints about a shrinking pie should not stand in the way of Commission approval of a workable FRR alternative.

1. **Lower price is not “price suppression” where it accurately reflects supply and demand fundamentals.**

   The basic premise of the generation owners’ argument is that acknowledging a state choice to meet reliability requirements through any other mechanism than RPM is not just and reasonable. Under this theory, removing load from RPM shifts the demand curve in a manner that results in “price suppression.” The use of the term “price suppression” is pejorative, and reflects a (flawed) judgment that the resultant lower price is somehow not fair or inconsistent with generation owners’ reasonable expectations. As the ISO-NE grid operator helpfully

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103 Order at P 162 (“Though the capacity market side of the bifurcated capacity construct will be relatively smaller . . .”).
explained in a recent filing to the Commission, simply seeing a lower price outcome does not equate to “price suppression.”

Certain stakeholders have objected to the ISO’s price taker proposal on the grounds that it “suppresses prices.” . . . Because of the downward sloping nature of the [ISO-NE] demand curves, considering the resource adequacy contributions of the retained resources will produce lower auction clearing prices than approaches that ignore these contributions. However, a lower price for providing resource adequacy is not equivalent to price suppression. Rather, the lower price accurately reflects the reduced resource adequacy benefit of capacity at the margin (where prices are properly set), after accounting for the resource adequacy contribution of the retained resource.104

Similarly, here, the lower price seen in RPM where some of PJM’s load is met through a mechanism outside of RPM is a correct reflection of the reduced resource adequacy benefit of capacity at the margin cleared through RPM. It would be inaccurate to value marginal capacity within RPM at the same level when, all other things equal, the demand for reliability benefits within RPM is lower.

Implicit in generation owners’ argument against a mechanism enabling reliability requirements to be met outside of RPM is the contention that the Commission must ensure the market affords investors and developers a stable base of demand—it is only against such a

104 ISO New England Inc. Compliance Filing to Establish a Fuel Security Reliability Standard, Short-Term Cost-of-Service Mechanism, and Related Cost Allocation for Out-of-Market Compensation, EL18-182 at 17 (Aug. 31, 2018) (“ISO-NE Compliance Filing”). Ironically, Calpine Corporation cites the EL18-182 testimony of ISO-NE’s economist, Dr. Christopher Geissler, for his explanation that removing both load and the offer of a resource retained under an RMR yields the same clearing price as leaving the RMR resource in the auction as a price taker. Initial Brief of Calpine Corporation at 6 (Oct. 2, 2018) (“Calpine Initial Brief”). But Calpine ignores the more important point in Dr. Geissler’s affidavit, which is that capacity prices are not suppressed when a resource retained for fuel security purposes is offered in as a price taker, and that “entering resources retained for fuel security as price takers in the [auction] prevents the procurement of excess resources and avoids cost-benefit pricing inconsistencies.” See ISO-NE Compliance Filing, Exhibit ISO-2, Testimony of Christopher Geissler at 17, 26.
flawed standard that a shrinking market can be construed as “price suppressive.” The Federal Power Act has never provided such an extravagant guarantee to sellers. Since the inception of RPM, Commission has recognized that it has no coercive authority to force states or LSEs to remain in the PJM market. Indeed, in approving the original RPM and FRR design, the Commission explained that the new capacity market did not override state authorities retained under the Federal Power Act: “RPM does not mandate or require the construction of new generation, or that any participant satisfy its capacity obligation through the use of any particular resource or set of resources.”105 By arguing that the Commission is not legally permitted to allow resource requirements to be met by any other means than RPM, generation owners propose the opposite—that once states participate in RPM, they are obligated to continue to satisfy one hundred percent of their capacity obligations by the particular set of resources selected through RPM. Thus, the very foundation of opposition to the FRR alternative is ahistorical and in conflict with basic division of wholesale and retail authorities under the Federal Power Act.

2. **Under generation owners’ flawed logic, the current FRR tariff would not be just and reasonable.**

Generation owners’ arguments face another key flaw. If approval of a mechanism that permits states to meet reliability requirements outside of RPM is “price suppressive,” the Commission could not have approved the original FRR as part of a just and reasonable rate. In approving the original FRR, the Commission held that “there is not a single just and reasonable method for satisfying capacity obligations” and found it “appropriate to adopt a dual method of satisfying capacity obligations from which states and utilities can choose.”106 But there is no reason to believe that removal of load through the original FRR would have any different effect

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105 *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 50 (June 25, 2007).

on the shifting of the RPM demand curve than removal of the same quantity of load through a resource-specific FRR. In sum, the Commission has already concluded that it is just and reasonable to accommodate alternative methods of satisfying capacity obligations, notwithstanding that those alternate mechanisms will by definition have an impact on outcomes within RPM.

Generation owners provide little explanation of the discrepancy in their argument. Stoddard, affiant on behalf of NRG, suggests that the original FRR differs because it “was expected to have little material impact on market prices.” But the potential revenue impacts of large-scale departure of load were debated heatedly during a FERC technical conference addressing the design of the original FRR. For example, one panelist responded to concerns about the potential impacts of FRR to the integrity of the market:

["The argument here for the business cycle . . . is this feedback loop and the integrity of the market. While the RPM doesn't have any guarantees, people can leave PJM and decide not to participate in the market, whole groups can walk away, whole generators can decide to take their generation somewhere else. No one has any assurance in this supposed feedback loop."

The claim that the Commission or PJM stakeholders were somehow less aware of or concerned about the effects of allowing load to opt out of RPM does not hold water. These are the same concerns that were raised, and ultimately resolved by the Commission in the form of the FRR construct as it exists today.

NRG witness Stoddard also seeks to minimize the relevance of the Commission’s long-standing acceptance of the FRR by asserting that the FRR has “little material impact on market

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107 NRG Initial Brief at 22 (citing Stoddard Affidavit at 8).
108 Ironically, Stoddard himself participated in these discussions. See Transcript of Technical Conference, In the Matter of PJM Interconnection, LLC, ER05-1410-000 (June 8, 2006).
109 Id. at 279.
prices” because the units removed from the auction are “largely economic,” whereas the units removed under a resource-specific FRR are “by definition, uneconomic” and therefore would have a material impact on those prices.  

Stoddard cites no evidence that capacity resources participating in FRR are generally economic and in fact, there is ample evidence in this record that many of the capacity resources included in FRR plans have high costs and would not clear RPM. While the original FRR’s approval does not eliminate the need for discussion about certain design details regarding implementation of a resource-specific version, it does lay to rest the poorly conceived argument that no such mechanism may be adopted at all.

3. **Removing “uneconomic” bids from RPM achieves the Commission’s goals of addressing potential market impacts, ensuring market integrity and increasing transparency.**

Either FRR-RS or the clean version of RCO reasonably satisfies the Commission’s objectives in adopting an FRR alternative. Both constructs would prevent bids deemed “uneconomic” from being offered into the auction, and ensure that clearing prices result from offers that are, in the Commission’s judgement, competitive. While the FRR-RS achieves this separation from the RPM in a much cleaner and clearer manner by removing both the resource and load before running the auction, the RCO method of treating the carved out resources as zero-bids is equally effective. Either way, there is a clear disconnect from the ability of an

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110 NRG Initial Brief at 22 (citing Stoddard Affidavit at 8).
111 See, e.g., EPSA Initial Brief, Affidavit of Paul M. Sotkiewicz, Ph.D. at 10 (“The most current price that has been reported for an FRR entity is by AEP operating company Appalachian Power Company (“APCo”) at $486/MW-day. This is nearly 3.5 times the market price in RTO for the 2021/2022 Base Residual Auction (“BRA”). Going further back in history, the AEP operating companies had filed rates of $300-$400/MW-day when PJM capacity prices were below $50/MW-day.”) (footnotes omitted); Vistra Comments at 10 n.33 (noting a recent informational filing providing a capacity rate of $435.86/MW/Day for Appalachian Power Company as of June 1, 2018).
112 Though, as discussed in section III.G below, several key fixes would be necessary to make RCO truly workable.
actionable state (or federal) policy to impact the offers that comprise the supply curve, and ultimately the clearing price is an accurate reflection of the value of marginal capacity in RPM, given the remaining demand in the market. The Commission can conclude that either construct works with an expanded MOPR to address the effects of what it considers artificially low bidding in the market, and therefore preserves market integrity.

In addition, either FRR-RS or RCO will enhance transparency. Like the original FRR, PJM will readily be able to track and publicly report the quantities of resource in the FRR alternative for comparison to the capacity participating in RPM. Resources bidding into RPM will have advance notice that other resources are opting into the FRR alternative. Investors will have greater transparency around the drivers of the price outcomes in RPM, and greater certainty as to how newly adopted state policies are likely to interact with the market. States, too, will benefit from greater transparency. By taking over responsibility for ensuring the structures are in place to ensure supported resources are compensated for their capacity, states will see the costs of policy choices more clearly. At the same time, that clarification of state responsibility relieves the Commission of concerns that states are undertaking policies without an eye toward ensuring long-term reliability needs are met.

C. Opponents’ projections of market collapse are baseless hyperbole.

Opponents conjure up a parade of horribles that they claim will follow adoption of an FRR alternative: with nothing holding states back, the dams are broken and subsidies pour forth from legislative coffers until the RPM is left behind, a shrunken, residual raisin of its once robust activity. Vistra claims this “flood of resources” that would seek to use an FRR alternative would similarly swamp the energy markets, depressing prices there as well.113 With a smaller market

113 Vistra Comments at 10.
come even more evils—price volatility, more price suppression, higher long-term capacity costs.\textsuperscript{114} EPSA, with dramatic flair, announces the greater transparency of the new construct will grant us all “the opportunity to watch the collapse of the markets on the equivalent of a live-feed.”\textsuperscript{115} These dire pronouncements are little more than hyperbole, and do not provide a valid basis for rejecting the FRR alternative.

 Commonsense undercuts opponents’ wild speculation. States do not have limitless resources. Policies can be very costly, and whether those costs are charged through retail bills or taxes, legislatures face significant political headwinds when those costs mount. For example, Illinois ZEC annual procurement costs—after being subject to a cap—totaled over \$234 million.\textsuperscript{116} Absent sound public health and safety reasons for taking on such significant additional expenses, such as the dire, existential threat of climate change, resistance is likely to be fierce to such programs.

 In truth, it takes an issue of great public importance and salience to overcome the strong inertia for business as usual within governments. States find great advantage to meeting reliability needs through a competitive auction, in terms of cost and ease. Indeed, some states legal and regulatory structures have now crystallized around the expectation of meeting capacity requirements through the PJM market. It is only if the Commission forces states to make the Hobson’s choice between protecting their residents’ health and well-being and participation in RPM that the exodus from PJM will begin. The best way to ensure the vitality of the competitive markets going forward is to acknowledge that demand for carbon free power is and will continue

\textsuperscript{114} Id. at 11-12.
\textsuperscript{115} EPSA Initial Brief at 23.
to grow voraciously, driven by the exigency of climate change. And to work diligently to further break down the barriers to procuring it through PJM’s markets.

D. Adoption of a Resource-Specific FRRA would not require stranded cost payments to generators.

NRG and Calpine argue that a resource-specific FRR alternative would be such a dramatic change to PJM’s capacity market that they would be entitled to payments for “stranded costs” if it were implemented.117 They rely on Order 888, which in addition to mandating open-access transmission authorized the recovery of stranded cost for certain transmission-owning utilities that could “prove that they had a reasonable expectation of continued service to particular customers.”118 These generators suggest that the replacement rate the Commission contemplates for the RPM would be a similar “titanic shift”119 or “sea change”120 as the transition to market-based regulation signified by Order 888, arguing that they are entitled to “to recoup their investment costs that were reasonably made in reliance on PJM’s competitive market structure.”121

This argument misreads relevant precedent and lacks factual support. In Order 888, the Commission found that it was in the public interest to compensate certain transmission owners due to “a causal nexus between the stranded costs and the availability and use of the tariff services required by the Commission.”122 In the context of cost-of-service regulation of monopoly transmission owners, the causal connection between implementing a new regulatory

117 Calpine Initial Brief at 12-14; NRG Initial Brief at 25-26.
119 NRG Initial Brief at 24.
120 Calpine Initial Brief at 13.
121 Id. at 14.
regime of open transmission access and lost revenue due to the abrogation of contracts with previously captive customers was clear. This proceeding is fundamentally different because a generator has no guarantee of a capacity contract in the RPM, but rather only the opportunity to recover its costs through the competitive market structure.\textsuperscript{123} PJM generators cannot show the same causal nexus between a replacement rate and lost revenues because they simply do not have a “reasonable expectation of continued service to a particular customer.”\textsuperscript{124} Moreover, NRG and Calpine fail to acknowledge that the Commission’s preferred replacement rate aims to preserve the fundamental structure of PJM’s capacity auction.\textsuperscript{125} While a FRR alternative would reduce the total amount of capacity procured through the RPM, shrinking the capacity market is not the same thing as destroying it. Generators are not entitled to a windfall whenever the Commission-mandated changes to competitive markets alter their investment outlook.

E. Opponents are wrong that the resource-specific FRR enables the exercise of buyer-side market power.

Some commenters assert that the resource-specific FRR should be rejected because it will provide further opportunity for states to exercise buyer-side market power.\textsuperscript{126} They assert that a state could offer a subsidy to any capacity resource in order to make it eligible for FRR-RS, and then by having that resource and a commensurate amount of load withdrawn from RPM, benefit from lower prices within RPM for the remaining portion of their load.\textsuperscript{127} First and foremost, this hypothetical scenario relies upon an unfounded assumption that states would act to undermine

\textsuperscript{123} PJM Interconnection L.L.C., 126 FERC ¶ 61,275 at P 150 (Mar. 26, 2009) (agreeing with PJM that the “RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers.”).
\textsuperscript{124} Transmission Access Policy Study Grp., 225 F.3d at 711.
\textsuperscript{125} Order at P 158 (“An expanded MOPR, with few or no exceptions, should protect PJM’s capacity market from the price suppressive effects of resources receiving out-of-market support . . . .”).
\textsuperscript{126} See, e.g., Calpine Initial Brief at 5; NRG Initial Brief at 16.
\textsuperscript{127} See, e.g., Calpine Initial Brief at 5-6.
FERC’s authority over wholesale rates rather than in pursuit of their own legitimate public policy goals. Second, this line of argument seeks to transform the Commission’s buyer-side market power doctrine into a tool that prohibits buyers from taking any kind of action that would have the effect of lowering market prices, regardless of the nature or intent of that action.

The Commission has defined buyer-side market power as “the market power exhibited by entities seeking to lower capacity market prices for the capacity they buy.”\(^{128}\) This market power is exercised through offers made into the capacity market by net buyers who stand to benefit from the resulting lower prices.\(^{129}\) The parties advancing this argument offer no examples of the Commission identifying and mitigating buyer-side market power in any context other than capacity offers.

In the scenario offered by these commenters, there is no capacity market offer that serves as the vehicle to exert buyer-side market power. Instead, there is the absence of an offer and an accompanying reduction of demand for supply sold through the auction. Simply put, the consumer is opting to purchase capacity outside of the auction because the auction does not offer the type of capacity product that the consumer wants. The exercise of consumer choice is not an exercise of market power. It may or may not produce an effect on market prices similar to the exercise of market power, but that is irrelevant because the action taken by the state or LSE is not the type of action that this Commission has ever restricted based on a theory of buyer-side market power mitigation. The parties arguing that FRR-RS offers an avenue to exercise buyer-side market power offer no limiting principle on their premise that any consumer action that


\(^{129}\) See, e.g., id. (referring to offering capacity into the organized capacity market at prices below costs to drive down the market price as the crux of the exercise of market power).
lowers capacity market prices constitutes a prohibited effort to suppress prices; under their approach, efforts by LSEs to lower their RPM costs by reducing peak load would be equally suspect.

To expand the doctrine of buyer-side market power mitigation to restrain any action by consumers over how much capacity they purchase from one type of market versus another would represent a dramatic overreach into decisions that properly rest with states. This is especially so in the absence of any evidence of intent, on the part of the states, to suppress capacity market prices. Some parties have suggested that states incentivize the development or retention of capacity resources with the knowledge or presumed knowledge that this will reduce capacity market prices. That state decision-makers may be aware of the RPM price impacts of their policies does not establish that the state is motivated by those market price impacts, and the Commission should decline to extend its buyer-side market power mitigation objectives to state actions that neither affect capacity market offer prices nor demonstrate actual intent to suppress RPM prices through other types of actions.

**F. Opponents are incorrect that the FRR alternative is incompatible with Retail Competition.**

Clean Energy and Consumer Advocates recognize that many states in PJM have chosen to implement retail choice and agree that the Commission should be mindful of how the FRR alternative might affect those state policies. However, we disagree with those commenters that suggest that the FRR alternative unavoidably conflicts with retail competition. As described below, these concerns are based substantially on misunderstanding or premature assumptions.

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130 See, e.g., PJM Comments at 68-69; NRG Initial Brief, Affidavit of Robert Stoddard on behalf of NRG, ¶ 28. If at some hypothetical point in the future, evidence arose that a state program was in fact materially motivated by a desire to suppress capacity market prices, any aggrieved party could file a section 206 complaint to seek relief from the Commission.
about how responsibility for the cost of capacity procured through the FRR alternative would be allocated to load, and overlooks the role states will invariably play in shaping that allocation. Indeed, ensuring fair and robust retail competition is a matter for state policymakers, not the Commission. One key role that the Commission does play in preventing the substantial changes proposed by PJM’s capacity market rules from disrupting retail choice is ensuring that state policymakers have adequate time to understand the new rules and develop policies to mitigate any adverse effects on retail competition in their states prior to full implementation of the MOPR. Our initial comments noted that “several states may need to modify the rules for their default retail supply auctions . . . pursuant to which suppliers compete to deliver a bundle of energy services that may include capacity purchased from PJM.”

Thus, an adequate transition period is necessary to avoid interfering with state retail choice policies.

One of the parties raising concerns about retail choice is NRG, who suggests that the FRR alternative could lead to different customers within the same zone paying different prices for capacity based on whether the LSE that serves them (including competitive retail suppliers) purchases capacity through the FRR alternative or from the RPM. The Retail Energy Supply Association also expresses concern that the ability of retail suppliers to compete with incumbent utilities will be impaired under a bifurcated market construct. We note that PJM’s proposal to have capacity credits associated with RCO resources given pro rata to all load in the state (while possibly presenting other problems for implementation), would ensure that all LSEs in the

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132 NRG Initial Brief at 31-32.
133 Argument of the Retail Energy Supply Association at 6-7 (Oct. 2, 2018) (“RESA Comments”).
134 See infra section III.G.3.
state have their capacity costs affected in equal measure by implementation of the RCO. Under Clean Energy and Consumer Advocates’ FRR-RS proposal, which provides more flexibility in identifying commensurate load, states would retain the authority to allocate the FRR-RS capacity load in a manner that is consistent with the state’s policies, including retail choice.

The Retail Electric Supply Association also asserts that if the load identified as commensurate with an FRR alternative resource is served by a competitive supplier, “[r]emoving this load [from the auction] without customer consent is akin to ‘slamming’ these customers back to the incumbent utility and denying their ability to choose the electric product and supplier that best meets their individual needs.” 135 Neither Clean Energy and Consumer Advocates’ FRR-RS proposal or PJM’s RCO proposal dictates what entity provides retail service to a customer, or requires customers to take service from an incumbent utility. Under our FRR-RS proposal, any LSE has a choice of whether to purchase capacity from RPM or from an FRR-RS eligible capacity resource, though that choice may be subject to state oversight depending on a particular state’s regulatory framework. Under PJM’s RCO proposal, all load in a state with a policy that provides out-of-market revenue to capacity resources would receive some amount of credit back from what that load paid in RPM costs based on the capacity revenues not paid to the RCO capacity resources. What that load, including retail competitive suppliers, does with that credit, is not defined in PJM’s proposal, but there is no reason to assume that retail competitive suppliers who receive such a credit are somehow at a disadvantage to incumbent utilities in the market for retail customers. 136 Even if load is “removed” from RPM, that has no bearing on which retail

135  RESA Comments at 8.
136  Similar to RESA’s concern about retail customers being forced to take service from their incumbent electric distribution company, NRG misleadingly asserts that the FRR alternative would amount to “[c]arving out certain customers and subjecting them to involuntary bilateral
entity serves that customer, only the wholesale capacity costs that retail entity passes through to its existing customers.

The Ohio Public Utility Commission ("PUCO") explains its concerns about implementation of a resource-specific FRR, and "urges the Commission to recognize the administrative difficulty of implementing this option in Ohio, a retail choice state." The PUCO’s concerns are based on its representation that the costs of capacity from FRR-RS (RCO) units would be recovered as a bypassable surcharge on the bills of customers taking service under the default service tariffs offered to non-shopping customers in the state. Because customers could avoid this charge by shopping for a different electric service provider, the PUCO is concerned that the number of customers over which these costs could be recovered would invariably shrink, potentially leading to difficulty recovering those costs unless the state restricted customers’ ability to leave the default service tariff.

The PUCO’s concerns would seem to arise only in circumstances where the state had no say in how commensurate load associated with FRR-RS (RCO) resources was identified. Both our proposal and PJM’s give states the ability to seek allocations to load consistent with state policy, which would allow Ohio to allocate responsibility for the costs of FRR-RS capacity to all LSEs in the state. That said, we acknowledge that state retail choice policies can vary significantly, making a one-size-fits-all solution challenging to identify upfront. Therefore, it is essential that states both have flexibility regarding the identification of commensurate load and adequate time to review and adjust policies as needed.

137 Argument Submitted on Behalf of the Public Utilities Commission of Ohio at 8-9.
In sum, we agree with commenters that the Commission should consider the implications of a bifurcated capacity market for state retail choice and provide states and load with flexibility and a transition period to enable state policymakers to maintain active retail choice markets. But we strongly disagree that states would face insurmountable obstacles to preserving retail competition in light of the Commission’s proposed bifurcated market design.

G. FRR-RS provides a more workable means to accommodate state policy than RCO, which has several critical failings.

PJM’s RCO proposal is generally responsive to the Commission’s request to develop a workable resource-specific FRR. This stands in stark contrast to PJM’s Extended RCO proposal, which would make the FRR alternative so expensive as to be unusable to states. However, in several key areas, we believe that the RCO fails to provide states with the flexibility they need, and unnecessarily increases costs for load participating in the FRR alternative. These areas, along with a comparison to our FRR-RS proposal, are discussed below.

1. FRR-RS ensures load pays its fair share of the necessary reserve margin to meet grid reliability needs.

PJM proposes that loads participating in the RCO be required to “procure[] the same reserve margin as the portion of the market that clears in the auction,” and asserts that achieving this outcome is one of the key advantages of clearing RCO load and capacity through the auction, rather than removing them from the auction as FERC envisioned.\(^\text{138}\)

Clean Energy and Consumer Advocates’ FRR-RS proposal calls for removing the state-supported capacity and associated commensurate load from the auction, and requiring the latter to procure reserves equal to PJM’s installed reserve margin (“IRM”) target.\(^\text{139}\) This is consistent

\(^{138}\) PJM Comments at 57.

\(^{139}\) See Comments of Clean Energy and Consumer Advocates, Attachment A, FRR-RS Proposal at 10; see also Comments of Clean Energy and Consumer Advocates, Attachment C, Affidavit of James F. Wilson, at Section V.A.
with how the existing FRR is handled and is reasonable given that the IRM is the “level of installed reserves needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management.”\textsuperscript{140} In other words, IRM is the target amount of reserve capacity to be procured because it meets the one-in-ten loss of load expectation objective without overshooting that target and procuring a level of capacity reserves that may not be economically efficient.

PJM’s current variable resource requirement (“VRR”) curve results in capacity procurement that exceeds the IRM target by 4.3 percent on average.\textsuperscript{141} The BRA held in 2018 cleared an amount of capacity equal to a 21.5 percent reserve margin, which is 5.7 percent higher than the target reserve margin of 15.8 percent.\textsuperscript{142} This over procurement results from the position and shape of RPM’s downward sloping demand curve, which recognizes that amounts of a capacity above the IRM are worth incrementally less to load.\textsuperscript{143} Critically, the amount of capacity that actually clears RPM does not represent what that is actually needed for resource adequacy in the region, but instead reflects “auction performance benefits, and the associated quantity outcomes, [that] are not applicable to the loads and resources that are being matched.

\textsuperscript{143} Comments of Clean Energy and Consumer Advocates, Attachment C, Affidavit of James F. Wilson, ¶ 27.
under FRR or FRR-RS.” The reserve margin that RPM clears does not somehow become the correct or ideal reserve margin for the system—that remains the IRM.

The existing FRR rules do not require FRR load to procure reserves equal to that which clears the BRA, but only that equal to the IRM. This is both efficient in that it only requires load to procure the amount of capacity reserves needed to meet the reliability target, but also practical, since the actual reserve margin that the BRA clears is not known in advance of the auction, when FRR plans need to be submitted. It also arguably serves as a resource adequacy backstop for the rare occasions when RPM might clear less than the IRM. These FRR rules have been in place for many years without complaint by other market participants regarding the reserve margin required under FRR plans.

Neither PJM’s comments nor the testimony of any of its witnesses justify imposing the BRA-cleared reserve margin on FRR alternative resources. However, several affidavits submitted by other parties contend that this is necessary to ensure that FRR alternative load is not “leaning on” or free-riding on the reliability provided by RPM. This sentiment is misguided because as James Wilson explains, RPM load actually pays less overall for capacity when the BRA clears more than the IRM, so BRA load is not paying additional amounts for capacity that is then “used” by RCO load. Thus, load served through RPM is not being burdened with

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144 Id.; see also id. ¶ 26 (“While the excess capacity provides some additional reliability value to all customers, the FRR and FRR-RS loads have fully satisfied their fair share of the obligations to meet resource adequacy objectives before the auction.”).

145 Id. ¶ 25 (“Under the FRR rules, the resource requirement is fixed, and there is no quantity adjustment or special cost allocation to FRR entities based on RPM results.”).

146 See NRG Initial Brief at 20-22.

147 Wilson Aff., ¶¶ 20-23; see also Comments of Clean Energy and Consumer Advocates, Attachment C, Affidavit of James F. Wilson, ¶ 28 (“[T]o the extent RPM clears a capacity quantity greater than the target amount based on FPR and IRM (as commonly occurs), the clearing price is lower, and total capacity cost (price times quantity) is also lower, due to the sloped demand curve. So while the loads whose capacity obligations are satisfied through RPM
additional costs for a benefit that they must then unjustly share with FRR-RS load. Nor is the
load served by FRR-RS avoiding any costs, since they would possibly have paid less when RPM
clears an excessive amount of capacity.

Notably, the parties most vigorously arguing for FRR alternative load to procure
excessive capacity are market sellers, not load interests that plans to procure capacity through
RPM. Furthermore, as noted above, it would be both impractical and inefficient to require RCO
load to procure capacity reserves equivalent to the BRA-cleared reserve margin. Without this
unnecessary complication, a major justification for PJM’s preference that RCO resources and
load be cleared through the auction, falls away.¹⁴⁸

2. FRR-RS provides non-discriminatory capacity credit for resources

A core principle underlying Clean Energy and Consumer Advocates’ FRR-RS proposal is
that the contributions of all capacity resources, including those offered through resource-specific
FRR alternative should be recognized, and that “[l]oads should not have to pay for more capacity
than necessary to meet resource adequacy needs.”¹⁴⁹ PJM’s proposal would, by contrast,
unjustifiably diminish the capacity that a resource can offer through the FRR alternative, by
specifying that the maximum unforced capacity (“UCAP”) that resource can offer “will be
determined using the lower of the generation resources’ EFORd calculated based on outage data”
from either the prior 12 months or the 5-year average EFORd.¹⁵⁰ As explained in the attached
affidavit of James Wilson, capacity resources offering into RPM have their UCAP determined

¹⁴⁸  Wilson Aff., ¶ 31.
¹⁴⁹  See Comments of Clean Energy and Consumer Advocates, Attachment A, FRR-RS
Proposal at 4.
¹⁵⁰  PJM Comments at 54 (emphasis added).
based on their EFORd (forced outage rate) from the last 12 months.\textsuperscript{151} Thus, PJM proposes to systematically decrease the amount of capacity that resources can offer into the FRR alternative by docking their value if they had a higher EFORd rate over the last five years, regardless of whether their recent performance is better. PJM offers no explanation for treating FRR alternative capacity resources differently than it treats RPM capacity resources. PJM’s only explanation is that this “maximum amount is designed to ensure that such resource’s capabilities are not overstated based on actual historical performance.”\textsuperscript{152} But PJM offers no explanation for why it would not have similar concerns about overstating the capabilities of a resource participating in RPM, especially considering that PJM has elsewhere confirmed that there will be no physical difference in how the system dispatches FRR-RS (RCO) resources compared to RPM-cleared resources.\textsuperscript{153}

3. **PJM’s proposed default allocation of load pro rata is a barrier to using the FRR alternative.**

Clean Energy and Consumer Advocates’ FRR-RS proposal calls for the capacity resource electing FRR-RS to identify to PJM the associated commensurate load, subject to confirmation by that load and oversight by state regulators.\textsuperscript{154} The capacity resource must elect FRR-RS four months prior to the BRA and then a month prior to the auction the LSE or state entity accepting the capacity assignment would confirm the FRR-RS arrangement and identify the commensurate load.\textsuperscript{155} This framework provides maximum flexibility for capacity resources subject to the MOPR to negotiate with LSEs for bilateral arrangements to assign their capacity, and for states

\begin{footnotesize}
\textsuperscript{151} Wilson Aff., ¶ 5.
\textsuperscript{152} PJM Comments at 55.
\textsuperscript{153} Wilson Aff., ¶ 17.
\textsuperscript{154} Comments of Clean Energy and Consumer Advocates, Attachment A, FRR-RS Proposal at 6, ¶¶ 7-8.
\textsuperscript{155} Id. at 5-6, ¶¶ 5-6.
\end{footnotesize}
to decide what allocation makes sense given the structure of the state environmental programs and retail choice policies. It also ensures that prior to the time the auction is conducted, the FRR-RS capacity resource and commensurate load (whether a particular LSE or state entity) have an opportunity to negotiate regarding payment for capacity outside the auction. While such payment would not occur prior to the delivery year, this ex ante arrangement allows both capacity and load representatives to factor the amount of this payment into their decision about whether to participate in the FRR-RS or RPM.

In contrast, “PJM proposes a default rule that, for each Capacity Resource that has elected the RCO option, all LSEs located in the same state as that resource will have their Locational Reliability Charge reduced by a Resource Carve-Out offset.”\textsuperscript{156} PJM then proposes to “allocate the capacity value of the RCO resource as a pro-rata credit across all load in the state on the basis of [the] load’s proportional share of the state’s Daily Unforced Capacity Obligation.”\textsuperscript{157} Under PJM’s proposal, a state or generator that prefers an alternative arrangement would have to seek Commission approval\textsuperscript{158}

PJM’s proposed allocation to load is problematic in several important ways. It seems motivated more by administrative ease than by the desire to make the FRR alternative workable across the wide variety of situations in which it might be used. First, FRR alternative capacity will not always be located in the same state as the load “sponsoring” it.\textsuperscript{159} As an example, it makes little sense to, as a default, credit Indiana LSEs based on the capacity value of in-state

\begin{footnotesize}
\begin{enumerate}
\item[156] PJM Comments at 61 (citing pro forma Tariff, Attachment DD, section 5.14(a)).
\item[157] \textit{Id.} at 58-59.
\item[158] \textit{Id.} at 59, 61.
\item[159] We use the term sponsor here only for readability, in fact that term suggests a much closer relationship between the capacity resource and the state than typically exists, especially in the case of renewable portfolio standards with decentralized procurement.
\end{enumerate}
\end{footnotesize}
wind resources that are eligible for the RCO based on purchases of their RECs by Maryland or Delaware utilities.\footnote{As explained further below, our proposal would allow the Indiana LSE to decide before the auction that it will accept a capacity assignment from an in-state wind resource. This voluntary arrangement avoids the free rider problems that arise with involuntary identification of commensurate load.} Such allocation either implicitly obligates the Indiana utilities to offer some out-of-auction capacity payment to the wind resource, or leaves the wind resource trying to negotiate for payment from Maryland and Delaware utilities that did not receive a capacity offset credit in RPM. Neither of these situations is workable or fair.\footnote{Although we disagree that the status quo raises any concerns about cost-shifting between states, we note that Clean Energy and Consumer Advocates’ FRR-RS proposal avoids any shifting of “subsidy” costs to consumers in other states. Under our proposal, the “commensurate load” is identified when an LSE or state entity acting on the LSE’s behalf accepts a capacity assignment from an FRR-RS capacity resource. Thus, it is entirely voluntary on the part of the LSE or state as to whether those entities wish to purchase capacity from a “subsidized” FRR-RS resource. By contrast, PJM’s proposed default method for identifying commensurate load could lead to LSEs in states other than the state enacting the environmental policy to make capacity payments to a supported resource. Of course, given the lower capacity costs of these “subsidized” resources, the consumers of that LSE might actually benefit from the out-of-state subsidy.}

Even if the RCO resource is located in the same state as the load “sponsoring” it, a default pro rata allocation will not make sense for state renewable portfolio standard programs where each LSE is responsible for procuring RECs to show compliance. In states where RPS compliance is the responsibility of individual utilities, rather than being done in a centralized manner at the state level it may be more efficient to assign all of the capacity associated with a particular renewable energy resource to the utility (LSE) that already purchases RECs from that resource. PJM’s proposed default allocation also might not make sense where the capacity from an FRR-RS eligible resource could not be fully assigned to load in the state that adopted the policy indirectly responsible for the out-of-market revenues received by that resource due to capacity import limits. Such an FRR-RS eligible resource should be free to negotiate to assign
its capacity to a more local LSE. This flexibility also helps to address concerns such as those expressed by the Maryland Public Service Commission that “pinpointing the commensurate amount of load in each state associated with the specific resources providing the environmental attributes three years in advance of actual production is nearly impossible.” Under the FRR-RS proposal, the sale of capacity and environmental attributes need not be bundled, so the FRR-RS capacity resource need not identify three years in advance which load will be purchasing its renewable energy credits, but could instead assign its capacity to any willing LSE (subject to state approval).

As the Institute for Policy Integrity notes in its initial comments, PJM’s proposed default allocation of credits to load could impede the ability of FRR alternative resources to obtain the capacity revenues they would need to make accepting a capacity obligation worthwhile. Distributing the credits associated with capacity revenues not paid to an FRR alternative resource pro rata across all of the load in the state, without any prior commitment by that load to compensate the capacity resource for its capacity, makes it difficult and costly for the capacity resource to obtain payment from multiple load entities. By contrast, Clean Energy and Consumer Advocates’ FRR-RS proposal places capacity compensation arrangements between FRR-RS capacity resources and LSEs front and center, recognizing that if FRR-RS capacity resources are unable to obtain revenues to cover their going-forward costs (which are rarely if

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162 Initial Comments of the Maryland Public Service Commission at 7 (Oct. 2, 2018) (“MD PSC Comments”).
163 Comments of Clean Energy and Consumer Advocates, Attachment A, FRR-RS Proposal at 6, ¶ 8 and at 12.
164 Comments of the Institute for Policy Integrity at New York University School of Law, EL16-49 et al. at 22-23 (Oct. 2, 2018).
ever covered by the existing state policy payments), then the state policy to encourage generation by those resources will be undermined.\textsuperscript{165}

We recognize that PJM’s proposed default allocation may work for states with centralized procurement or states seeking a level playing field for retail choice providers, but PJM’s proposal that states or generators be required to seek FERC approval for any alternative arrangement is an unnecessary hurdle that will create uncertainty for market participants. A more efficient construct might be for the Commission to approve a range of acceptable methods for identifying the commensurate load, including PJM’s proposed default, from which states can choose.

4. FRR-RS provides reasonable limits on movement between the RPM and the FRR alternative

Clean Energy and Consumer Advocates’ FRR-RS proposal would allow for resources that have participated in FRR-RS to return to RPM, subject to the MOPR, at any time.\textsuperscript{166} In contrast, PJM’s RCO proposal would preclude any capacity resource that has elected FRR-RS from returning to RPM if it receives actionable out-of-market revenues.\textsuperscript{167} Under PJM’s proposal, even once that capacity resource is no longer a “Capacity Resource with Actionable Subsidy” it would still be subject to a significant additional barrier to entry in RPM—the requirement that its offer floor price include any costs of any project investments made while the resource was out of RPM.\textsuperscript{168}

\textsuperscript{165} In many cases, states will want to play an active role in facilitating how these capacity assignments are made to ensure compatibility with other state interests and fairness among LSEs. Regardless of the configuration or degree of state involvement, these capacity assignments will be subject to FERC’s jurisdiction.


\textsuperscript{167} PJM Comments at 55-56.

\textsuperscript{168} Id. at 56.
As Clean Energy and Consumer Advocates pointed out in initial comments, there is little practical reason to exclude resources from moving back and forth between FRR-RS (or RCO) and RPM. Because those resources are subject to the MOPR, they would have extremely low odds of obtaining a capacity commitment in RPM and therefore see little reason to attempt to return to RPM. The only circumstances under which such a capacity resource might have an incentive to return to RPM is where it appears there could be a capacity shortage in its zone and RPM prices were likely to spike in the next RPM base residual auction. In that circumstance, if the FRR-RS resource and its commensurate load were to return to RPM, and if the resource were to clear at its Reference Price, that presumably would prevent an even higher price spike. Such an outcome should be preferred over an outcome with a more extreme price spike given the recognized benefits of stability in RPM prices.

In contrast, PJM’s proposal to prohibit capacity resources from offering into RPM, even at the elevated administrative price floor that PJM’s own proposal would impose, creates the chance for more volatility and price spikes in RPM. PJM offers no reason to believe that capacity resources could readily toggle between the RCO and RPM given the application of the MOPR, and therefore, no compelling basis to justify imposing such a restriction.

5. **FRR-RS provides a critical transition mechanism necessary to avoid disjointed price signals.**

Clean Energy and Consumer Advocates’ FRR-RS construct includes a transition mechanism to provide states with time to update legislation or regulations as needed to enable generators that receive out-of-market revenues under the state’s policy to utilize FRR-RS or to enable the state to ensure proper oversight of decisions by its LSEs regarding participation in the

170 Id. at Attachment C, Affidavit of James F. Wilson, ¶¶ 30-33.
FRR-RS. This mechanism would allow states to request a one-year waiver of the application of the MOPR to capacity resources if the state does not yet have in place the regulatory framework for the FRR-RS, and must document its ongoing process to adopt or clarify relevant state law provisions.

The need for time for states to update their laws was reinforced by the comments of several state entities. The Illinois Commerce Commission details the changes that would need to be made to Illinois law in order for the state to utilize the FRR-RS and states:

Accomplishing and implementing these legislative and regulatory measures in each of the states impacted by the Commission’s June 29 MOPR decision, prior to the PJM’s posting deadline for the 2019 auction parameters is daunting, if not impossible. To the extent that this state-level work is not done in that time frame, the Commission’s vision for the FRR-Alternative or other accommodative measure(s) will not be realized, in which case, the Commission cannot permit the Expanded MOPR to be imposed in those instances. Commission failure to recognize these state-level challenges, and to undertake a reasoned approach to MOPR implementation which accounts for the time needed to resolve these issues, could result in severe shocks that could undermine state and investor confidence in PJM and PJM’s oversight of the grid.

After explaining how the FRR-RS might interact with the District of Columbia’s current renewable energy policies, the D.C. Public Service Commission stated that “it would require the District 9 to 12 months to undertake the necessary statutory and rule changes to begin to implement the new rules.” The Maryland Public Service Commission notes that its legislature would have only 15 business days after a final order in this matter and before its session adjourns to address the significant changes that might be needed to respond to that order, and that “[i]t is

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171 Comments of Clean Energy and Consumer Advocates, Attachment A, FRR-RS Proposal at section V.
172 Id.
174 Arguments of the Public Service Commission of the District of Columbia at 9.
also highly unlikely that any associated regulations could be promulgated in advance of any schedule requirements associated with the upcoming BRA that may be included in PJM’s tariff filing.\textsuperscript{175}

The New Jersey Board of Public Utilities articulated the need for a transition period as follows:

\begin{quote}
The Commission must guard against the unnecessary price spikes that may result from a MOPR without accommodation during the critical transition period. Certain protestors in this proceeding are likely to advocate strongly for a MOPR without accommodation, which could lead to the MOPR being triggered in a transition period without a meaningful opportunity for a State to avail itself of the FRRa paradigm, or a similar accommodative approach . . . In this scenario, customers would be subject to substantially inflated prices caused by the MOPR during the transition period, notwithstanding the intent of the State to choose the FRRa once that paradigm is fully implemented and relevant state regulatory processes conclude. Similarly, a ‘one-year’ MOPR application sends improper price signals to market participants that new generation is needed in an area where it may not be needed. Both the resulting rates and inefficient price signals would lead to an unjust and unreasonable result. Thus, any outcome that would trigger the MOPR solely in the transition period, in addition to any MOPR application without a commensurate accommodation mechanism, would fail to be just and reasonable.\textsuperscript{176}
\end{quote}

PJM’s RCO proposal falls short of accommodating states and preserving meaningful market signals by failing to include a transition mechanism. A transition mechanism such as we proposed in our initial comments, which would allow states to request a one-year waiver of the application of the MOPR to resources supported by the state in order to provide time for changes needed under state law, is a reasonable solution to prevent volatile and meaningless market signals, as well as harm to consumers, while the full new rate design goes into effect.

\textsuperscript{175} MD PSC Comments at 8 n.17.
\textsuperscript{176} Initial Argument of the New Jersey Board of Public Utilities at 9-10.
The wide scope of concerns raised by parties, including states, about the administrative complexity of implementing as-yet unknown resource-specific FRR rules demonstrates that any replacement rate without a transition period of at least a year would be unjust and unreasonable. However, some commenters have argued that no transition period can be allowed because the Commission has already found the current rules to be unjust and unreasonable. This boils down to a position that the Commission should replace one unjust and unreasonable rate with another one. But under section 206, which guides the Commission’s action here, the Commission cannot approve a replacement rate that is itself not just and reasonable. A rate that phases in different components to provide market participants and states time to adjust and develop systems to utilize the resource-specific FRR is consistent with this Commission’s practice and the most prudent course here.

IV. The Commission must reject invitations to expand the scope of the proceeding to new matters.

A. The energy and ancillary services market rules are not at issue in this proceeding.

The purpose of the current paper hearing is clear: to determine a just and reasonable replacement rate for PJM’s tariff that addresses the effects of state policies on the RPM while accommodating states’ right to pursue valid policy goals. Nonetheless, several commenters ask the Commission to expand the scope of this proceeding to encompass not just PJM’s capacity market, but its energy and ancillary services markets as well. In particular,

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177 Order at PP 157-159.
178 Comments of the FirstEnergy Utility Companies, EL16-49 et al. at 2-3 (Oct. 2, 2018) (urging the Commission to “reform the PJM energy, capacity, and ancillary services markets to be efficient, functioning and truly competitive markets that provide reliable and resilient service for all consumers”); Comments to Protect Electric Consumers from Paying Subsidies in PJM Markets by the Office of the Ohio Consumers’ Counsel, EL16-49 et al. at 4 (Oct. 2, 2018) (“FERC should not limit its regulation under the Resource-Specific FRR Alternative to capacity..."
FirstEnergy Utility Companies suggest that an overhaul of all PJM markets is necessary prevent further retirements of what it terms “fuel-secure baseload generators,” criticizing the Commission for not taking “swift and comprehensive action” to address this issue.\textsuperscript{179}

FirstEnergy Utility Companies thus ask the Commission to expand the scope of the current section 206 proceeding to “holistically reform the PJM energy, capacity, and ancillary services markets.”\textsuperscript{180}

The Commission should reject any attempts to broaden the scope of this proceeding beyond its clearly defined purpose. This proceeding is based on a finding under section 206 that PJM’s rates are unjust and unreasonable because of the effect of state policies on capacity market prices; that finding in turn is based on the record created from in PJM’s section 205 filing and Calpine’s section 206 complaint, both of which pertain to state policies’ effects on the RPM.\textsuperscript{181}

While Clean Energy and Consumer Advocates maintain that the Commission’s threshold section 206 finding was incorrect, the combined record underlying the present proceeding provides no evidentiary basis for the Commission to conclude that rates in PJM’s energy and ancillary services markets are unjust and unreasonable.

Additionally, the Commission already considered and rejected the argument that the retirement of so-called fuel-secure baseload generators presents a crisis requiring immediate action.\textsuperscript{182} FirstEnergy Utility Companies echo the Department of Energy’s Notice of Proposed Rulemaking last year, in which the Department argued that “significant retirements of baseload

\textsuperscript{179} Comments of the FirstEnergy Utility Companies at 6, 8.
\textsuperscript{180} Id. at 23.
\textsuperscript{181} Order at P 156.
generation, particularly coal and nuclear resources” threatened grid “resilience,” calling for the Commission to mandate rapid revisions to RTO/ISO tariffs to provide revenue to these resources to prevent further retirements.\textsuperscript{183} The Commission declined to act on the Department’s request, finding the record in that docket did not support a finding that RTO/ISO tariffs were unjust and unreasonable due to “a threat to grid resilience.”\textsuperscript{184} Instead, the Commission began a new proceeding “on resilience more generally and on the need for further examination by the Commission and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets.”\textsuperscript{185} Accordingly, there is a proceeding underway to address the very issues FirstEnergy Utility Companies complain of, and their frustration with the pace of Commission action is not a basis for a new section 206 finding upturning PJM’s energy and ancillary services markets.

**B. Any CASPR-like construct should be rejected.**

Vistra Energy Corp. (“Vistra”) asks the Commission to implement a modified version of ISO-NE’s CASPR construct in PJM. Instead of the replacement rate the Commission outlined in its June 29, 2018 Order, Vistra proposes a two-stage auction process modeled on CASPR that would replace PJM’s current BRA.\textsuperscript{186} All resources seeking a “Material Subsidy” would be subject to an expanded MOPR in the “Primary Auction,” which would function similarly to the current BRA. The second stage, dubbed the “Substitution Auction,” would be a voluntary market in which “subsidized” resources could pay resources that cleared the “Primary Auction” for their capacity supply obligations, with the latter resources agreeing to exit PJM markets permanently. Noting that the Commission found CASPR to be just and reasonable in the ISO-NE context,

\textsuperscript{183} Id. at PP 2-3.
\textsuperscript{184} Id. at P 15.
\textsuperscript{185} Id. at P 17.
\textsuperscript{186} Vistra Comments at 13.
Vistra argues that its proposal appropriately balances the goals of accommodating state policies while ensuring resource adequacy in PJM.

The Commission should reject this misguided proposal. While the Commission approved a similar construct for ISO-NE, the underlying circumstances for PJM are different in several material ways that cast doubt upon whether a CASPR-type construct would be appropriate for PJM. Procedurally, there has been no stakeholder process in PJM to address potential issues with this construct or seek buy-in from key constituencies. State-supported resources should not have to buy their way into the capacity market; accommodating state policy requires that they be able to participate or sell directly the customers through the FRR or into the BRA central auction. Finally, the CASPR substitution auction remains an untested and highly contested mechanism for enabling entry of state-supported resources, which counsels against its hasty export to an entirely different region.

The Commission could have, but did not, propose a CASPR-type construct as part of the replacement rate it detailed in the June 29, 2018 Order. While the Commission left the door slightly open for parties to bring forward other proposals, the vast majority of parties have instead focused on the Commission’s proposed bifurcated capacity market replacement rate. As a result, there has been little to no discussion among stakeholders regarding how a CASPR-type construct might work in PJM. Vistra’s proposal has therefore not benefited from the months of stakeholder engagement that preceded ISO-NE’s proposal of CASPR. Ultimately, 58 percent of stakeholders voted in favor of the CASPR proposal in a sector-weighted vote, and several

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187 Order at P 172 (“As noted, the Commission is initiating a paper hearing to address the just and reasonable replacement rate for PJM’s existing MOPR, including the proposal identified above or any other proposal that may be presented.”).
New England states supported the proposal. There is nowhere near this level of support in PJM, where stakeholders have barely contemplated a CASPR-type construct.

Vistra’s proposal lacks the level of detail, analysis, and input from PJM and its stakeholders needed for the Commission to consider implementing a CASPR-like construct in PJM. Although Clean Energy Advocates opposed ISO-NE’s CASPR proposal, the level of deliberation that ISO-NE undertook for its CASPR filing to the Commission is instructive. ISO-NE produced numerous analyses of New England’s energy markets in whitepapers and presentations, and solicited input from interested parties over the course of a seven-month stakeholder consultation process before finalizing the CASPR proposal.189 ISO-NE’s CASPR filing totaled over 1,000 pages, including specific revisions to tariff language as well as detailed analysis of CASPR and several alternative proposals rooted in econometric modeling of New England’s capacity market.190 Clean Energy and Consumer Advocates believe it would be premature to consider imposing a CASPR-like construct on PJM without a similar level of deliberation.

Beyond this threshold procedural infirmity, a substitution auction akin to CASPR’s is ill-suited to the PJM context. As the Commission recognized, CASPR was “tailored to the specific challenges posed by the state policies in a given region.”191 The chief challenge ISO-NE and the Commission identified for New England’s capacity market was significant growth in new

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renewable resources receiving state support.\textsuperscript{192} Previously, ISO-NE’s MOPR had applied to all new resources, with an exemption for up to 200 MW of renewable resources in each auction (the Renewable Technology Resource, or “RTR” exemption).\textsuperscript{193} ISO-NE and several other parties including the Massachusetts Department of Public Utilities were concerned that the RTR exemption would be inadequate to accommodate all of the new renewable energy development that states were pursuing.\textsuperscript{194} ISO-NE explained its view that “these resources will likely exceed or not qualify for the RTR exemption, resulting in a potentially significant overbuild of the system.”\textsuperscript{195}

ISO-NE thus created CASPR’s substitution auction to “accommodate the entry” of new state-supported resources into ISO-NE’s capacity market over time.\textsuperscript{196} The context from which CASPR emerged in New England is therefore quite distinct from that of PJM, which has until now fully accommodated state policies by allowing new and existing resources receiving out-of-market revenues as a result of state programs to participate freely in RPM. Thus, the baseline conditions in the two regions are very different in ways relevant to the types of replacement constructs that may be effective and acceptable to key constituencies.

\textsuperscript{192} \textit{Id.} at P 4.
\textsuperscript{193} \textit{Id.} at P 3.
\textsuperscript{194} \textit{Id.} at P 6 (“As a result of the New England states’ increase in out-of-market procurements, ISO-NE states that it, along with the states and the New England Power Pool Participants Committee (NEPOOL), sought a ‘better way to integrate these state policies into the competitive wholesale markets.’”) (quoting CASPR Filing at 4); CASPR Order at P 13 (“Massachusetts DPU argues that CASPR provides just and reasonable market adjustments without which Massachusetts ratepayers will be harmed by being forced to pay twice for the capacity associated with Sponsored Policy Resources and because the region will otherwise inefficiently develop more generation than it requires.”).
\textsuperscript{195} CASPR Order at P 4.
\textsuperscript{196} \textit{Id.} at P 45.
CASPR was designed as a solution to accommodate entry of new resources, whereas Vistra proposes that this untested substitution auction mechanism would also somehow facilitate the retention of existing resources that will become subject to the MOPR. Vistra’s witness, Christopher J. Russo, acknowledges this key difference but does not explain its implications.197 A new resource may find it economically worthwhile to attempt to buy out the capacity obligation of an existing resource, given that it could provide decades of capacity revenues. An existing state-sponsored resource may see much less potential future revenue due to its shorter remaining plant life, and therefore not be able to bid sufficiently high into the substitution auction, especially compared to new entry also offering into that auction. Clean Energy and Consumer Advocates contend that a substitution auction aimed at accommodating the entry of new resources is ill-equipped to address issues arising from state sponsorship of both new and existing resources.

Vistra attempts to piggy-back on the Commission’s approval of CASPR, noting throughout that its proposal mimics aspects of CASPR that the Commission found just and reasonable earlier this year. Yet the Commission’s finding that certain components of CASPR were just and reasonable in the ISO-NE context says little about whether those measures would be just and reasonable for PJM. As explained in the attached affidavit of James Wilson, there are many differences in the PJM and ISO-NE markets that would need to be considered in deciding whether a CASPR-type construct is appropriate for PJM and how it should be adapted. These include the different zonal structure, retirement rules and how they interact with the capacity market, pace of new entry, and capacity demand curve location.198 PJM’s service

197 Vistra Comments, Affidavit of Christopher J. Russo at 16.
198 Wilson Aff., ¶ 80.
territory is much larger than ISO-NE’s and is home to over four times as many customers. PJM has a different tariff designed to accommodate a different generation mix and transmission system, not to mention the regulatory authority of thirteen states and the District of Columbia. Most pertinently, the state policies at issue in the present paper hearing are distinct from those addressed in the CASPR Order. Vistra has also proposed a number of modifications to CASPR that may make it less likely that the substitution auction will function; at the same time, it has retained other elements that may not be appropriate for PJM given the differences in the two regions.199

The differences between PJM and ISO-NE are simply too great to impose a CASPR-like construct without far greater deliberation on how to adapt the construct to PJM’s unique context. One key difference is that the increase in the clearing price in the first stage of a CASPR-type construct in PJM would likely be far more significant than the increase in ISO-NE, because the MOPR in PJM would apply to new and existing resources, whereas in ISO-NE, the MOPR would apply to only new resources. It cannot be assumed that the Commission would view the clearing price resulting from an auction in which all new and existing state-supported resources in PJM were mitigated as just and reasonable, simply because it found much smaller increases in ISO-NE to be acceptable.

A final example is limitations on inter-zonal transfer of capacity supply obligations. Vistra proposes to address this issue with “the same limitation” on such transfers as those contained in CASPR,200 but it fails to address serious potential pitfalls of limiting inter-zonal transfers in this way in the PJM context, such as concentration of market power within zones and

199 Wilson Aff., ¶ 83.
200 Vistra Comments at 25 n.69.
the “lumpiness” problem that confounds matching of large retiring resources with smaller-scale substitution resources. In fact, Vistra explicitly punts on the “lumpiness” question in a footnote, leaving it to PJM to design a “market clearing logic” that fixes this thorny issue.

Where Vistra’s proposal does depart from CASPR in an attempt to reflect different circumstances in PJM, these departures are often mistaken. For example, the Commission approved ISO-NE’s proposal to allow the accumulated amount of the RTR exemption to be used while CASPR implementation begins, as a transition mechanism and so as not to disrupt investments already underway. Vistra proposes no similar transition mechanism for PJM, despite the fact that its proposal would be equally disruptive to new investment, on grounds that the “issue of subsidized generation in PJM is different,” and relates primarily to existing resources. While it is true that the alleged conflict between state policies and wholesale markets in PJM relates to existing as well as new generation, that does not mean that new renewable energy resource development in PJM has not relied upon the status quo and would not be unfairly affected by precipitous changes in market design. Indeed, the changes in PJM for new renewable resources would be even more stark than those in New England, where project developers always had to account for the uncertainty regarding available space under the RTR

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202 Vistra Comments at 25 n.70 (“Given that the substitution auction is a clearing mechanism and does not necessarily involve one-to-one matching of resources, PJM may have to develop market clearing logic for the Substitution Auction to implement these requirements.”).

203 CASPR Order at P 99 (“We find ISO-NE’s transition proposal to be a balanced approach for implementing CASPR’s alternative means of accommodating state policies, while attenuating any potential adverse impacts on pending investments that could result from an immediate change to the market rules.”).

204 Vistra Comments, Affidavit of Christopher J. Russo at 17.
exemption; in contrast, new renewable energy resource developers in PJM could rely upon being able to offer into PJM without mitigation.

New England states, Clean Energy Advocates, and others identified serious flaws in ISO-NE’s CASPR proposal, and several requests for rehearing of the CASPR Order are pending before the Commission.\textsuperscript{205} For example, the CASPR Order contains no finding that CASPR will in fact facilitate the entry of new state-sponsored resources in New England.\textsuperscript{206} If the Commission could not determine that CASPR would function as intended in ISO-NE despite the extensive record developed in the CASPR proceeding, it would be unreasonable for it to conclude that that a CASPR-like construct would be just and reasonable in PJM’s market based on Vistra’s submittal. Quite simply, the substitution auction mechanism that is the heart of CASPR is \textit{untested}. The Commission should not expand that untested model to an entirely different and much larger RTO, without at least allowing for robust stakeholder engagement to identify potential hurdles to a successful substitution auction. The stakes for market participants and consumers are simply too high to experiment with RPM in this manner. A CASPR-type construct such as Vistra proposes fails to consider, let alone justify, the increases in costs for consumers that would result, whether from exit payments to retiring generators in the substitution auction if the construct works as intended, or from consumer-funded build out of excess capacity if it does not.\textsuperscript{207}

In short, Vistra’s proposal does not meet the Commission’s minimum requirements of a replacement rate. A substitution auction is an especially poor fit to address the issues the

\begin{footnotesize}
\begin{itemize}
\item[205] Order Granting Rehearings for Further Consideration, ER18-619 (May 7, 2018).
\item[206] Request for Rehearing of the Clean Energy Advocates, ER18-619 at 17 (Apr. 9, 2018).
\item[207] See Connecticut Protest at 41 (detailing ways CASPR would increase customers’ capacity costs).
\end{itemize}
\end{footnotesize}
Commission identified with PJM’s capacity market. Clean Energy Advocates maintain their that view CASPR is not just and reasonable for ISO-NE, and further maintain that it would be reckless for the Commission to consider imposing a CASPR-like construct in PJM without due consideration of the complexities of adapting the construct to PJM’s unique context.

C. Further stakeholder process to explore the Maryland PSC and carbon pricing proposals is warranted.

Of the additional proposals made in the initial comment period, the competitive “carve-out” auction outlined in the Maryland Public Service Commission’s (“PSC”) comments, as supported by the Organization of PJM States, Inc. (“OPSI”), and the comments suggesting a PJM carbon price appear facially promising, but they require further assessment in the form of stakeholder process. In the Maryland PSC’s competitive “carve-out” auction, load associated with state climate policies would be carved out of the existing capacity market and placed into its own auction to meet the capacity needs associated with the carved-out load. 208 Although OPSI’s formal comments to FERC focused on the MOPR and accommodation of state policies, the organization declared its support for this competitive carveout plan in a public letter to PJM on September 26. 209

Eastern Generation and Exelon both suggest further consideration of implementing a carbon price in PJM, potentially under a section 205 filing. Eastern Generation points to the analysis done by Brattle Group for NYISO as an example of how a PJM-wide carbon price could work: PJM would assess suppliers a set charge per ton of carbon dioxide emissions through the standard settlement process, which would then be incorporated into the unit commitment

208 MD PSC Comments at 10-11.
dispatch and clearing price determination. In addition, Exelon’s comments note that many stakeholders recognized carbon pricing as the most efficient way to incorporate environmental externalities in a 2017 proceeding on state policies and wholesale markets (Docket No. AD17-11-000). The Nuclear Energy Institute further adds that carbon pricing would be more effective than an expanded MOPR.

While neither the competitive carve-out auction nor the RTO-wide carbon price have been fleshed out enough to provide the basis for FERC approval, both offer promising areas for further investigation and stakeholder input, all of which will take time. The ongoing carbon adder proceedings in NYISO are a good example of the time required to do due diligence in such stakeholder feedback processes.

CONCLUSION

For the foregoing reasons, Clean Energy and Consumer Advocates respectfully request that any approval of an expended MOPR be paired with the FRR-RS or, at minimum, a workable FRR alternative, that will fully accommodate state policy. Clean Energy and Consumer Advocates further request that the Commission reject PJM’s Extended RCO proposal as not just and reasonable or unduly discriminatory.

CONTINUED FOR SIGNATURE

210 Initial Brief of Exelon Corporation at 7.
211 Comments of the Nuclear Energy Institute at 2-3.
Respectfully submitted,

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CERTIFICATE OF SERVICE

Pursuant to Rule 2010 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.2010, I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic means.


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Exhibit A

Reply Affidavit of James F. Wilson
in Support of the
Reply Comments of Clean Energy and Consumer
Advocates
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.                     )

REPLY AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE REPLY COMMENTS OF
CLEAN ENERGY AND CONSUMER ADVOCATES

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I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. My experience and qualifications were described in my affidavit in support of the comments of the FRR-RS Supporters filed October 2, 2018 in this proceeding (“Initial Affidavit”), and in my CV attached thereto.

3. In an order dated June 29, 2018,1 the Federal Energy Regulatory Commission (“Commission”) instituted this proceeding and called for a paper hearing. Initial comments were filed October 2, 2018. This reply affidavit was prepared at the request of Natural Resources Defense Council, Sierra Club, Sustainable FERC Project, and the Office of the People’s Counsel for the District of Columbia. In addition to my Initial Affidavit noted above, I also prepared an affidavit and reply affidavit in the earlier proceeding following the PJM Interconnection, L.L.C. (“PJM”) MOPR and repricing filing in Docket No. ER18-1314.2

4. My assignment in this reply round was to review PJM’s initial submission (“PJM Submission”), and the comments of other parties, and to respond as necessary regarding 1) the resource-specific Fixed Resource Requirement (“FRR”) alternative called for in the June 29 Order at P 160 (hereafter, “FRR-RS”, including PJM’s variant, “RCO”) and 2) proposals for capacity

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“repricing”, including PJM’s new proposal that it calls “Extended RCO,” and other variants. In particular, I respond to the PJM Submission and the supporting affidavits of Adam J. Keech (“Keech Affidavit”) and Hung-po Chao, Ph.D. (“Chao Affidavit”), and also to the affidavits of Robert B. Stoddard on behalf of NRG Power Marketing LLC (“Stoddard Affidavit”), Paul M. Sotkiewicz, Ph.D. on behalf of the Electric Power Supply Association (“Sotkiewicz Affidavit”), and Christopher J. Russo on behalf of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC (“Russo Affidavit”).

II. Summary and Recommendations

1. The June 29 Order called for an expanded MOPR and a resource-specific FRR alternative, while rejecting PJM’s proposal for capacity “repricing.” The Commission should now follow through with this approach, and direct PJM to implement non-discriminatory FRR-RS provisions without PJM’s harmful and unnecessary repricing proposal, or any other repricing proposal.

2. With regard to FRR-RS, the quantity of load and resources should be matched based on the PJM Installed Reserve Margin (specifically, the Forecast Pool Requirement “FPR”, as is required for FRR), and locational constraints should apply. States should be able to elect to have FRR-RS resources and commensurate loads removed from the RPM Base Residual Auctions, per the June 29 Order, or, if the Commission finds it acceptable, cleared in the auctions, as PJM has proposed.

3. With regard to PJM’s new capacity repricing proposal, this should be rejected for the same reasons the Commission rejected the previous one. Nor should any other form of repricing proposed by other commenters, including variants of New England’s CASPR regime, be approved. RPM prices will find the correct level that balances entry and exit and accurately signals
the need for resources without such repricing provisions, and will not find that level, and will confuse investors, if repricing is applied.

A. Recommendations re: FRR-RS (RCO) Details

4. PJM’s RCO proposal is in many respects consistent with the FRR-RS design principles and objectives I identified in my Initial Affidavit (pp. 8-10), and with the FRR-RS proposal put forward by FRR-RS Supporters. However, PJM and various commenters propose a number of provisions that should be rejected, some of which I will discuss in further detail later in this reply affidavit:

5. **Unforced Capacity of RCO Resources:** PJM proposes (p. 54) to base the Unforced Capacity value of RCO resources on the lower of a resource’s EFORd for the past 12 or 60 months. PJM provides no rationale for this discriminatory proposal, which violates the Reliability Assurance Agreement ⁶ and should be rejected. The RAA (Article 1: Definitions) requires that Unforced Capacity be determined on a non-discriminatory basis, and using the recent 12-month period:

   “Unforced Capacity: “Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.”

6. **Amount of Commensurate Load:** PJM’s proposal, contrary to the current FRR rules and PJM resource adequacy requirements, would impose the actual RPM-cleared reserve margins on the commensurate loads associated with FRR-RS resources. The case for this proposal is flawed and it should be rejected; the commensurate load quantity associated with FRR-RS

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³ Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region (“RAA”).
resources should be determined in the same manner as the commensurate load associated with FRR resources (in both cases, based on the PJM region installed reserve margin and resource adequacy requirements as described in the RAA).

7. **FRR-RS Resources and the Base Residual Auction**: PJM proposes to leave RCO resources and the associated commensurate loads in the RPM auctions; this approach has some advantages but also drawbacks. The Commission should allow states to have their FRR-RS resources and commensurate loads removed from the auctions, as contemplated in the June 29 Order. If the Commission finds PJM’s in-auction approach acceptable, it should be an additional option available to states.

8. **Identification of Commensurate Load/LDAs**: The FRR rules currently allow, but place limits upon, the amount of FRR resources located outside of an FRR entity’s Locational Deliverability Area (“LDA”) that may be included in the entity’s FRR Plan. These restrictions ensure that an FRR entity uses no more than its “fair share” of an LDA’s transmission capacity. This same concept should be applied to FRR-RS resources and commensurate loads, while allowing states the option to use the transmission capacity allocation for FRR-RS resources.

**B. Recommendations re: Capacity Repricing (Extended RCO) and Variants**

9. Capacity Repricing (such as PJM’s “Extended RCO”) is not needed and would worsen, not improve, the price signals that would result from RPM with FRR-RS. PJM’s new variant of its Capacity Repricing proposal,\(^4\) Extended RCO, has new features and new flaws, and would actually worsen the “disconnect” that the Commission objected to in its June 29 Order (at

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P 64). It would also introduce new opportunities for market participants with no intention to provide capacity to nevertheless be compensated as if doing so. PJM’s Extended RCO, and various other proposals for repricing, would lead to price signals that misrepresent the need for capacity, confuse investors, and result in chronic excess capacity.

10. The remainder of this reply affidavit is organized as follows. Section III addresses certain FRR-RS (RCO) provisions. Section IV explains why repricing is not needed, and evaluates PJM’s repricing proposal and other such proposals.

III. The Resource-Specific FRR Alternative (FRR-RS; “Resource Carve Out”)

A. PJM’s Resource Carve Out (“RCO”) Proposal

11. As noted above, the June 29 Order called for a resource-specific FRR alternative. PJM’s proposal, called Resource Carve-Out\(^5\) (“RCO”), has the following elements:

1. The RCO option is available to Capacity Performance resources that are subject to the MOPR due to an Actionable Subsidy (p. 52);

2. Resources electing the RCO option receive no RPM capacity payment (p. 53), but obtain a capacity commitment and are expected to perform as Capacity Performance resources in the PJM markets, with all the rights and obligations that

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\(^5\) I note that “Carve Out” is an inappropriate and misleading term for FRR-RS. FRR-RS affords resources to which the MOPR will apply an opportunity to be treated as other capacity resources and have their capacity recognized. As used by the Commission, “carve out” typically suggests some form of special and advantageous treatment, which is not proposed here. See, for instance, *Southwest Power Pool, Inc.*, 160 FERC ¶ 61,115 (2017), page 1 footnote 2 (“for the purposes of this order, an agreement that has “carved-out treatment” refers to a grandfathered agreement (GFA) to which congestion and marginal loss charges will not be assessed for the transmission of energy”). PJM attempts to justify use of the misleading and pejorative “carve-out” label on the basis of potential “confusion” with the existing FRR, claiming (incorrectly) that FRR-RS/RCO is very different from FRR (PJM Submission, p. 8 footnote 15).
entails (must-offer requirement, Capacity Performance non-performance penalties, right to procure replacement capacity, etc.; p. 57, p. 63);

3. RCO resources would be included in base residual auctions and deemed offered at zero dollars; RCO capacity and commensurate load would not be removed from the auctions;

4. The commensurate load associated with RCO resources would reflect the cleared reserve margins from the base residual auction;

5. As a default rule, all Load-Serving Entities located in the same state as a RCO resource (which may not be the state that sponsored the resource) would have their Locational Reliability Charges reduced proportional to their Unforced Capacity Obligations, based on the UCAP of the RCO resource (pp. 61-62). However, the state sponsoring a RCO resource could propose an alternative approach for allocating the capacity credit to loads (p. 59);

6. Other details of PJM’s RCO proposal:
   
   i. Only annual resources (including commercial aggregates of seasonal resources) can elect RCO (p. 53);
   
   ii. An entire resource elects RCO, partial election is not allowed (p. 55);
   
   iii. The deadline to elect RCO is 45 days before the base residual auction;
   
   iv. RCO election closer to the delivery year is not accommodated, and RCO resources are excluded from the RPM Incremental Auctions (p. 56), but are permitted to procure replacement capacity (pp. 63-64);
   
   v. A RCO resource can return to RPM only if it no longer has an Actionable Subsidy (p. 55).
12. Note that there is broad agreement that FRR-RS (RCO) resources shall be Capacity Performance resources with all the obligations that involves, and in the Delivery Year will be controlled by PJM no differently than resources cleared through PJM.\(^6\) Similar to FRR resources or capacity resources that have assigned their capacity on a bilateral basis, FRR-RS resources will be identical in operation to all other Capacity Performance resources, and differ only in how they were contracted and will be compensated. There is no physical relationship between FRR-RS resources and the commensurate loads credited with their contribution to resource adequacy; the relationship has only to do with accounting for resource adequacy responsibility and cost.

13. Note also that FRR-RS, as proposed by the FRR-RS Supporters and also as proposed by PJM (RCO), is quite similar to the existing FRR mechanism defined in the RAA (Schedule 8.1). Under both FRR and FRR-RS (RCO), capacity resources are matched with commensurate loads and are compensated in a manner different from RPM-cleared resources, but otherwise are the same as all other PJM capacity resources (and in particular, have the same Capacity Performance obligations and are operated the same as other resources, as noted above).

14. PJM and other commenters attempt to argue that FRR-RS is quite different from FRR, but these arguments fail. Witness Stoddard asserts without evidence that FRR resources are “economic” while FRR-RS resources are “uneconomic,” and suggests that this is a significant difference. However, most FRR resources were located in the AEP zone, where many resources have recently or will soon retire, calling into question whether they were economic. And while nearly all commenters acknowledge that states may sponsor resources to recognize values not

\(^6\) See, for instance, PJM Submission Attachment A proposed tariff changes, Attachment DD Section 5.15 A(vi)(D) (“Any Carved Out Resource shall have a capacity commitment as if the resource had cleared in an RPM Auction”).
captured in the PJM markets (such as environmental externalities), Mr. Stoddard and other commenters then proceed to ignore this fact, labeling these resources “uneconomic” and proposing auction rules that could be justified only under that assumption. Witness Sotkiewicz suggests that resources can elect FRR-RS status, and this is a significant difference from FRR, which is initiated by a load-serving entity; however, this ignores the fact that a resource electing FRR-RS will only be compensated if a state arranges for it to be, or if it enters into a bilateral capacity assignment. Finally, NRG Power Marketing LLC argues (Initial Brief, p. 23) that FRR includes net-short/net-long rules, and this “protection” is missing from FRR-RS; but this makes no sense, because the commensurate load for FRR-RS resources is calculated to correspond exactly to the resources’ unforced capacity. Because, as the June 29 Order suggests, FRR-RS is a variant of FRR, the Commission-approved features of the FRR rules are generally applicable to FRR-RS.

15. The following subsections address certain of these provisions as proposed by PJM, and related proposals by other commenters.

B. Quantity of Commensurate Load

16. PJM witness Adam J. Keech argues (Keech Affidavit, p. 3) that contrary to the FRR rules, the commensurate load associated with RCO resources should be required to purchase the same reserve margin as cleared in RPM:

“… this approach guarantees that carved out load, and load within the PJM footprint that has purchased capacity through the Base Residual Auction, are required to purchase capacity to meet the same reserve margin. This is important to maintain consistent reliability and costs across loads that have purchased capacity through the auction and those that have elected to carve out. Further, it ensures that if the Carved Out Resource is unavailable during a capacity emergency, the subsidizing load has purchased reserves to cover the potential unavailability of the Carved Out Resource and will not be “leaning” on the system.”
17. These arguments fail. First, “consistent reliability” is assured for all loads without this provision. As with FRR resources, PJM will dispatch all resources in the same manner to meet all loads, as witness Keech and the PJM Submission acknowledge. While the amount of capacity and reserve margin associated with the two types of loads may differ depending upon auction results, FRR and FRR-RS resources fulfill their share of resource adequacy obligations, and the RPM-cleared capacity may represent a larger or smaller reserve margin.

18. Consistent costs are not maintained across the two types of loads with or without this approach; RCO commensurate loads will certainly pay different prices per MW-day for capacity than will RPM loads. The prices and costs paid by loads met through RPM will depend upon clearing along the sloped capacity demand curve, and costs will actually be lower to the extent RPM clears excess capacity, as it usually does.

19. Nor is this provision appropriate to ensure the commensurate load has purchased reserves to cover the potential unavailability of the resources; as with FRR resources, requiring the commensurate loads to acquire the Forecast Pool Requirement (“FPR”) accomplishes that.

20. The Stoddard Affidavit also argues for imposing the RPM-cleared reserve margin on FRR-RS resources, asserting that otherwise there would be an “inequitable” result that the loads charged through the RPM auction “pay for more of the market-cleared resources” than they would have absent the FRR-RS resources. As with other commenters, Mr. Stoddard misses the fact that it is RPM dollars, not MW, that are allocated to loads. When RPM clears excess capacity, it does

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7 Keech Affidavit, p. 3 (“Whether a resource is subsidized or not has no bearing on how PJM will operate the transmission system or schedule and operate resources in real-time.”); PJM Submission, p. 63 (consistent Capacity Performance obligations will be required of all capacity resources, to maintain grid reliability).

8 This was explained in detail in my Initial Affidavit, p. 12.
so at a much lower price and total cost, so the share of capacity cost borne by RPM-cleared loads actually declines sharply.

21. Table 1 drives this point home. Based on the parameters from the May 2018 base residual auction for the 2021/22 Delivery Year, if RPM clears exactly the Reliability Requirement based on the Forecast Pool Requirement, the RPM cost of capacity is roughly $512/MW-day per MW of peak load. If instead the auction clears 2% excess, the clearing price is about $310/MW-day, and the RPM cost per unit of peak load is much lower, roughly $344/MW-day. If the auction clears roughly 5% excess at about $140/MW-day (the actual result), the RPM cost per unit of peak load falls further, to about $160/MW-day. So while the RPM loads are nominally allocated somewhat more capacity when RPM clears a large excess, the only thing that really matters – the allocated cost – declines sharply, because the drop in price is much greater than the increase in quantity.

Table 1: Impact of Cleared Excess Capacity on Cost to RPM Loads

<table>
<thead>
<tr>
<th>RPM Clearing Result:</th>
<th>Forecast Peak (MW)</th>
<th>Reliability Req't (MW UCAP; peak x FPR)</th>
<th>RPM cleared quantity (GW UCAP)</th>
<th>RPM clearing price ($/MW-day)</th>
<th>RPM cleared installed reserve margin</th>
<th>RPM total cost ($bil./year)</th>
<th>Total cost per unit peak load ($/MW-day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. At FPR (no excess cleared):</td>
<td>140,540</td>
<td>153,161</td>
<td>153,161</td>
<td>$ 470</td>
<td>15.8%</td>
<td>$ 26.3</td>
<td>$ 512</td>
</tr>
<tr>
<td>2. 2% excess:</td>
<td>140,540</td>
<td>153,161</td>
<td>155,800</td>
<td>$ 310</td>
<td>17.8%</td>
<td>$ 17.6</td>
<td>$ 344</td>
</tr>
<tr>
<td>3. ~5% excess:</td>
<td>140,540</td>
<td>153,161</td>
<td>160,300</td>
<td>$ 140</td>
<td>21.2%</td>
<td>$ 8.2</td>
<td>$ 160</td>
</tr>
</tbody>
</table>
22. By contrast, FRR-RS commensurate loads and resources, contracted outside of RPM and possibly on a long-term basis, likely would not “see” the price drop resulting from RPM clearing an excess. Imposing a portion of the larger RPM cleared quantity onto the FRR-RS commensurate loads, as witnesses Keech, Stoddard, and others propose, would result in an even larger price drop per unit of peak for the RPM loads, while increasing the cost for FRR-RS commensurate loads who were not participating in the RPM auction and should be held harmless for its results. Put another way, assuming the capacity cost incurred by FRR-RS loads is largely insulated from RPM price outcomes, as RPM clears a greater excess, RPM loads pay a rapidly shrinking fraction of the overall cost of capacity. Imposing a higher reserve margin on the FRR-RS commensurate loads would only cause the RPM loads’ share of the cost to shrink even faster.

23. The notion that the RPM-cleared reserve margin should be imposed on FRR-RS resources and commensurate loads also has an absurd outcome when capacity is relatively scarce. If RPM clears below the Reliability Requirement, the FRR-RS commensurate load quantity would be increased to reflect the same relationship to the FRR-RS UCAP (now, less than the FPR), worsening the overall capacity circumstance relative to the current rules that require FPR.

24. Other arguments for imposing a higher reserve margin on FRR-RS resources (e.g. NRG Power Marketing Initial Brief, p. 21) incorrectly assume a physical relationship between the resources and commensurate loads, which, as explained above, is incorrect.

25. Proposals to impose expanded reserve margins on FRR-RS commensurate loads should be rejected. The Commission should require that the commensurate loads are calculated in the same manner as for FRR loads, based on the FPR.
C. Treatment of FRR-RS Resources and Commensurate Loads in RPM Auctions

26. Witness Keech argues (p. 3) that RCO resources and commensurate loads should be left in the RPM Base Residual Auctions, contrary to the June 29 Order, which called for them to be removed from the capacity market.9 He claims several benefits for this approach. However, only one of the claimed benefits has any merit, and it is likely only a benefit for some, but not other, states that might take advantage of the RCO/FRR-RS alternative.

27. First, witness Keech claims this approach is “consistent with the physical reality of system operations”, and suggests that approaches that remove the resources and commensurate loads “suggest a physical relationship between the two that is inconsistent with system operations.” However, there is no basis for the assertion of a physical relationship when loads and resources are matched outside of RPM for purposes of accounting for capacity obligations and costs, as the existing FRR rules, and existing bilateral capacity assignments, prove.

28. Second, witness Keech states that this approach results in the commensurate loads acquiring the same reserve margin as loads whose obligations are met through the RPM auctions. As discussed above, this proposal is inappropriate and should be rejected.

29. Witness Keech further claims that keeping the RCO resources and commensurate loads in the auction ensures that when resources are matched to loads in a different LDA, transmission limits are correctly accounted for. However, the RPM rules already successfully address this issue for FRR loads and resources, which are removed from the auctions. The RPM rules call for FRR resources to meet a Minimum Internal Reserve Requirement, which limits the

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9 June 29 Order, P 160 (“We therefore propose that PJM adapt its current FRR option to allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time.”)
amount of resources from outside an LDA that can be used based on a fair share of the available transmission capacity. This same approach can be used to ensure that the commensurate loads associated with RCO resources respect a fair apportionment of limited transmission capacity.

30. Finally, witness Keech claims that PJM’s proposal for in-auction clearing provides states flexibility for cross-state trading of Renewable Energy Credits (“RECs”), and additional flexibility in identifying commensurate loads, because the commensurate loads need not be identified until shortly before the delivery year. This last characteristic of PJM’s proposed approach could be convenient for some states, depending upon the particular challenges some states faces in making use of the mechanism. However, it could be inconvenient for other states, and for the FRR-RS resources, for whom it may create uncertainty about their compensation.

31. Witness Keech further asserts (p. 4) various disadvantages to removing the loads and resources from the auction, essentially repeating the arguments addressed above. The main difficulty results from PJM’s proposal to impose the RPM-cleared reserve margin on the commensurate loads; this becomes problematic if the loads and resources are removed from the auction. Since this proposal should be rejected, the difficulty it creates for approaches that remove resources and loads from the auction goes away.

32. The Commission should adopt the straightforward approach that it has already found workable and just and reasonable in the FRR context: removing from the RPM auctions the FRR-RS (RCO) resources and the commensurate loads based on the Forecast Pool Requirement located consistent with Minimum Internal Resource Requirements, per the current FRR rules.

10 RAA Schedule 8.1 Section D.5; see also the RPM Planning Parameters for each base residual auction, identifying the Minimum Internal Resource Requirement applicable to FRR resources in each modeled zone.
D. FRR-RS Resources and Commensurate Load in Different LDAs

33. As noted above, the FRR rules currently allow, but place limits upon, the amount of FRR resources located outside of an FRR entity’s LDA that may be included in the entity’s FRR Plan. As discussed in my Initial Affidavit, the restrictions ensure that an FRR entity uses no more than its “fair share” of an LDA’s transmission capacity (“CETL”), which may be valuable to access capacity resources located outside of the LDA that may be lower cost.

34. The same concept – that all loads should have access to only a fair share of CETL – can be imposed on FRR-RS commensurate loads. To see how this can be accomplished, consider the following numerical example. Consider an LDA with a 20,000 MW Reliability Requirement and 4,000 MW CETL. The Minimum Internal Resource Requirement (“MIRR”), reflecting a fair share of the CETL, would be 80%. Suppose one state represents 10,000 MW (half) of the LDA. The state’s share of the CETL would then be 2,000 MW. The state could use up to 2,000 MW of out-of-LDA FRR-RS resources matched to commensurate in-state load. With the remaining state load met by in-state and in-LDA resources, the 80% MIRR would be respected at the state level, with all loads (in and out of the state and LDA) treated fairly.

35. The PJM Submission claims (p. 58) that witness Keech testifies that FRR-RS resources and commensurate loads would have to be “co-located” to be removed from the auction. This is false; Witness Keech only mentions a co-location requirement as “one option” (P 15). The approach described above allows FRR-RS resources to be associated with commensurate loads in a different location subject to appropriate limits, and the approach is consistent with removal or in-auction clearing of FRR-RS resources and loads.
IV. Capacity Repricing (PJM’s “Extended RCO”) and Variants, Including CASPR

A. RPM Price Signals Will Be Accurate Without Repricing

36. PJM takes the position that its proposed MOPR, together with its RCO proposal, meets the requirements of the June 29 Order (PJM Submission, p. 8):

“The expanded MOPR, coupled with the Resource Carve-Out as proposed here, offers the Commission a defensible FPA-compliant path to accept and limit the trade-off that comes from recognizing subsidized, and hence uneconomic, resources as PJM capacity.”

37. Despite this position, PJM offers the “Extended RCO” capacity pricing proposal “additionally, for the Commission’s further consideration…” (p. 8). This subsection explains why repricing is not needed to ensure appropriate RPM price signals, and in fact will harm rather than improve the price signals.

38. In my Initial Affidavit I discussed how RPM is designed with a sloped demand curve to signal the need (or lack of need) for incremental resources. The RPM clearing price signal at any time reflects the balance of capacity supply and capacity demand. With the sloped demand curve, imbalances are self-correcting; a low price will discourage entry, leading to tighter capacity and higher prices, while a shortage results in high prices and stronger incentives for entry.

39. In evaluating capacity market design elements, the well-established approach has been to model the dynamic performance over time, using the model designed by Professor Benjamin F. Hobbs (discussed in my Initial Affidavit11), or a more recent model by The Brattle

11 Initial Affidavit, pp. 15-16.
In contrast, the various arguments now made about sponsored resources and “price suppression” employ a simple, static, single-auction analysis in which the supply curve is held constant.

40. In its October 2 comments, PJM does not present an argument that sponsored resources affect price signals from a longer-term, dynamic perspective. The closest PJM comes is in the Chao Affidavit, p. 4:

“With all else equal, a subsidized offer tends to suppress price as the seller is able to offer below its economic costs, which will tend to reduce the clearing price below the efficient level that would be set by economic offers, giving rise to market distortions that reduce the long-run efficiency and the social value of the market. The adverse economic effects associated with subsidies are well-documented in the peer-reviewed economic literature on, and modeling of, wholesale electric capacity markets.[fn 3]”

41. Dr. Chao does not present an argument that subsidized offers suppress prices (that is, RPM price signals) over the long term, nor do the references in footnote 3. The first reference is to a paper by David P. Brown of the University of Alberta. Brown states, “I find that subsidized entry reduces the equilibrium price paid for capacity”, he leaps to this big conclusion based only on solving a very small, two-stage game, in which he evaluates a single entrant’s offer strategy holding all other entrants’ strategies fixed (pp. 213-214). Even a more realistic two-stage model, in which all entrants must simultaneously choose their bidding strategies, is “left for future research” (p. 213, footnote 39). In addition, Dr. Brown’s solution and

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conclusion also rest upon the assumption that subsidized entry lowers energy market earnings (p. 210, “Assumption 3”), although he also asserts that the results might hold without that assumption (p. 214, footnote 41). Thus, this paper, containing only a simple, two-stage model, does not evaluate or simulate long-term equilibrium impacts and prices. It is not a dynamic analysis, such as Prof. Hobbs’ model, in which entrants are forecasting future energy and ancillary services earnings, taking into account the impacts on energy prices of already-cleared capacity quantities for the next three years, load uncertainty, and other considerations. The second reference focuses on resource adequacy (rather than price) outcomes, while the third reference surveys the literature and describes a dynamic modeling approach for assessing the impacts of subsidies, but does not create or solve the proposed model.

42. The only other attempt to argue that sponsored resources can have long-term impacts on RPM price signals was by Robert B. Stoddard in an affidavit on behalf of NRG Power Marketing LLC. Mr. Stoddard describes Prof. Hobbs’ model, and then states (p. 11), “While the Hobbs model did not model how subsidies to capacity would affect the market, it is not a difficult thought experiment.” He then explains that if sponsored entry exceeds the demand for capacity based on load growth plus retirements, capacity prices will be suppressed, that is, below the level required to attract entry. But under this circumstance, there is no need for merchant entry; if the RPM price was not “suppressed” (below Net CONE), it would be an inaccurate price signal and confusing to investors.

43. Mr. Stoddard also suggests (p. 11) that if investors perceive elevated risk due to subsidies and poor market design, this can lead to risk premiums and higher offer prices. As a general matter, entry subsidies can have negative long-term impacts on markets and consumers if
they create regulatory uncertainty for investors, as I have many times argued.\(^{14}\) However, note that this argument predicts higher, not lower, long-term prices, if investors perceive a significant regulatory risk.

44. Various commenters also promote a domino theory, suggesting that subsidies can become “contagious” and lead to more and more subsidies.\(^{15}\) However, this fails to recognize that states generally support certain resources in pursuit of legitimate policy objectives (such as to value environmental attributes not captured in the PJM markets), not simply to cover alleged revenue shortfalls.

45. Some commenters oppose implementing FRR-RS, and/or argue for capacity repricing, asserting that if FRR-RS resources and commensurate loads are removed, RPM would become a “balancing” or residual market. They assert that this could lead to less competitive or efficient outcomes, with more volatile prices.\(^{16}\)

46. However, it has always been the case that only a small fraction of all the resources cleared in RPM participate in any meaningful manner in RPM price formation. The vast majority of RPM resources are offered at zero or at prices sufficiently low that they are assured of clearing, while a small quantity is offered at very high prices that are extremely unlikely to clear. The remaining group of resources – offered at prices for which clearing is truly uncertain – has always been small, although it is somewhat larger since the implementation of Capacity Performance with the elimination of meaningful offer price caps. Removing inframarginal or extramarginal resources that were not participating in price formation would have no impact on the relevant


\(^{15}\) See, for instance, Stoddard Affidavit, p. 11.

\(^{16}\) See, for instance, Russo Affidavit, p. 10.
portion of the RPM supply curves, and sponsored resources would generally fall into these two
groups.

47. Figure 13 from The Brattle Group’s 2018 Quadrennial Review report, reproduced
here, illustrates recent RPM supply curves (“smoothed” somewhat, to eliminate any risk of
revealing specific offers). This graphic suggests that a total of about 180,000 MW was offered in
the most recent auction shown, of which roughly 150,000 was offered below about $70/MW-day
(and, accordingly, nearly certain to clear), while a small fraction was offered at prices above
$200/MW-day and very unlikely to clear. Therefore, less than 30,000 MW, or about 16% of all
capacity in the auction, was offered at prices such that there was much uncertainty about whether
the resource would clear. (Furthermore, a considerable portion of even this small quantity of
capacity was likely offered from large portfolios, such that the owner would benefit by failing to
clear some capacity, if that were to contribute to a higher clearing price earned by the rest of the
owner’s portfolio.)

48. Thus, vast majority of resources cleared through RPM have always been
“inframarginal” and not participated meaningfully in price formation, and removal of some of this
capacity from the auction (along with commensurate load) cannot be expected to have an
appreciable impact on RPM clearing prices or competitiveness. RPM dynamics will ensure that
with entry and exit over time, prices will hover around true Net CONE; any imbalances in the
short-term will be self-correcting. Any repricing approach, while addressing alleged short-run
“price suppression,” may only affect prices temporarily, until entry and exit restore the
equilibrium. The only enduring impact of repricing would be the chronic excess and duplicative
capacity that results from prices that misrepresent the true supply/demand balance.
B. “Extended RCO” – Description and Comparison to Capacity Repricing

49. As noted above, PJM believes the Commission can accept its proposed MOPR and RCO option with any capacity repricing provision. However, PJM nevertheless puts forward for “consideration” a new capacity repricing proposal (now called “Extended RCO”, although it was still called “repricing” as recently as August 15, 2018\textsuperscript{17}).
50. PJM’s witness, Dr. Hung-po Chao, does not argue that Extended RCO is needed and should be implemented (Chao Affidavit, p. 4; “I am not addressing whether the RCO, standing alone, will cause price suppression at a level that warrants corrective action.”). Nor did he design the Extended RCO; instead, it was developed by PJM for Commission consideration, with his “advice and input” (p. 3). Nor does Dr. Chao testify with regard to the quality of the prices that would result from Extended RCO, that is, whether Extended RCO would lead to accurate price signals. His affidavit focuses on the Infra-Marginal Rent payments that have only recently been added to PJM’s repricing proposal.

51. PJM’s new Extended RCO repricing proposal has the following elements (PJM Submission, pp. 65-67, pp. 71-75):

1. It begins with the base residual auctions as described above, with the RCO resources and commensurate loads kept in the auction, and the RCO resources offered at a zero price. This auction solution serves as the “Stage 1” solution that determines which resources will receive capacity commitments. (If the RCO/FRR-RS resources and loads were instead removed from the auction, clearing prices would be similar or the same, and the auction result could serve equally well as the Stage 1 for PJM’s new repricing proposal.)

2. In the Stage 2 Repricing run, the RCO resources are now completely removed from the auction, but the commensurate loads remain. The auction is then solved to determine clearing prices, and these Stage 2 prices will be paid to the non-RCO resources that cleared in Stage 1.

3. Non-RCO resources that failed to clear in Stage 1 and will not receive capacity commitments, but that offered at prices below the Stage 2 clearing prices, would
all receive Infra-Marginal Rent ("IMR") payments based on the difference between the Stage 2 clearing price and the resource’s offer price. PJM’s proposal does not impose any conditions or obligations to these payments.

4. The total cost of the IMR payments would be allocated to the RCO resources on a pro-rata basis; that is, the RCO resources (and, ultimately, the consumers in the states that sponsor them) would fund the IMR payments.

52. The new Extended RCO repricing proposal differs from PJM’s Capacity Repricing proposal from Docket No. ER18-1314 in the following ways:

1. In Stage 1, RCO resources are included at a zero price, while MOPRed resources that do not elect RCO are included in the auction at their MOPR prices. (Under Capacity Repricing, all MOPRed resources were included at their voluntary, presumably low, offer prices.) In the unlikely event that nearly all MOPRed resources are able to use the RCO or FRR-RS option, this would be a small difference; if instead many MOPRed resources are unable to elect RCO, this is a substantial difference and would result in a much higher Stage 1 clearing price.

2. In Stage 2, RCO resources are removed from the auction; under the Capacity Repricing proposal, these resources were included at their MOPR prices. This could be a significant difference, as it could result in Stage 2 clearing at prices even greater than the MOPR offer prices.

3. The new proposal includes the IMR payments and their allocation to RCO resources; there were no such provisions in the Capacity Repricing proposal.
C. Price Signals, and the Repricing “Disconnect”

53. The June 29 Order objected to PJM’s Capacity Repricing proposal, noting that it disconnected the determination of price and quantity, a “vital market fundamental” (P 64):

“We agree with intervenors that, by setting a clearing price that is disconnected from the price used to determine which resources receive capacity commitments, the market clearing price under Capacity Repricing will send incorrect signals, leading to greater uncertainty with respect to entry and exit decisions.”

54. PJM’s new Extended RCO capacity repricing proposal has an even more serious “disconnect” than the one the Commission objected to in the June 29 Order. In PJM’s Capacity Repricing proposal, both auctions runs included the same loads and resources, but different resource offer prices were used in the second run for some resources, thus the “disconnect.” Under Extended RCO, the two auction runs include the same loads, but different resources (the RCO resources are removed from the second stage). Thus, PJM’s new proposal results in a complete mismatch, or “disconnect”, between the demand and supply sides of the auction in the Stage 2 pricing run. This is conceptually the same as an auction where the loads represent the entire PJM footprint, but only resources located in, say, New Jersey are permitted to offer. The Extended RCO proposal would again reflect a disconnect that sends an incorrect price signal and misrepresents the need for resources, and it should be rejected on this basis alone.

55. Under PJM’s proposal, prices are set in Stage 2 as if the FRR-RS resources do not exist. Accordingly, RPM would send price signals that essentially attract and compensate duplicative capacity in an amount roughly equal to the FRR-RS quantity; and should the amount of FRR-RS capacity increase over time, the amount of duplicative capacity attracted by this proposal would similarly increase.
D. Infra-Marginal Rent Payments

56. Dr. Chao acknowledges that subsidies can be justified in certain circumstances, and can be a second-best policy intervention (p. 2). He also notes (p. 3) that a state policy tailored to address a market imperfection or externality (such as carbon emissions) is not considered a market distortion. However, he then proceeds to discuss state subsidies assuming they are unjustified and distorting support for “uneconomic” resources, resulting in displacement of “economic” resources and resulting “dead-weight losses” (pp. 5-6). These assumptions are incorrect, but are necessary to justify paying Infra-Marginal Rents to the displaced resources, and imposing the cost of the program on the RCO resources.

57. The idea of offering some of the losers in an auction substantial payments based on a side calculation, with no obligations attached to the payments, is quite novel. I am not aware of any auction, market, or market-like mechanism where such payments are available. Nor does Dr. Chao identify any precedent for this unknown and untried market design proposal.18

58. The new IMR payments are apparently included to address the two incentive problems I identified in my Repricing Affidavit (pp. 26-37), which problems had been known and frequently discussed for years.19 However, the IMR payment proposal introduces new incentive and gaming problems. Dr. Chao explains how paying IMR addresses the incentive problems that existed under the Capacity Repricing proposal, but acknowledges that the new proposal could also be susceptible to gaming (p. 7, footnote 6):

18 It could be suggested that the IMR payment proposal bears some similarity to ISO New England’s “CASPR” (Competitive Auctions with Sponsored Policy Resources) mechanism, but PJM makes no such claim, which would be incorrect – the opportunity for auction losers under CASPR is much more limited and restricted. In any case, CASPR, too, is a novel and as yet untested concept.

19 The history of PJM’s repricing concept and discussions around its known flaws were discussed in my Repricing Affidavit, pp. 19-20, 32-34.
“Obviously, the possibility of gaming is sensitive to market conditions. In the presence of market power or collusion, for example, one cannot rule out the possibility that resources may be able to influence market outcomes and increase profits by making offers that deviate from their truthful costs.”

59. Dr. Chao does not describe any potential incentive or gaming issues with the proposal, other than to recognize market power as quoted above. However, PJM’s proposal would allow IMR payments under the following circumstances:

1. Resources that intend to retire before the delivery year could nevertheless participate in the RPM auction in order to receive the IMR payment.

2. Planned resources that are eligible for the delivery year could also receive IMR payments, even if the developer has no intention to actually build the resource in time. In fact, a developer could offer the same resource year after year, receiving IMR payments and never beginning construction.

3. Resources could receive IMR payments, and also clear in a later Incremental Auctions for the same delivery year, to be paid twice for the same delivery year.

60. PJM’s novel market design feature is undoubtedly susceptible to other unanticipated and unintended opportunities and consequences.

61. PJM’s proposal for IMR payments to resources that take on no obligations is especially curious given PJM’s expressed concerns about “speculative” offers in base residual
auctions. In a filing of proposed changes to its incremental auction (“IA”) rules last spring, PJM stated as follows:20

“PJM’s current market rules do not protect against, and may in fact incentivize, speculative behavior. Specifically, the current rules allow Capacity Market Sellers to take on a commitment in the BRA with the opportunity to replace such BRA commitments in the IAs likely at a profit. This can encourage Capacity Market Sellers to offer in the BRA resources that have little or no reasonable expectation of physical delivery.”

62. Under PJM’s Extended RCO proposal, Capacity Market Sellers can receive IMR payments in the base residual auction without taking on any commitment, and earn guaranteed profits that are not dependent on replacing a commitment in incremental auctions. This should raise a much greater concern about so-called “speculative” offers from resources that may have “little or no reasonable expectation of physical delivery.”

63. Market power is, of course, endemic in RPM, so participants with large portfolios will have the ability and incentive to bid high, in order to economically withhold from the second stage of the auction resources that they do not expect to clear in the first stage. Such a strategy will be attractive because it will raise the RPM and IMR prices that will be paid to other resources in the portfolio (which under the new proposal, includes all resources offering below the Stage 2 price, not just those clearing in Stage 1).

64. As with PJM’s earlier Capacity Repricing proposal, the gaming opportunities are increased to the extent the “wedge” between the Stage 1 and Stage 2 prices is relatively large and predictable. This wedge will be larger if the quantity of FRR-RS resources grows, and it will be reasonably predictable if RPM is at all stable, which is of course to be hoped.

20 PJM, Proposed Changes to Incremental Auction Rules, filed March 9, 2018 in Docket No. ER18-988, p. 6.
65. Nor would the problems with the Extended RCO proposal be repaired by including the RCO resources in the Stage 2 auction run at their MOPR prices (as under the earlier Capacity Repricing proposal, and as Mr. Stoddard proposes; p. 22). This would simply recreate the original “disconnect” that the Commission has already rejected.

E. Potential Price and Cost Impact of “Extended RCO”

66. Extended RCO should be rejected because it is not needed and would result in distorted and misleading price signals contributing to excess and duplicative capacity. It would also lead to gaming to earn payments while providing no service. The proposal would also substantially raise the cost of capacity to customers, at least in the near term before the market adjusts to the distorted price signals by providing the additional, unneeded capacity it calls for.

67. Table 2 summarizes the potential price impact of Extended RCO, applying the simple, static-type analysis so popular with many commenters in this proceeding, and focusing on just the RTO Region. This analysis is based on the parameters for the May 2018 base residual auction for the 2021/22 Delivery Year, and uses a supply curve with a slope consistent with the results of PJM’s sensitivity analysis of the auction.

68. The first block of results in Table 2 shows the impacts of Extended RCO, assuming 5,000 MW of FRR-RS (RCO). The first row shows the “Stage 1” clearing result with either FRR-RS resources and loads included in the auction (per PJM’s proposal), or removed (per the June 29 Order). The second row shows the RPM cost associated with Stage 1, reflecting the fact that the FRR-RS resources do not earn the RPM price (additional capacity cost would be associated with the FRR-RS resources and presumably incurred by the commensurate loads).

69. The third row shows the “Stage 2” clearing result when the FRR-RS resources, but not the commensurate loads, are excluded from the second run of the auction software. In the
5,000 MW case, the RPM cost rises by over $2 billion compared to the base case without Extended RCO, before factoring in the IMR payments. The quantity on this third row reflects the removal of the FRR-RS resources but inclusion of the “tweener” resources that did not clear in Stage 1, but offered below the Stage 2 price, and will receive IMR payments.

<table>
<thead>
<tr>
<th>Table 2: Potential Price and Cost Impacts of &quot;Extended RCO&quot;</th>
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<tr>
<td>RPM Qty (MW)</td>
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<tr>
<td>-----------------</td>
</tr>
<tr>
<td><strong>5,000 MW FRR-RS:</strong></td>
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<tr>
<td>Base Case (Stage 1; FRR-RS is in auction)</td>
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<tr>
<td>Base Case (for cost; FRR-RS excluded)</td>
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<tr>
<td>Stage 2 (FRR-RS excluded) result</td>
</tr>
<tr>
<td>IMR quantity, average price; cost</td>
</tr>
<tr>
<td>IMR per unit FRR-RS ($/MW-day)</td>
</tr>
<tr>
<td>Upper bound IMR per unit FRR-RS</td>
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<tr>
<td><strong>9,000 MW FRR-RS:</strong></td>
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<tr>
<td>Base Case (Stage 1; FRR-RS is in auction)</td>
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<tr>
<td>Base Case (for cost; FRR-RS excluded)</td>
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<td>Stage 2 (FRR-RS excluded) result</td>
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<tr>
<td>IMR quantity, average price; cost</td>
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<tr>
<td>IMR per unit FRR-RS ($/MW-day)</td>
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<tr>
<td>Upper bound IMR per unit FRR-RS</td>
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</tbody>
</table>

Note: IMR estimate based on a linear supply curve between the Stage 1 and 2 clearing points; the upper bound estimate assumes a horizontal supply curve between these points.

70. The fourth row shows the quantity that will receive IMR payments and the average payment, assuming the supply curve is linearly increasing between the Stage 1 and Stage 2 clearing points. The IMR cost is modest, but becomes significant on a per MW-day basis as allocated to the FRR-RS quantity (as shown on row 5). Row 6 shows the upper bound for the IMR cost per
MW of FRR-RS, which would occur if the supply curve is horizontal between the Stage 1 and Stage 2 clearing points, and then vertical at the Stage 2 clearing point.

71. The second block of results in Table 2 show the impacts of Extended RCO with 9,000 MW of FRR-RS, under this same static approach (holding conduct and everything else constant). Under this scenario, Extended RCO increases the clearing price by almost $100/MW-day, and the RPM cost rises by over $5 billion. The IMR costs roughly double compared to the 5,000 MW case.

72. Of course, if Extended RCO were to be implemented, left in place, and considered credible by market participants and investors, and if “true Net CONE” is in the $140/MW-day range (as suggested by average RTO Region RPM clearing prices over the past several auctions), we would expect additional capacity to be offered to the point where the Stage 2 price is driven down close to the true Net CONE level. Should this occur, the quantity of resources receiving IMR payments would be close to the FRR-RS quantity (a bit smaller, due to the sloped capacity demand curve), indicating almost as much duplicative capacity receiving IMR payments as there is FRR-RS capacity.

73. Consequently, in addition to being unnecessary and resulting in distorted price signals, Extended RCO would also likely be very costly to consumers, at least in the short run.

F. Other Repricing Variants, Including CASPR

74. Commenters promote variants of repricing, including variants of ISO New England’s “CASPR” (Competitive Auctions with Sponsored Policy Resources) mechanism.21 In particular, Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, with an affidavit by

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21 162 FERC ¶ 61,205 Order on Tariff Filing, issued March 9, 2018 in Docket No ER18-619, P. 85.
Christopher J. Russo, promote a variant of CASPR called CaPSS. The Commission should ignore this and other such proposals and continue on the path set in the June 29 Order.

75. As a preliminary observation, I note that CASPR is a variant of repricing. Under CASPR, there is a primary auction and a substitution auction. The primary auction effectively serves as the “Stage 2” auction that determines the clearing price, but not necessarily which resources will provide capacity. Under CASPR, in the primary auction, sponsored resources are MOPRed and not accommodated in any manner, as in PJM’s “Stage 2” auction. The CASPR substitution auction can allow some MOPRed resources that failed to clear in the primary auction to take on the capacity supply obligations of resources that cleared in the primary auction but are willing to commit to retire.

76. CASPR resulted from an extended stakeholder process that involved over 500 pages of presentations by ISO New England and stakeholders. While CASPR and its many details were very controversial, painstaking, multilateral negotiations ultimately led to a package that most stakeholders could either support or not oppose. However, I note that when stakeholders support such an outcome, it does not necessarily mean they like it, it just means they prefer it to what they fear they would otherwise get.

77. CASPR remains, of course, untested and unproven, and ISO New England’s external market monitor believes the design contains a “critical design flaw” that will lead to inefficient investment and retirement decisions and raise costs substantially over the long term.22 Various CASPR details are still being discussed in recent ISO New England stakeholder meetings.

78. PJM and stakeholders considered but declined to develop a CASPR-like approach, first in the CCPPSTF stakeholder process, and again last summer in discussions following the June 29 Order. The Commission should respect these decisions and not push PJM toward CASPR or CaPSS, for a number of reasons.

79. First, a quick review of the CaPSS proposal suggests that it would likely result in very little demand in the proposed substitution auction and, as a result, the proposal would fail to accommodate state sponsored resources to any reasonable degree (an outcome that likely would be satisfactory to Vistra and many other capacity sellers).

80. Second, there are substantial differences between PJM and New England, and CASPR was the result of lengthy negotiations that were very difficult, very detailed, and very peculiar to the New England circumstances. Differences between the PJM and New England markets, resources and tariffs relevant to the design of CaPSS or CASPR include the following, among many others: zonal structure (PJM has many more zones, and multiple levels of nesting); retirement rules (New England has capacity market retirement bids that require a resource to retire; PJM has no such provisions); sponsored resource types (in New England it is all about zero carbon resources, while in PJM concerns about subsidized coal units have been a major driver); pace of new entry (in PJM there has been substantial new entry, in New England incentives for new entry are a more significant concern); capacity demand curve location (in New England the demand curve equals the reliability requirement at Net CONE, while PJM’s demand curve is well in excess of the reliability requirement at Net CONE).

81. Third, while Vistra and its expert claim that CaPSS is similar to CASPR, the proposal is very different, partly reflecting differences between the PJM and New England markets, resources, and tariffs, but also reflecting provisions Vistra has apparently included to
further reduce the extent to which the proposal would accommodate sponsored resources. Differences between the CaPSS proposal and CASPR include the following details: expansion of the definition of Material Subsidy to include resources that “seek” a subsidy, and to include federal subsidies; allocating the side payments from the substitution auctions to supply rather than loads; allowing a broader class of resources (including, for example, MOPRed coal plants) to participate in the substitution auction as supply; and limitations on inter-zonal transfers of capacity supply obligations.

82. Finally, the CaPSS proposal includes some other CASPR details that may not be workable or acceptable in the PJM context, such as the following: treating supply offers in the substitution auction as rationable; restrictions on inter-zonal substitutions; and excluding new (unbuilt) resources from the substitution auctions.

83. Capacity repricing, including CASPR or any variant thereof, is not necessary and would be harmful and costly. The Commission should continue on the path set in the June 29 Order, with a non-discriminatory resource-specific FRR alternative and without capacity repricing in any form.

84. This concludes my affidavit.
Exhibit H
Motion to Apply Ethics Guidance to Proceedings, January 11, 2019
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation et al., Complainants )
) Docket Nos. EL16-49-000
v.
) PJM Interconnection, L.L.C. )
) )
) PJM Interconnection, L.L.C. ) ER18-1314-000
) ER18-1314-001
) )
) PJM Interconnection, L.L.C. ) EL18-178-000
) (Consolidated)
) )
) ISO New England Inc. ) Docket Nos. ER18-1509-000
) EL18-182-000
) )
) ISO New England Inc. ) ER18-2364

Motion to Apply Ethics Guidance to Proceedings

Regulatory Commission (“Commission” or “FERC”), 18 C.F.R. § 385.212 (2016), Natural
Resources Defense Council, Sierra Club, and Union of Concerned Scientists, collectively “Clean
Energy Advocates,” respectfully request the Commission, and Commissioner McNamee
specifically, apply the ethics guidance memorialized in the January 7, 2019 letter to Senator
Cortez Masto to the above proceedings. The guidance provided by Designated Agency Ethics
Officer (DAEO) Beamon directs that Commissioner McNamee recuse himself where a
proceeding “develop[s] in such a way as to replicate or closely resemble Docket No. RM18-1.”¹
Clean Energy Advocates do not contend that the above-listed proceedings currently address the


1
same factual or legal matters as those at issue in RM18-1. However, pending within each of these
dockets are requests by FirstEnergy Solutions Corp. and/or FirstEnergy Utility Companies
(collectively, “FirstEnergy”) to provide special compensation to certain “fuel secure” units to
prevent their retirement.\textsuperscript{2} To the extent that the Commission considers those pending requests to
be within the scope of the above-listed proceedings, the proceedings would then “replicate or
closely resemble Docket No. RM18-1” and, by the terms of the DAEO’s guidance, require
Commissioner McNamee’s recusal. While it is not our view that such recusal is required today,
we file this motion as a precautionary measure to make clear that the terms of the ethics guidance
apply to these proceedings in the event that the FirstEnergy requests are taken under
consideration by the Commission. Under that contingency, Clean Energy Advocates request that
Commissioner McNamee recuse himself as provided by the ethics guidance.

**Statement of Relevant Facts**

Commissioner McNamee was confirmed by the Senate on December 6, 2018, and sworn
in to the Commission on December 12, 2018.\textsuperscript{3} Shortly after his confirmation, the Harvard
Electricity Law Initiative filed comments in support of Commissioner McNamee’s recusal from
dockets RM18-1 and AD18-7.\textsuperscript{4} On December 18, 2018, Clean Energy Advocates filed a motion

\textsuperscript{2} Renewed Request for Emergency Action of FirstEnergy Solution Corp., ER18-1509,
EL18-154, AD18-7 at 2 (June 15, 2018) (“FirstEnergy Renewed Request”) (“FES thus renews its
request that the Commission immediately adopt the proposal that FirstEnergy Service Company
filed in Docket No. RM18-1-000”); Comments of FirstEnergy Utility Companies, EL16-49,
ER18-1413-000/001, EL18-178 (Nov. 26, 2018) at 2 (“FirstEnergy Comment”) (“FE Utilities
request that the Commission protect customers by preserving fuel-secure, resilient generation at
risk of premature retirement with cost-based, short-term, RMR-like agreements.”).

\textsuperscript{3} “Senate Votes to Confirm McNamee to FERC,” FERC Press Release (Dec. 6, 2018),
available at \url{https://www.ferc.gov/media/news-releases/2018/2018-4/12-06-18.asp#.XBUsFGhKg2w} ; see also, About Commissioner Bernard L. McNamee, available at:
\url{https://www.ferc.gov/about/com-mem/McNamee.asp}.

\textsuperscript{4} Harvard Electricity Law Initiative Comment, RM18-1, AD18-7 (Dec. 6, 2018).
requesting recusal from the same two proceedings. On January 7, 2019, Commissioner McNamee submitted a letter in response to a request by Senator Cortez Masto, which attached a memorandum summarizing advice provided by DAEO Beamon. The ethics guidance did not require Commissioner McNamee to immediately recuse himself from docket AD18-7. It instead cautioned “continued oversight to ensure that Docket No. AD18-7 does not develop in such a way as to replicate or closely resemble Docket No. RM18-1” which would require Commissioner McNamee’s recusal. For matters beyond AD18-7, the guidance advised Commissioner McNamee to seek specific guidance “on any matter related to your past statements, positions, work, or any other concerns that you may have.”

Consolidated dockets no. EL16-49, ER18-1314-000, ER18-1314-0001, and EL18-178 is an ongoing proceeding addressing potential tariff changes to the PJM Interconnection, LLC (PJM) capacity market rules, including modification of the Minimum Offer Price Rule (MOPR) and adoption of a fixed resource requirement (FRR) alternative. The proceeding resolves a complaint filed under section 206 of the Federal Power Act by Calpine Corporation and a group of other generators in March 2016. Complainants argued that the new threat of the capacity market bidding incentives created by a generous retail rate-recovery mechanism warranted

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5 The motion set forth facts relevant to the Commission’s consideration of Commissioner McNamee’s recusal, including his prior work on behalf of the Department of Energy in support of two proposals to prevent the retirement of so-called “fuel secure” resources. We incorporate that statement of relevant facts by reference. Motion for Recusal of Commissioner McNamee, RM18-1, AD18-17 (Dec 18, 2018).
6 Ethics Guidance, supra note 1 at 2.
7 Id. at 6.
8 The complaint focused on the alleged market impacts of a then-proposed action by the Public Utilities Commission of Ohio to allow approximately six gigawatts of capacity owned by AEP and FirstEnergy subsidiaries to recover costs under proposed affiliate power purchase agreements (“akin to traditional cost-of-service, rate of-return regulation”) from retail ratepayers. Calpine Corp. Complaint Requesting Fast-Tracking, EL16-49 at 25-26 (March 21, 2016).
extension of the MOPR, which only applied to new gas-fired resources, to existing units of all types participating in the capacity market. The complaint was ultimately consolidated with a section 205 filing by PJM proposing two alternate tariff changes modifying the scope of the MOPR. In a June 2018 Order, the Commission rejected PJM’s proposals, granted the Calpine Complaint in part, issued a finding that PJM’s capacity market is not just and reasonable, and initiated sua sponte a section 206 proceeding. On November 26, 2018, FirstEnergy filed a comment in the consolidated docket requesting that “the Commission expand the scope of this Section 206 proceeding,” including by putting in place interim measures to “preserv[e] fuel-secure, resilient generation at risk of premature retirement with cost-based, short-term, RMR-like agreements.”

Consolidated docket nos. ER18-1509 and EL18-182 involve a petition for waiver of certain tariff provisions filed by ISO New England, Inc. (ISO-NE) to permit the ISO to retain two retiring generating units for fuel security purposes. In a July 2018 Order, the Commission denied the requested waiver and instituted proceedings under section 206 of the Federal Power Act (EL18-182), preliminarily finding that the ISO-NE tariff is not just and reasonable based on evidence that the tariff failed to address specific regional fuel security concerns. The Commission directed ISO-NE to submit interim tariff revisions by August 31, 2018, and permanent tariff revisions to improve its market design to better address regional fuel security

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9 Id. at 2.
11 FirstEnergy Comment, supra note 2 at 2-3.
concerns by July 1, 2019, or to show cause why the tariff remains just and reasonable absent those changes.\textsuperscript{13} On August 31, 2018, ISO-NE filed its interim tariff revisions in dockets EL18-182 and ER18-2364, and on December 3, 2018, the Commission entered an order approving those revisions.\textsuperscript{14} Requests for rehearing of the Commission’s approval of those tariff revisions remain pending, and ISO-NE has yet to file permanent tariff changes pursuant to the July 2018 Order.

FirstEnergy filed a “renewed request for emergency action” in ER18-1509, prior to the Commission’s initiation of section 206 proceedings in EL18-182.\textsuperscript{15} In the filing, FirstEnergy “renews its request that the Commission immediately adopt the proposal that FirstEnergy Service Company filed in Docket No. RM18-1-000 to ensure the continued operation of critical nuclear and coal-fired generators while a long term solution is developed.”\textsuperscript{16}

FirstEnergy’s initial filing in RM18-1 states it “strongly support[s]” the Department of Energy Notice of Proposed Rulemaking (“DOE NOPR”) “subject to certain limited modifications to ensure that fuel-secure, resilient generating facilities receive just and reasonable compensation for the value they provide to the electric grid.”\textsuperscript{17} FirstEnergy requested the Commission to require RTO/ISOs “to adopt specific tariff changes” providing that, “in exchange for a Resiliency Support Resource Unit remaining in operation and providing energy and ancillary services in times of need by the RTO/ISO, the RTO/ISO will ensure that the RSR Unit

\textsuperscript{13} Id. at 2.


\textsuperscript{15} FirstEnergy also filed this request in AD18-7 and NEGPA v. ISO-NE, ER18-154. Because NEGPA withdrew its original complaint in ER18-154, it is our understanding that docket is no longer active. FirstEnergy Renewed Request, \textit{supra} note 2.

\textsuperscript{16} Id. at 2.

\textsuperscript{17} Comments of FirstEnergy Service Co. et al. in Support of Grid Resilience Pricing Notice of Proposed Rulemaking, RM18-1 at 1 (Oct. 23, 2018).
receives a payment each month equal to its full costs of operation and service less market
revenues for capacity, energy, and ancillary services.” FirstEnergy’s proposal also adopted
nearly precisely the same eligibility criteria as the DOE NOPR, providing that resources with 90-
day fuel supply would be eligible for special compensation.¹⁹

Legal Background

Relevant legal background is set forth in the Clean Energy Advocates’ December 18, 2018 motion for recusal.

Argument

I. If the Commission takes up consideration of FirstEnergy’s requests, Commissioner McNamee must recuse himself.

Clean Energy Advocates contend that provision of special compensation for a broad class of resources on the grounds of their so-called “fuel security” is beyond the scope of the above-listed proceedings. The PJM proceeding is focused on the interactions between state policy and operation of the capacity market, as well as identifying an appropriate means to accommodate state policy and market objectives. The ISO-NE proceeding is narrowly focused on, in the interim, addressing alleged violations of reliability standards that would arise from retirements of particular units and, over the long-term, identifying tariff changes sufficient to ensure the market delivers adequate winter energy in light of seasonal fuel constraints. Provision of special, out-of-market compensation for a broader category of generating resources based upon their so-called fuel-secure characteristics is not responsive to the Commission’s respective section 206 findings in either proceeding.

¹⁸ Id at 4.
¹⁹ Id. at 40 (“FirstEnergy supports the 90-day fuel requirement set forth in the Proposed Rule”). FirstEnergy proposed some modifications to the DOE NOPR requirement that eligible resources be compliant with environmental laws. See id.
However, at least one party disagrees, and has directly requested that the Commission take up consideration of whether the PJM tariff and the ISO-NE tariff are not just and reasonable because retirement of uneconomic coal and nuclear generation threatens the bulk power system due to the loss of those resources so-called “fuel security.” FirstEnergy requests the Commission consider whether proposed tariff changes in PJM “contribute to excessive premature retirements of resilient generators” and, in ISO-NE, that it adopt “permanent fixes to the present threats posed by generation retirements.” Moreover, FirstEnergy requests that the Commission issue precisely the same relief proposed in RM18-1: cost-recovery for “fuel secure” resources to prevent their retirement. In the PJM proceeding, FirstEnergy requests the Commission mandate issuance of “cost-based, short-term, RMR-like agreements” for this category or resources, and FirstEnergy renews its earlier request in RM18-1 for monthly payments of these generators’ full costs in ISO-NE proceeding.

Resolution of these requests “replicates or closely resembles” the matters at issue in RM18-1. FirstEnergy seeks the same result (special compensation to so-called fuel secure resources so as to prevent their retirement), based on largely the same legal (existing market rates are not just and reasonable) and factual basis (retirements of uneconomic coal and nuclear units pose a threat to reliability and resilience of the bulk power system), as the Department of Energy in the grid resiliency pricing rule rejected in RM18-1.

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20 FirstEnergy Renewed Request; FirstEnergy Comment, supra note 2.
21 FirstEnergy Comment, supra note 2 at 2.
22 FirstEnergy Renewed Request, supra note 2 at 2.
23 FirstEnergy Comment, supra note 2 at 2.
24 FirstEnergy Renewed Request, supra note 2 at 2.
To the extent the Commission determines that it must take up consideration of these requests to resolve the proceedings, following the terms of DAEO ethics guidance, Commissioner McNamee must recuse himself from the proceedings.

CONCLUSION

For the foregoing reasons, Clean Energy Advocates respectfully request that the terms of the ethics guidance apply to these proceedings, and that Commissioner McNamee recuse himself in the event that the FirstEnergy requests are taken up for consideration by the Commission.

Respectfully submitted, January 11, 2019

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

/s/ Kim Smacznia

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January 11, 2019
Exhibit I
Motion Requesting Disclosure of the Basis for Non-Recusal or, in the Alternative, Recusal of Commissioner McNamee, September 9, 2019
Docket Nos. ER18-1314, EL16-49, EL18-178 (and consolidated cases)
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, et al. )

v. ) Docket No. EL16-49-000

PJM Interconnection, L.L.C. )

PJM Interconnection, L.L.C. ) Docket No. ER18-1314-000
) Docket No. ER18-1314-001

PJM Interconnection, L.L.C. ) Docket No. EL18-178-000
) (Consolidated)

MOTION REQUESTING DISCLOSURE OF THE BASIS FOR NON-RECUSAL OR, IN
THE ALTERNATIVE, RECUSAL OF COMMISSIONER MCNAMEE

Regulatory Commission (“Commission” or “FERC”), 18 C.F.R. § 385.212 (2016), Natural
Resources Defense Council and Sierra Club (collectively “Clean Energy Advocates”)
respectfully submit this motion requesting that Commissioner McNamee recuse himself from the
above-captioned dockets, or, in the alternative, explain how his participation is consistent with
due process and ethics obligations. As detailed below, as recently as 2017, Commissioner
McNamee was employed by McGuireWoods LLP, whose clients include three parties with
significant economic interests in the outcome of this proceeding— Dominion Energy Services,
McNamee has declined to participate in numerous dockets involving these parties.¹

Commissioner McNamee’s participation in a recent decision in this proceeding, however, reveals

¹ See Exhibit A, Non-Exhaustive List of McNamee Recusals (listing more than 20 dockets,
involving at least one of the three former clients, in which Commissioner recused himself).
that he has not recused himself\(^2\) despite his former clients’ clear economic interests in the outcome. If the Commission were to issue an order instituting tariff changes that directly and predictably affect the financial interests of Commissioner McNamee’s former clients, it would cause a reasonable person to question the impartiality of this proceeding. Recusal is called for under these circumstances even absent any finding of actual bias. Clean Energy Advocates thus request that Commissioner McNamee recuse himself from the proceeding. Maintaining public confidence in the integrity and impartiality of the Commission and its decisionmaking is essential, and recusal under these circumstances serves as an important safeguard of due process, rule of law, and perception of fairness. At minimum, Commissioner McNamee should explain his participation in this proceeding in light of the significant apparent conflicts. Clean Energy Advocates respectfully request that a written explanation for this determination be placed in the record.\(^3\)

**Statement of Relevant Facts**

This ongoing proceeding concerns the treatment of resources that receive out-of-market support in the capacity market operated by PJM Interconnection, Inc. (“PJM”). On March 21, 2016, a group of generation resource owners filed a complaint under Section 206 of the Federal Power Act (“FPA”)\(^4\) alleging that PJM’s tariff was unjust and unreasonable “because it does not include provisions to prevent the artificial suppression of prices by existing generation resources

\(^2\) See *PJM Interconnection, L.L.C.*, Order on Motion for Supplemental Clarification, Docket No. EL18-178-000 (McNamee, Comm’r, concurring) (July 25, 2019).

\(^3\) If Commissioner McNamee has obtained authorization to participate in these proceedings from the Commission’s designated ethics officer pursuant to 5 C.F.R. § 2635.502(d), Clean Energy Advocates respectfully request a written explanation for this determination.

\(^4\) 16 U.S.C. § 824e.
that are the beneficiaries of out-of-market revenues.”^5 While that complaint was pending, PJM itself filed two alternative sets of proposed tariff changes for its capacity market under FPA Section 205^6, intended to address the purported price-suppressive effects of resources receiving support from state policies.^7 On June 29, 2018, the Commission issued a consolidated order for both proceedings, finding that PJM’s capacity market was unjust and unreasonable because its existing market rules did not adequately address “the price suppressive impact of resources receiving out-of-market support,” rejecting the various replacement rates proposed by the generators and PJM.8 Accordingly, the Commission initiated sua sponte a proceeding under FPA Section 206 to find a just and reasonable replacement rate.9

At least three of Commissioner McNamee’s former clients are actively participating in this proceeding, and have engaged in the docket since 2016 through and including the period during which Commissioner McNamee represented clients at his former law firm, McGuireWoods, LLP. Dominion has intervened, submitted comments, and sought rehearing of a Commission determination in this proceeding on behalf of its public utility affiliate, Virginia Electric and Power Company d/b/a Dominion Virginia.10 Duke has also actively participated in

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^6 16 U.S.C. § 824d.

^7 PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000 (Apr. 9, 2018).


^9 Id. at PP 5–6.

the docket on behalf of itself and its affiliates from 2016 to the present. Direct Energy Business LLC ("Direct Energy"), which is wholly owned by Centrica PLC,\textsuperscript{11} has also participated throughout the proceeding and advocates for changes to PJM tariffs consistent with its financial interests.\textsuperscript{12} Both Dominion and Duke have advocated for exceptional treatment of their resources under the PJM capacity market rules that are the subject of this proceeding, and determination of the matters in the docket will incontrovertibly directly impact their financial interests. In its filings, Dominion has urged that any replacement rate distinguish between resources owned by “Integrated Public Utilities” subject to regulation by state public utility commissions (such as Virginia Electric and Power Company) from resources in restructured states, arguing that state-regulated utilities’ self-supply resources should not be subject to a revised minimum offer price rule (“MOPR”) or other mitigation in the capacity market.\textsuperscript{13} Dominion’s filings emphasize the importance of this MOPR exception to its financial interests, calling it “critical”\textsuperscript{14} and describing how equal application of MOPR to its resources may cause its resources to “not clear the market” and require it to “be forced to purchase capacity through the [Reliability Pricing Mechanism].”\textsuperscript{15} Likewise, Duke argues that, although state-regulated cost recovery through retail rates could be considered a “material subsidy” triggering the MOPR,

\textsuperscript{11} Centrica PLC also appears to be a client of McGuireWoods, LLP. See e.g., In the matter of: Sabine Pass Liquefaction, LLC, Motion to Intervene of Centrica PLC, FE Docket No. 13-42-LNG (Sept. 23, 2013), https://fossil.energy.gov/ng\_regulation/sites/default/files/programs/gasregulation/authorizations/2013/applications/Centrica13\_42\_lng09\_23\_13.pdf.

\textsuperscript{12} Calpine Corporation, et al. v. PJM Interconnection, L.L.C., Motion to Intervene and Comments of Direct Energy Business, LLC, EL16-49-000 (Apr. 11, 2016); PJM Interconnection, L.L.C., Comments of Direct Energy, EL18-178-000 (Oct. 2, 2019).

\textsuperscript{13} Dominion Comment at 3–4; see also Dominion Request for Rehearing at 16 (“Vertically integrated utilities should be exempt from price mitigation”).

\textsuperscript{14} Dominion Request for Rehearing at 7.

\textsuperscript{15} Dominion Comment at 15.
an exception should apply to the benefit of its resources.\(^\text{16}\) Duke further raised its concerns over the treatment of a particular power purchase agreement between the Ohio Valley Electric Corporation ("OVEC") and several companies, including one of Duke’s affiliates.\(^\text{17}\) Duke advocated for an even broader carve-out that would ensure that payments pursuant to the OVEC agreement would not trigger MOPR, to the financial benefit of its affiliate.\(^\text{18}\) Direct Energy, Inc. is generally supportive of an expanded MOPR with minimal exceptions, but advocates for changes to the reference price formula that would apply to existing resources newly affected by an expanded MOPR.\(^\text{19}\)

According to Commissioner McNamee’s Executive Branch Personnel Public Financial Disclosure Report submitted to the Office of Government Ethics, he was employed at the law firm McGuireWoods, LLP for a period including January 2016 to May 2017.\(^\text{20}\) The report indicates that Commissioner McNamee received over $5,000 in a year from Dominion for “[l]egal services to Dominion Energy Services’ affiliates Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (clients of McGuireWoods LLP).”\(^\text{21}\) Likewise, the report discloses that Commissioner McNamee received payments triggering reporting requirements from Direct Energy, Inc. for legal services as a client of McGuireWoods LLP.\(^\text{22}\) It is not clear whether Commissioner McNamee directly advised


\(^\text{17}\) \textit{Id.} at 5.

\(^\text{18}\) \textit{Id.} at 6.


\(^\text{21}\) \textit{Id.}

\(^\text{22}\) \textit{Id.}
Dominion or Direct Energy, Inc. on matters related to Docket EL16-49, the complaint that is the origin of this proceeding. Public records indicate that Commissioner McNamee advised and represented Dominion regarding cost-recovery for resources participating in PJM’s capacity market, resources that will be directly and predictably affected by the decision pending in this proceeding.  

After Commissioner McNamee was nominated by the President, he submitted a letter to the Commission’s DAEO detailing “the steps that I will take to avoid any actual or apparent conflict of interest” as a Commissioner. Among other things, Commissioner McNamee committed to signing the Ethics Pledge (Exec. Order No. 13770), and indicated that he understood that he is subject to the standards of ethical conduct for employees of the Executive Branch. Commissioner McNamee was confirmed by the Senate on December 6, 2018, and sworn in to the Commission on December 11, 2018.

Legal Background

Commission members are subject to several overlapping sets of ethical standards. Executive Order No. 13770 consists of an ethics pledge that every appointee to an executive

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25 Id.

agency is required to sign. Among others, it includes the following commitment: “I will not for a period of 2 years from the date of my appointment participate in any particular matter involving specific parties that is directly and substantially related to my former employer or former clients, including regulations and contracts.”

The Commission is also obligated to follow rules issues by the Office of Government Ethics (“OGE”). Under OGE’s regulation, 5 C.F.R. § 2635.502, an employee is prohibited from participating in matters in which an entity with whom the employee has had an attorney-client relationship in the past year, and in which the employee knows a reasonable person is likely to question his impartiality, without first obtaining approval from the Designated Agency Ethics Official (“DAEO”). In adopting these provisions, OGE recognized that “employees have long been obligated to act impartially and to avoid even the appearance of loss of impartiality” and sought to put in place “a specific mechanism to resolve difficult issues of whether, in particular circumstances, a possible appearance of loss of impartiality is so significant that it should disqualify them from participation in particular matters.” The Commission’s practice is to take steps to avoid even the appearance of impartiality, which have included recusal of individual commissioners in proceedings involving former clients or employers.

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28 Id. Executive Order 13770 defines a “former client” as “any person for whom the appointee served personally as agent, attorney, or consultant within the 2 years prior to the date of his or her appointment, but excluding instances where the service provided was limited to a speech or similar appearance. It does not include clients of the appointee’s former employer to whom the appointee did not personally provide services.”
29 18 C.F.R. § 3c.1.
31 See e.g., Letter from Kevin J. McIntyre to DAEO Charles A. Beamon (Aug. 22, 2017) (agreeing to recuse from all matters in which his former firm is a party or represents a party for one year pursuant to 5 C.F.R. § 2635.502(d)); Re Union Oil Co. of California, 23 F.P.C. 73, 77
Commission employees regularly recuse themselves from matters involving prospective employers. As DAEO Charles Beamon has described agency practice, “FERC . . . must prioritize integrity, impartiality, fairness, transparency, and due process in their proceedings” and participants in the proceedings must be “above reproach” avoiding “even the slightest appearance of impropriety.”

The above requirements safeguard not just public confidence in the integrity of government decision-making, but the constitutional right to due process as well. “A fair trial in a fair tribunal is a basic requirement of due process.” Due process protections apply to administrative agency adjudications, and mandate recusal not only where an adjudicator has a

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[33] Charles Beamon, Michael Korwin, & Jeffrey Pienta, Ethics Issues Common to Regulatory Agencies, Presentation at the 2014 National Government Ethics Summit, at Slide 4 (Sept. 23, 2014), https://www.oge.gov/web/OGE.nsf/0/7C20A2E3883343F78525815A0059B76A/$FILE/PR_Korwin_Issues%20Regulatory%20Agencies.pdf; see also FERC Chairman Kevin McIntyre Charges Full Steam Ahead, ENERGY BAR ASSOCIATION UPDATE (Chairman McIntyre described as cheerfully following these requirements for recusal because, as McIntyre explained, he is “very much a ‘rule of law’ guy.”), https://www.ena-net.org/assets/1/6/2018EBAMemberAuthoredArticleChairmanMcIntyreInterview.pdf.

[34] In re Murchisen, 349 U.S. 133, 136 (1955).

“direct, personal, substantial, pecuniary interest” that may affect her impartiality, but under any circumstances that create the “appearance of bias” or “probability of bias.” These protections are implemented by “objective standards that do not require proof of actual bias.” While such a “stringent rule” may sometimes demand recusal by adjudicators “who have no actual bias and who would do their very best to weigh the scales of justice equally between contending parties,” endeavoring to prevent “even the probability of unfairness” safeguards critical values including public confidence in the institution. As the Supreme Court succinctly explained: “To perform its high function in the best way ‘justice must satisfy the appearance of justice.’”

Recusal is required where “a disinterested observer may conclude that the [adjudicator] has in some measure adjudged the facts as well as the law of a particular case in advance of

36 Caperton v. A.T. Massey Coal Co., 556 U.S. 868, 876–77 (2009) (“the Court has identified additional instances which, as an objective matter, require recusal. These are circumstances “in which experience teaches that the probability of actual bias on the part of the judge or decisionmaker is too high to be constitutionally tolerable.”) (quoting Withrow, 421 U.S. at 47).

37 Mitchell v. Sirica, 502 F.2d 375, 382–83 (D.C. Cir. 1974) (“This circuit also has adopted the appearance of bias test, with specific reference to the prejudgment of issues in administrative agency disqualification cases.”) (citations omitted); Kennecott Copper Corp. v. F.T.C., 467 F.2d 67, 79–80 (10th Cir. 1972) (“The rule is that a Commissioner must be disqualified if he or she has prejudged the case or has given a reasonable appearance of having prejudged it.”).

38 Caperton, 556 U.S. at 883–84.

39 Id. at 883; Hurles v. Ryan, 752 F.3d 768, 789 (9th Cir. 2014) (must assess risk of bias “under a realistic appraisal of psychological tendencies and human weakness”) (internal quotation omitted).

40 Murchisen, 349 U.S. at 136; see Mistretta v. United States, 488 U.S. 361, 407 (1989) (“The legitimacy of the Judicial Branch ultimately depends on its reputation for impartiality and nonpartisanship.”); Wersal v. Sexton, 674 F.3d 1010, 1022 (8th Cir. 2012) (“maintaining the appearance of impartiality is systemic in nature, as it is essential to protect the judiciary’s reputation for fairness in the eyes of all citizens . . . public confidence in the judiciary is integral to preserving our justice system.”); Gilligan, Will & Co. v. SEC, 267 F.2d 461, 468–69 (2d Cir. 1959) (failing to address appearance of prejudgment opens “the Commission’s reputation for objectivity and impartiality” to challenge).

The standard is an objective one and focuses on an “average” decisionmaker without presumption of superior honesty or integrity. The factfinder need not determine, or even inquire, whether an adjudicator’s mind is actually closed on the matters at issue; recusal is called for where an “equally fair interpretation” of the circumstances reflects “prejudgment of a material issue.” In most circuits confronting the issue, the failure of even a single adjudicator on a multi-member body to recuse where due process so requires warrants reversal of the decision, regardless of whether the member affected by an appearance of bias is the deciding vote.

Additionally, due process considerations require that an adjudicator “who participates in a case on behalf of any party, whether actively or merely formally by being on pleadings or briefs take no part in the decision of that case by any tribunal on which he may thereafter sit.”

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43 Caperton, 556 U.S at 885 (“Due process requires an objective inquiry” into whether the circumstances “offer a possible temptation to an average judge.”) (Internal quotation omitted).

44 Mitchell, 502 F.2d at 387.

45 Berkshire Employees Ass’n of Berkshire Knitting Mills v. N.L.R.B., 121 F.2d 235, 239 (3d Cir. 1941) (“Litigants are entitled to an impartial tribunal whether it consists of one man or twenty and there is no way which we know of whereby the influence of one upon the others can be quantitatively measured”); Cinderella Career & Finishing Sch., 425 F.2d at 592 (no way of determining the extent to which one biased member’s views affect the deliberations of a supposedly impartial tribunal); Hicks v. City of Watonga, 942 F.2d 737, 748 (10th Cir. 1991) (concluding that the plaintiff could make out a due process claim by showing bias on the part of only one member of the tribunal); Wilkerson v. Johnson, 699 F.2d 325, 328–29 (6th Cir. 1983) (bias of one member of a four person application board sufficient to deny due process); Antoniu, 877 F.2d at 726 (vacating commission decision even though biased commissioner belatedly recused himself); Stivers v. Pierce, 71 F.3d 732, 748 (9th Cir. 1995) (“plaintiff need not demonstrate that the biased member’s vote was decisive or that his views influenced those of other members”).

46 Trans World Airlines, Inc. v. Civil Aeronautics Bd., 254 F.2d 90, 91 (D.C. Cir. 1958); see also Laird v. Tatum, 409 U.S. 824, 828–29 (1972) (standard for judicial disqualification includes merely signing a brief or pleading or actively participating even without signing a brief or
This legal principle is deeply rooted in the “venerable tradition” that no man shall judge his own cause.\textsuperscript{47} Cases upholding this legal principle reflect that, as a matter of law and independent from any (or lack of) evidence of actual bias, participating both as advocate and as decisionmaker in the same matter poses a constitutionally unacceptable risk of bias.\textsuperscript{48}

\textbf{Argument}

\textbf{I. Commissioner McNamee should recuse himself from the FPA Section 206 Proceeding to determine a replacement rate for PJM’s capacity market in light of his past clients’ significant financial stake in the outcome.}

Clean Energy Advocates respectfully urge Commissioner McNamee to recuse himself from this matter involving former clients. Dominion has forcefully advocated for its position in this proceeding, arguing that state-regulated integrated utilities should not be subject to a revised MOPR in PJM’s capacity market. Duke has requested even more particular exceptions from MOPR to protect the particular financial interests of its affiliates, while Direct Energy, Inc. has similarly advocated rigorously for its interests. Commissioner McNamee is in a position to make these requests a reality. Should the Commission issue an order establishing a replacement rate that, for example, instituted new MOPR rules with exemptions benefitting state-regulated

\footnotesize{pleading); \textit{Lead Industries Ass ‘n. v. EPA}, 647 F.2d 1130, 1176 (D.C. Cir. 1980) (emphasizing that the EPA official had “never appeared in or in any way participated on NRDC’s behalf in the EPA proceedings” to establish a particular pollution standard in upholding a decision not to recuse); \textit{Amos Treat & Co. v. SEC}, 306 F.2d 260, 266–67 (D.C. Cir. 1962).}

\footnotesize{\textit{Am. Gen. Ins. Co. v. F.T.C.}, 589 F.2d 462, 463–65 (9th Cir. 1979).}

\footnotesize{\textit{Id.} at 465 (“mere responsibility for administrative supervision of the Department, regardless of the extent of his knowledge and his approval of the acts of his subordinates, has been deemed sufficient to activate the disqualification rule”); \textit{State ex rel. Ellis v. Kelly}, 145 W. Va. 70, 75–76 (W. Va. 1960) (“It can hardly be contended that the commissioner, in the making of the investigation and in testifying before the deputy commissioner appointed by him and responsible to him, beyond any reasonable probability, did not become biased and prejudiced in the matter being heard.”); \textit{Anderson v. Indus. Comm’n of Utah}, 696 P.2d 1219, 1221 (Utah 1985) (“In other words, when a judge has previously been involved in a case as an attorney, there is no need to show actual prejudice. The law presumes prejudice in such circumstances.”).}

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integrated utilities like Dominion, or carving out state support like the OVEC power purchase agreement to the benefit of Duke, it would cause a reasonable person to question the impartiality of the proceeding. This appearance of potential bias, irrespective of the presence of actual bias, warrants Commissioner McNamee’s recusal in this proceeding.

The OGE regulations make clear that a “covered relationship” (such as an attorney-client relationship) can require recusal even after the relationship has concluded. The regulations give the following illustrative example:

Example 4: An engineer has just resigned from her position as vice president of an electronics company in order to accept employment with the Federal Aviation Administration in a position involving procurement responsibilities. Although the employee did not receive an extraordinary payment in connection with her resignation and has severed all financial ties with the firm, under the circumstances she would be correct in concluding that her former service as an officer of the company would be likely to cause a reasonable person to question her impartiality if she were to participate in the administration of a DOT contract for which the firm is a first-tier subcontractor. 49

According the Commission’s DAEO, in implementing 5 C.F.R. § 2635.502, “FERC presumes that an employee’s impartiality would be questioned if (s)he participated in a prior employer’s matter within a year”; the Commission thus restricts employees from working for their previous employer for at least one year. 50 Similarly, the Ethics Pledge requires executive appointees to refrain from participating in any matter involving a former client for two years from the date of appointment. 51 Thus, in light of both Commission practice and the executive branch-wide Ethics Pledge, Commissioner McNamee’s remunerative attorney-client relationship with Dominion,

49 5 C.F.R. § 2635.502 (emphasis added).
50 Beamon et al., supra note 32 at Slide 12.
51 Executive Order 13770.
Duke, and Direct Energy, Inc. presents a conflict of interest warranting recusal from this proceeding.

The temporal restriction on participation in matters involving prior employers or clients should be understood as extending to all such proceedings that began before or within the Ethics Pledge’s two-year window. Proceedings at the Commission can last for well over two years, and an official ethically restricted from participating in a proceeding should not be able to insert himself or herself into that proceeding once the two-year window elapsed. Permitting such behavior would reduce ethical rules intended to preserve the integrity of government decision-making in the public eye to a mere formality. Broadly construing the Ethics Pledge’s two-year window also provides an additional safeguard against officials influencing matters they may have directly or indirectly participated in during prior employment. Indeed, the FPA Section 206 complaint that initiated the current proceeding was filed on March 21, 2016, and Dominion made numerous filings in that initial docket in subsequent months—a period that coincides with Commissioner McNamee’s representation of Dominion at McGuireWoods LLP. Regardless of whether Commissioner McNamee in fact advised Dominion regarding the initial Section 206 complaint, recusal would have the salutary effect of preventing any appearance of a conflict of interest.

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52 Calpine Corporation et al. v. PJM Interconnection, L.L.C., Protest of Dominion Resources Services, Inc. et al., Docket No. EL16-49-000 (Apr. 11, 2016); Calpine Corporation et al. v. PJM Interconnection, L.L.C., Motion for Leave to Answer and Answer of Dominion Resources Services, Inc. et al., Docket No. EL16-49-000 (Apr. 25, 2016); Calpine Corporation et al. v. PJM Interconnection, L.L.C., Motion to Dismiss of Dominion Resources Services, Inc. et al., Docket No. EL16-49-000 (May 6, 2016).

53 Both Dominion and Direct Energy, Inc. retained law firms other than McGuireWoods LLP for these filings. It remains unclear whether Commissioner McNamee advised either Dominion of Direct Energy, Inc. regarding the initial Section 206 complaint during this period.
With the exception of the instant proceeding, Commissioner McNamee has largely recused himself from matters involving former clients Dominion, Duke, and Direct Energy. To avoid the appearance of bias and preserve the due process rights of the parties, Clean Energy Advocates respectfully request Commissioner McNamee’s recusal in this proceeding as well.

II. Commissioner McNamee must explain the basis for his failure to recuse.

Commissioner McNamee’s prior relationship with Dominion, Duke, and Direct Energy, Inc. as clients of McGuireWoods LLP during the pendency of this proceeding, as well as his regular recusal from other matters in which these parties are substantially engaged, strongly suggest he must recuse himself from this proceeding. At minimum, Commissioner McNamee should explain how his participation in this docket is consistent with due process and ethics rules. Absent an explanation, parties have no record basis for concluding that the Commission is acting as an impartial adjudicator in this proceeding. Transparency and disclosure of the basis for Commissioner McNamee’s decision to participate in this matter is an essential step toward achieving a core objective of due process and federal ethics law: avoiding even the appearance of bias.

Conclusion

For the foregoing reasons, Clean Energy Advocates respectfully request that Commissioner McNamee explain his basis for failing to recuse himself from this proceeding. In the absence of any information in the public record justifying that failure to recuse, Clean Energy Advocates further request his recusal from the proceeding.

54 Supra, note 1.
55 See e.g., Supplemental Standards of Ethical Conduct for Employees of the Federal Energy Regulatory Commission, 61 Fed. Reg. 43,411, 43,412 (omitting a requirement for FERC commissioners to submit separate documentation of their recusals because commissioners “indicate their nonparticipation in public matters on the public record”).
Respectfully submitted,

/s/ Carter Hall
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chall@earthjustice.org

Attorney for Sierra Club

/s/ Thomas Rutigliano
Thomas Rutigliano
Senior Advocate
Natural Resources Defense Council
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Washington DC 20005
trutigliano@nrdc.org

For Natural Resources Defense Council
CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 9th day of September, 2019.

/s/ Mario A. Luna
Mario A. Luna
Litigation Assistant
1625 Massachusetts Avenue, NW, Suite 702
Washington, DC 20036
(202) 667-4500
aluna@earthjustice.org
Exhibit A
Non-Exhaustive List of McNamee Recusals
Non-exhaustive list of Commissioner McNamee’s Recusals

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<thead>
<tr>
<th>Docket Number</th>
<th>Case Caption</th>
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<tbody>
<tr>
<td>EL08-14-012</td>
<td>Black Oak Energy, LLC, EPIC Merchant Energy, LP and SESCO Enterprises, LLC v. PJM Interconnection, L.L.C.</td>
<td>Duke Energy Ohio, Inc. Dominion Resources Services</td>
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<td>Virginia Electric and Power Company v. PJM Interconnection, L.L.C.</td>
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<td>Direct Energy Business, LLC Dominion Resources Services, Inc. Duke Energy Corporation</td>
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<td>Dominion Energy Resources, Inc (complainant in original docket)</td>
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<td>Inquiry Regarding the Commission’s Policy for Recovery of Income Tax Costs</td>
<td>Dominion Energy Resources, Inc</td>
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<td>EL19-8</td>
<td>PJM Interconnection, L.L.C.</td>
<td>Direct Energy Business, LLC Direct Energy Dominion Energy Services, Inc.</td>
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## Non-exhaustive list of Commissioner McNamee’s Recusals

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# Non-exhaustive list of Commissioner McNamee’s Recusals

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Exhibit B

Executive Branch Personnel
Public Financial Disclosure Report (OGE Form 278e)

Filer's Information
McNamee, Bernard L
Commissioner, Federal Energy Regulatory Commission

Other Federal Government Positions Held During the Preceding 12 Months:
Executive Director, Office of Policy, U.S. Dept. of Energy (6/2018 - Present) See endnote

Names of Congressional Committees Considering Nomination:
- Committee on Energy and Natural Resources

Electronic Signature - I certify that the statements I have made in this form are true, complete and correct to the best of my knowledge.
/s/ McNamee, Bernard L [electronically signed on 08/06/2018 by McNamee, Bernard L in Integrity.gov]

Agency Ethics Official's Opinion - On the basis of information contained in this report, I conclude that the filer is in compliance with applicable laws and regulations (subject to any comments below).
/s/ Allen, Kathryn B, Certifying Official [electronically signed on 10/05/2018 by Allen, Kathryn B in Integrity.gov]

Other review conducted by

McNamee, Bernard L - Page 1
U.S. Office of Government Ethics Certification

/s/ Rounds, Emory, Certifying Official [electronically signed on 10/05/2018 by Rounds, Emory in Integrity.gov]
1. Filer’s Positions Held Outside United States Government

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<td>McGuireWoods LLP</td>
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<td>2/2018</td>
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2. Filer’s Employment Assets & Income and Retirement Accounts

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<th>INCOME TYPE</th>
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</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>McGuireWoods LLP (law firm)</td>
<td>N/A</td>
<td>N/A</td>
<td>Salary/Bonus</td>
<td>$164,257</td>
</tr>
<tr>
<td>2</td>
<td>Commonwealth of Virginia, VRS defined benefit plan, (not readily ascertainable value)</td>
<td>See Endnote</td>
<td>N/A</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>State of Texas Employees Retirement System of Texas, defined benefit plan, (not readily ascertainable value)</td>
<td>See Endnote</td>
<td>N/A</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Texas Public Policy Foundation</td>
<td>N/A</td>
<td>N/A</td>
<td>Salary</td>
<td>$47,051</td>
</tr>
<tr>
<td>5</td>
<td>State of Texas Empower Retirement, LifePath Index 2030 Fund F</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>#</td>
<td>DESCRIPTION</td>
<td>EIF</td>
<td>VALUE</td>
<td>INCOME TYPE</td>
<td>INCOME AMOUNT</td>
</tr>
<tr>
<td>----</td>
<td>--------------------------------------</td>
<td>-----</td>
<td>------------------</td>
<td>------------------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>6</td>
<td>T. Rowe Price Blue Chip Growth Fund</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>T. Rowe Price Capital Opportunity Fund</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>McGuireWoods LLP 401(k)</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8.1</td>
<td>T. Rowe Price Retirement 2030 Tr. A</td>
<td>Yes</td>
<td>$500,001 - $1,000,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Hunton &amp; Williams LLP 401(k)</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9.1</td>
<td>Vanguard Institutional Index Plus</td>
<td>Yes</td>
<td>$15,001 - $50,000</td>
<td>$201 - $1,000</td>
<td></td>
</tr>
<tr>
<td>9.2</td>
<td>Dodge &amp; Cox Stock Fund</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>$201 - $1,000</td>
<td></td>
</tr>
<tr>
<td>9.3</td>
<td>Fidelity Diversified International K fund</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>$201 - $1,000</td>
<td></td>
</tr>
<tr>
<td>9.4</td>
<td>Fidelity Puritan K fund</td>
<td>Yes</td>
<td>$15,001 - $50,000</td>
<td>$201 - $1,000</td>
<td></td>
</tr>
</tbody>
</table>

3. Filer's Employment Agreements and Arrangements

<table>
<thead>
<tr>
<th>#</th>
<th>EMPLOYER OR PARTY</th>
<th>CITY, STATE</th>
<th>STATUS AND TERMS</th>
<th>DATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>McGuireWoods LLP</td>
<td>Richmond, Virginia</td>
<td>I will continue to hold the 401 (k) account. The employer did not and will not make contributions.</td>
<td>2/2006</td>
</tr>
<tr>
<td>2</td>
<td>Hunton &amp; Williams LLP</td>
<td>Richmond, Virginia</td>
<td>I will continue to hold the 401(k) account. The employer did not and will not make contributions.</td>
<td>2/1998</td>
</tr>
<tr>
<td>3</td>
<td>State of Texas</td>
<td>Austin, Texas</td>
<td>I will continue to hold this defined contribution plan, but the plan sponsor no longer makes contributions.</td>
<td>11/2014</td>
</tr>
<tr>
<td>4</td>
<td>Commonwealth of Virginia</td>
<td>Richmond, Virginia</td>
<td>I will continue to participate in this defined benefit plan.</td>
<td>2/1995</td>
</tr>
<tr>
<td>#</td>
<td>EMPLOYER OR PARTY</td>
<td>CITY, STATE</td>
<td>STATUS AND TERMS</td>
<td>DATE</td>
</tr>
<tr>
<td>----</td>
<td>-------------------------------------------------------</td>
<td>----------------</td>
<td>----------------------------------------------------------------------------------</td>
<td>----------</td>
</tr>
<tr>
<td>5</td>
<td>State of Texas Employees RetirementSystem of Texas</td>
<td>Austin, Texas</td>
<td>I will continue to participate in this defined benefit plan.</td>
<td>11/2014</td>
</tr>
<tr>
<td>6</td>
<td>Texas Public Policy Foundation</td>
<td>Austin, Texas</td>
<td>I will continue to hold the 401(b) account. The employer did not and will not make contributions.</td>
<td>2/2018</td>
</tr>
</tbody>
</table>

4. Filer's Sources of Compensation Exceeding $5,000 in a Year

<table>
<thead>
<tr>
<th>#</th>
<th>SOURCE NAME</th>
<th>CITY, STATE</th>
<th>BRIEF DESCRIPTION OF DUTIES</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Texas Public Policy Foundation</td>
<td>Austin, Texas</td>
<td>Director of Life: Powered and Director of the Center for Tenth Amendment Action</td>
</tr>
<tr>
<td>2</td>
<td>McGuireWoods LLP</td>
<td>Richmond, Virginia</td>
<td>Provided representation and advice to law firm's clients.</td>
</tr>
<tr>
<td>3</td>
<td>Dominion Energy Services Inc.</td>
<td>Richmond, Virginia</td>
<td>Legal services to Dominion Energy Services’ affiliates Virginia Electric and Power Company d/b/a Dominion Virginia Power and Dominion North Carolina Power (clients of McGuireWoods LLP)</td>
</tr>
<tr>
<td>4</td>
<td>Direct Energy, Inc.</td>
<td>Richmond, Virginia</td>
<td>Legal services (client of McGuireWoods LLP)</td>
</tr>
<tr>
<td>5</td>
<td>NOVI Energy</td>
<td>Richmond, Virginia</td>
<td>Legal services to subsidiary City Point Energy Center LLC (client of McGuireWoods LLP)</td>
</tr>
</tbody>
</table>

5. Spouse's Employment Assets & Income and Retirement Accounts

<table>
<thead>
<tr>
<th>#</th>
<th>DESCRIPTION</th>
<th>EIF</th>
<th>VALUE</th>
<th>INCOME TYPE</th>
<th>INCOME AMOUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hunton &amp; Williams LLP 401(k)</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.1</td>
<td>Fidelity NB Genesis R6</td>
<td>Yes</td>
<td>$50,001 - $100,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
</tbody>
</table>

McNamee, Bernard L - Page 5
6. Other Assets and Income

<table>
<thead>
<tr>
<th>#</th>
<th>DESCRIPTION</th>
<th>EIF</th>
<th>VALUE</th>
<th>INCOME TYPE</th>
<th>INCOME AMOUNT</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Virginia 529 Chesapeake Plan/Age Based Portfolio 2021</td>
<td>See Endnote</td>
<td>Yes</td>
<td>$15,001 - $50,000</td>
<td>None (or less than $201)</td>
</tr>
<tr>
<td>2</td>
<td>Virginia Pre Paid Tuition</td>
<td>See Endnote</td>
<td>N/A</td>
<td>$15,001 - $50,000</td>
<td>None (or less than $201)</td>
</tr>
<tr>
<td>3</td>
<td>T. Rowe Price Spectrum Growth Fund</td>
<td>Yes</td>
<td>$15,001 - $50,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Vanguard 500 Index Admiral Shares</td>
<td>Yes</td>
<td>$100,001 - $250,000</td>
<td>$5,001 - $15,000</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>U.S. bank #1 money market account/checking (cash)</td>
<td>N/A</td>
<td>$100,001 - $250,000</td>
<td>Interest</td>
<td>$201 - $1,000</td>
</tr>
<tr>
<td>6</td>
<td>U.S. bank #1 savings account (cash)</td>
<td>N/A</td>
<td>$100,001 - $250,000</td>
<td>Interest</td>
<td>$201 - $1,000</td>
</tr>
<tr>
<td>7</td>
<td>U.S. credit union #1 savings account (cash)</td>
<td>N/A</td>
<td>$1,001 - $15,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Local Finance Solutions stock (investment and accounting services)</td>
<td>N/A</td>
<td>$1,001 - $15,000</td>
<td>Dividends</td>
<td>$1,001 - $2,500</td>
</tr>
<tr>
<td>9</td>
<td>Fidelity Growth Strategies Fund</td>
<td>Yes</td>
<td>$1,001 - $15,000</td>
<td>None (or less than $201)</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>U.S. bank #2 checking account (cash)</td>
<td>N/A</td>
<td>$1,001 - $15,000</td>
<td>Interest</td>
<td>None (or less than $201)</td>
</tr>
<tr>
<td>11</td>
<td>BSM Trust</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11.1</td>
<td>Sterling Capital Equity Fund</td>
<td>Yes</td>
<td>$50,001 - $100,000</td>
<td></td>
<td>$2,501 - $5,000</td>
</tr>
<tr>
<td>11.2</td>
<td>Vanguard Index 500</td>
<td>Yes</td>
<td>$100,001 - $250,000</td>
<td></td>
<td>$2,501 - $5,000</td>
</tr>
</tbody>
</table>
7. Transactions

(N/A) - Not required for this type of report

8. Liabilities

<table>
<thead>
<tr>
<th>#</th>
<th>CREDITOR NAME</th>
<th>TYPE</th>
<th>AMOUNT</th>
<th>YEAR INCURRED</th>
<th>RATE</th>
<th>TERM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Well Fargo Home Mortgage</td>
<td>Mortgage on Personal Residence</td>
<td>$15,001 - $50,000</td>
<td>2015</td>
<td>3.25%</td>
<td>15 years</td>
</tr>
</tbody>
</table>

9. Gifts and Travel Reimbursements

(N/A) - Not required for this type of report
Endnotes

<table>
<thead>
<tr>
<th>PART</th>
<th>#</th>
<th>ENDNOTE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Filer's Information</td>
<td>2</td>
<td>This position started as an acting position. I had been rehired as Deputy General Counsel for Energy Policy and then detailed to be Executive Director, Office of Policy.</td>
</tr>
<tr>
<td>2.</td>
<td>2</td>
<td>Total annuity value not readily ascertainable, present cash value is between $50,000 and $100,000.</td>
</tr>
<tr>
<td>2.</td>
<td>3</td>
<td>Total annuity value not readily ascertainable, present cash value is between $1,001 and $15,000.</td>
</tr>
<tr>
<td>5.</td>
<td>2</td>
<td>My wife is a writer and self-published a book July 2018.</td>
</tr>
<tr>
<td>6.</td>
<td>1</td>
<td>Held for benefit of dependent child.</td>
</tr>
<tr>
<td>6.</td>
<td>2</td>
<td>Held for the benefit of dependent child.</td>
</tr>
</tbody>
</table>
Summary of Contents

1. Filer’s Positions Held Outside United States Government

Part 1 discloses positions that the filer held at any time during the reporting period (excluding positions with the United States Government). Positions are reportable even if the filer did not receive compensation.

This section does not include the following: (1) positions with religious, social, fraternal, or political organizations; (2) positions solely of an honorary nature; (3) positions held as part of the filer's official duties with the United States Government; (4) mere membership in an organization; and (5) passive investment interests as a limited partner or non-managing member of a limited liability company.

2. Filer’s Employment Assets & Income and Retirement Accounts

Part 2 discloses the following:

- Sources of earned and other non-investment income of the filer totaling more than $200 during the reporting period (e.g., salary, fees, partnership share, honoraria, scholarships, and prizes)
- Assets related to the filer’s business, employment, or other income-generating activities that (1) ended the reporting period with a value greater than $1,000 or (2) produced more than $200 in income during the reporting period (e.g., equity in business or partnership, stock options, retirement plans/accounts and their underlying holdings as appropriate, deferred compensation, and intellectual property, such as book deals and patents)

This section does not include assets or income from United States Government employment or assets that were acquired separately from the filer’s business, employment, or other income-generating activities (e.g., assets purchased through a brokerage account). Note: The type of income is not required if the amount of income is $0 - $200 or if the asset qualifies as an excepted investment fund (EIF).

3. Filer’s Employment Agreements and Arrangements

Part 3 discloses agreements or arrangements that the filer had during the reporting period with an employer or former employer (except the United States Government), such as the following:

- Future employment
- Leave of absence
- Continuing payments from an employer, including severance and payments not yet received for previous work (excluding ordinary salary from a current employer)
- Continuing participation in an employee welfare, retirement, or other benefit plan, such as pensions or a deferred compensation plan
- Retention or disposition of employer-awarded equity, sharing in profits or carried interests (e.g., vested and unvested stock options, restricted stock, future share of a company’s profits, etc.)
4. Filer’s Sources of Compensation Exceeding $5,000 in a Year

Part 4 discloses sources (except the United States Government) that paid more than $5,000 in a calendar year for the filer’s services during any year of the reporting period.

The filer discloses payments both from employers and from any clients to whom the filer personally provided services. The filer discloses a source even if the source made its payment to the filer’s employer and not to the filer. The filer does not disclose a client’s payment to the filer’s employer if the filer did not provide the services for which the client is paying.

5. Spouse’s Employment Assets & Income and Retirement Accounts

Part 5 discloses the following:

- Sources of earned income (excluding honoraria) for the filer’s spouse totaling more than $1,000 during the reporting period (e.g., salary, consulting fees, and partnership share)
- Sources of honoraria for the filer’s spouse greater than $200 during the reporting period
- Assets related to the filer’s spouse’s employment, business activities, other income-generating activities that (1) ended the reporting period with a value greater than $1,000 or (2) produced more than $200 in income during the reporting period (e.g., equity in business or partnership, stock options, retirement plans/accounts and their underlying holdings as appropriate, deferred compensation, and intellectual property, such as book deals and patents)

This section does not include assets or income from United States Government employment or assets that were acquired separately from the filer’s spouse’s business, employment, or other income-generating activities (e.g., assets purchased through a brokerage account). Note: The type of income is not required if the amount of income is $0 - $200 or if the asset qualifies as an excepted investment fund (EIF). Amounts of income are not required for a spouse’s earned income (excluding honoraria).

6. Other Assets and Income

Part 6 discloses each asset, not already reported, that (1) ended the reporting period with a value greater than $1,000 or (2) produced more than $200 in investment income during the reporting period. For purposes of the value and income thresholds, the filer aggregates the filer’s interests with those of the filer’s spouse and dependent children.

This section does not include the following types of assets: (1) a personal residence (unless it was rented out during the reporting period); (2) income or retirement benefits associated with United States Government employment (e.g., Thrift Savings Plan); and (3) cash accounts (e.g., checking, savings, money market accounts) at a single financial institution with a value of $5,000 or less (unless more than $200 of income was produced). Additional exceptions apply. Note: The type of income is not required if the amount of income is $0 - $200 or if the asset qualifies as an excepted investment fund (EIF).

7. Transactions
Part 7 discloses purchases, sales, or exchanges of real property or securities in excess of $1,000 made on behalf of the filer, the filer's spouse or dependent child during the reporting period.

This section does not include transactions that concern the following: (1) a personal residence, unless rented out; (2) cash accounts (e.g., checking, savings, CDs, money market accounts) and money market mutual funds; (3) Treasury bills, bonds, and notes; and (4) holdings within a federal Thrift Savings Plan account. Additional exceptions apply.

8. Liabilities

Part 8 discloses liabilities over $10,000 that the filer, the filer's spouse or dependent child owed at any time during the reporting period.

This section does not include the following types of liabilities: (1) mortgages on a personal residence, unless rented out (limitations apply for PAS filers); (2) loans secured by a personal motor vehicle, household furniture, or appliances, unless the loan exceeds the item's purchase price; and (3) revolving charge accounts, such as credit card balances, if the outstanding liability did not exceed $10,000 at the end of the reporting period. Additional exceptions apply.

9. Gifts and Travel Reimbursements

This section discloses:

- Gifts totaling more than $390 that the filer, the filer's spouse, and dependent children received from any one source during the reporting period.
- Travel reimbursements totaling more than $390 that the filer, the filer's spouse, and dependent children received from any one source during the reporting period.

For purposes of this section, the filer need not aggregate any gift or travel reimbursement with a value of $156 or less. Regardless of the value, this section does not include the following items: (1) anything received from relatives; (2) anything received from the United States Government or from the District of Columbia, state, or local governments; (3) bequests and other forms of inheritance; (4) gifts and travel reimbursements given to the filer's agency in connection with the filer's official travel; (5) gifts of hospitality (food, lodging, entertainment) at the donor's residence or personal premises; and (6) anything received by the filer's spouse or dependent children totally independent of their relationship to the filer. Additional exceptions apply.
Privacy Act Statement

Title I of the Ethics in Government Act of 1978, as amended (the Act), 5 U.S.C. app. § 101 et seq., as amended by the Stop Trading on Congressional Knowledge Act of 2012 (Pub. L. 112-105) (STOCK Act), and 5 C.F.R. Part 2634 of the U. S. Office of Government Ethics regulations require the reporting of this information. The primary use of the information on this report is for review by Government officials to determine compliance with applicable Federal laws and regulations. This report may also be disclosed upon request to any requesting person in accordance with sections 105 and 402(b)(1) of the Act or as otherwise authorized by law. You may inspect applications for public access of your own form upon request. Additional disclosures of the information on this report may be made: (1) to any requesting person, subject to the limitation contained in section 208(d)(1) of title 18, any determination granting an exemption pursuant to sections 208(b)(1) and 208(b)(3) of title 18; (2) to a Federal, State, or local law enforcement agency if the disclosing agency becomes aware of violations or potential violations of law or regulation; (3) to another Federal agency, court or party in a court or Federal administrative proceeding when the Government is a party or in order to comply with a judge-issued subpoena; (4) to a source when necessary to obtain information relevant to a conflict of interest investigation or determination; (5) to the National Archives and Records Administration or the General Services Administration in records management inspections; (6) to the Office of Management and Budget during legislative coordination on private relief legislation; (7) to the Department of Justice or in certain legal proceedings when the disclosing agency, an employee of the disclosing agency, or the United States is a party to litigation or has an interest in the litigation and the use of such records is deemed relevant and necessary to the litigation; (8) to reviewing officials in a new office, department or agency when an employee transfers or is detailed from one covered position to another; (9) to a Member of Congress or a congressional office in response to an inquiry made on behalf of an individual who is the subject of the record; (10) to contractors and other non-Government employees working on a contract, service or assignment for the Federal Government when necessary to accomplish a function related to an OGE Government-wide system of records; and (11) on the OGE Website and to any person, department or agency, any written ethics agreement filed with OGE by an individual nominated by the President to a position requiring Senate confirmation. See also the OGE/GOV-1 executive branch-wide Privacy Act system of records.

Public Burden Information

This collection of information is estimated to take an average of three hours per response, including time for reviewing the instructions, gathering the data needed, and completing the form. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Program Counsel, U.S. Office of Government Ethics (OGE), Suite 500, 1201 New York Avenue, NW., Washington, DC 20005-3917.

Pursuant to the Paperwork Reduction Act, as amended, an agency may not conduct or sponsor, and no person is required to respond to, a collection of information unless it displays a currently valid OMB control number (that number, 3209-0001, is displayed here and at the top of the first page of this OGE Form 278e).
Exhibit C
Letter from Bernard L. McNamee to DAEO Charles A. Beamon
(Oct. 5, 2018)
Charles A. Beamon  
Designated Agency Ethics Official  
Federal Energy Regulatory Commission  
888 First St., NE  
Washington, D.C. 20426

Dear Mr. Beamon:

The purpose of this letter is to describe the steps that I will take to avoid any actual or apparent conflict of interest in the event that I am confirmed for the position of Commissioner, Federal Energy Regulatory Commission.

As required by 18 U.S.C. § 208(a), I will not participate personally and substantially in any particular matter in which I know that I have a financial interest directly and predictably affected by the matter, or in which I know that a person whose interests are imputed to me has a financial interest directly and predictably affected by the matter, unless I first obtain a written waiver, pursuant to 18 U.S.C. § 208(b)(1), or qualify for a regulatory exemption, pursuant to 18 U.S.C. § 208(b)(2). I understand that the interests of the following persons are imputed to me: any spouse or minor child of mine; any general partner of a partnership in which I am a limited or general partner; any organization in which I serve as officer, director, trustee, general partner or employee; and any person or organization with which I am negotiating or have an arrangement concerning prospective employment.

I recently resigned from my position with the Texas Public Policy Foundation. For a period of one year after my resignation, I will not participate personally and substantially in any particular matter involving specific parties in which I know the Texas Public Policy Foundation is a party or represents a party, unless I am first authorized to participate, pursuant to 5 C.F.R. § 2635.502(d).

I will retain my position as a trustee of the BSM Family Trust. I will not receive any fees for the services that I provide as a trustee during my appointment to the position of Commissioner, Federal Energy Regulatory Commission. I will not participate personally and substantially in any particular matter that to my knowledge has a direct and predictable effect on the financial interests of the BSM Family Trust or its underlying assets, unless I first obtain a written waiver, pursuant to 18 U.S.C. § 208(b)(1), or qualify for a regulatory exemption, pursuant to 18 U.S.C. § 208(b)(2).
If I have a managed account or otherwise use the services of an investment professional during my appointment, I will ensure that the account manager or investment professional obtains my prior approval on a case-by-case basis for the purchase of any assets other than cash, cash equivalents, investment funds that qualify for the exemption at 5 C.F.R. § 2640.201(a), or obligations of the United States.

I understand that as an appointee I will be required to sign the Ethics Pledge (Exec. Order No. 13770) and that I will be bound by the requirements and restrictions therein in addition to the commitments I have made in this ethics agreement. I also understand that I am subject to the standards of ethical conduct for employees of the Executive Branch.

I will meet in person with you during the first week of my service in the position of Commissioner in order to complete the initial ethics briefing required under 5 C.F.R. § 2638.305. Within 90 days of my confirmation, I will document my compliance with this ethics agreement by notifying you in writing when I have completed the steps described in this ethics agreement.

Finally, I have been advised that this ethics agreement will be posted publicly, consistent with 5 U.S.C. § 552, on the website of the U.S. Office of Government Ethics along with ethics agreements of other Presidential nominees who file public financial disclosure reports.

Sincerely,

[Signature]

Bernard L. McNamee

10-5-18