UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-___-000
	)	
PJM Interconnection, L.L.C.	)	

COMPLAINT AND REQUEST FOR CLARIFICATION
REQUESTING FAST TRACK PROCESSING

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PJM Power Providers Group ("P3") hereby files this complaint seeking critical revisions to the fatally flawed buyer-market-power mitigation provisions in PJM's Open Access Transmission Tariff.[1] The Commission repeatedly has affirmed the need to fully mitigate buyer market power, just as it repeatedly has fully mitigated seller market power. When it approved the PJM capacity market—known as RPM—the Commission obviously thought it was imposing an effective buyer-side mitigation regime. It now is apparent, however, that there are fatal—and unjust, unreasonable, and unduly discriminatory—flaws in the governing tariff scheme. We propose to repair these flaws with tariff changes largely tracking the Commission's recent order improving NYISO's buyer mitigation regime. In support, we offer the attached, at P3 Exhibit 1, testimony of Dr. Roy Shanker. We expect PJM to make a section 205 filing proposing similar mitigation measures in the very near future—a case that should be consolidated with this one.

By promptly granting our complaint, the Commission will maintain the efficacy of competitive capacity markets—markets the Commission itself created in order to benefit consumers by ensuring resource adequacy at the lowest possible cost. This will help provide all

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1 P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM region. Combined, P3's twelve member companies own over 80,000 megawatts of power and over 51,000 miles of transmission lines in the PJM region, serve nearly 12.2 million customers and employ over 55,000 people in the 13-state and District of Columbia PJM region. The content of this complaint represents the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, please visit www.p3powergroup.com.

stakeholders with just, reasonable and non-discriminatory rates. In particular, prompt Commission action will create lower costs for consumers over the long term. It also will encourage effective load management programs. In fact, without meaningful relief, demand response resources face severe revenue losses, possibly forcing them to exit the market—elbowed aside by uneconomic and unneeded generating resources installed to exercise buyer market power.

We seek fast-track treatment in order to have the most critical revisions in place by mid-April 2011, *before* the next RPM auction is held. Other changes are, we submit, ultimately required in order to have a just, reasonable and non-discriminatory buyer mitigation regime. But we propose a "phasing" approach in order to facilitate prompt action on the items that are most important to ensure just, reasonable and non-discriminatory outcomes in the May 2011 auction. In the next section of this pleading, we explain the precise breakdown of issues needing immediate action versus those that can be deferred. In a nutshell, the Commission should revise the core mechanics of the mitigation regime: (1) how to screen for uncompetitive offers (the correct measure is 100% of the benchmark), (2) whether to have an impact screen (there should *not* be one), (3) how to re-price uncompetitive offers (100% of the benchmark is, again, the right answer), and (4) the duration of mitigation (mitigation should last, as in NYISO, until a resource demonstrates that it is competitive by clearing two auctions at competitive offer levels). All of these flaws in the existing mitigation regime need to be fixed at the same time, because a failure to resolve any one of them will render the entire scheme ineffective. When it comes to the core mechanics of buyer mitigation, the scheme as a whole is only as strong as its weakest link.

Ultimately this revised regime should apply to all capacity resources; anything less is unjust, unreasonable and unduly discriminatory. But for the next auction, we propose to apply the revised mitigation regime only to combustion turbines and combined cycle resources. This phasing approach will leave certain more contentious issues, such as mitigation of renewable and demand response resources, for subsequent consideration. These deferred issues are critical to the long-term viability of the capacity market, but the Commission need not give them any substantive attention at this point in time. The Commission should, instead, order PJM to make a compliance filing addressing these issues, after a stakeholder process, on a time frame designed to ensure that additional tariff changes are put into effect before the May 2012 auction.

SUMMARY

Prompt action is critical because the State of New Jersey has just enacted legislation designed to procure, in a discriminatory manner, up to 2,000 MW of new generation that must be offered into PJM's capacity market at prices low enough to guarantee clearing. *See* S. No. 2381, 214th Leg. (N.J. 2011) ("New Jersey Law"), attached as P3 Exhibit 2. This potential new entry is not supported by market economics. As we explain in detail below, there is a surplus of generation in PJM. In addition, PJM's new energy forecasts show that demand for electricity has decreased substantially. Strikingly, PJM now predicts that New Jersey will not reach the demand previously forecasted for 2014 until at least 2020. PJM, Load Forecast Report at tbl.B-1 (Jan. 2010), http://www.pjm.com/~/media/documents/reports/2010-load-forecast-report.ashx. The New Jersey Law is not need-based, because there is no need. Instead, the goal of the legislation is to artificially suppress capacity clearing prices for many years into the future. The total financial impact of adding 2,000 MW of unneeded, uneconomic generation is profound—totaling *$2 billion in the first year alone*, with artificial price suppression continuing until the uneconomic capacity has been fully absorbed (by load growth and the premature retirement of otherwise economic resources). And there currently is nothing to prevent the recurrence of similar conduct again and again.

The Commission would never stand aside if alerted to alleged supplier conduct that could, without prompt corrective action, artificially inflate clearing prices by many billions of dollars. And it should not stand aside here. It should, instead, immediately grant fast-track treatment, and then grant the relief we seek—in time for the revised mitigation scheme to be in place for the May 2011 auction.

While the New Jersey Law is the triggering event driving expedited action here, unfortunately it is not unique. Buyer market power has proven to be a recurring and pervasive phenomenon in organized capacity markets. Maryland has, in fact, already announced a process that looks very much like New Jersey's exercise of buyer market power. *See In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010) ("Maryland RFP"), attached as P3 Exhibit 3 (without attachments). Much as with New Jersey, the PJM market monitor has estimated that if 1,800 MW of subsidized uneconomic entry were to respond to this proposal, auction price outcomes would be artificially suppressed by more than $1 billion in the first year alone.

According to the market monitor, the New Jersey and Maryland schemes in tandem have the potential to dramatically suppress clearing prices in PJM:

> The Market Monitor's analysis indicates that adding 1,800 MW of installed capacity in the Pepco zone in Maryland, paying it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 92 million dollars in Pepco. If the New Jersey legislation is approved and the proposed RFP is implemented, *the joint result would be a reduction in capacity market revenues to PJM suppliers of more than three billion dollars per year*. …
>
> This substantial reduction in revenue would affect the investment decisions of current owners of capacity and potential investors in capacity both in and outside of Maryland. The likely result is less investment in capacity. Depressing the price in Maryland would also mean that the required direct subsidy by Maryland

> ratepayers would increase with perhaps significant unintended consequences for the business and residential customers who would have to pay the subsidy.

In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv., No. 9214, Comments of the Independent Market Monitor for PJM at 4 (M.P.S.C. Jan. 28, 2011) ("Market Monitor Maryland Report") (emphasis added), http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf. In total, clearing prices under this scenario would be artificially suppressed by between approximately 35 and 40%. *Id.* at 13, 14.

As in New Jersey and Maryland, in most, if not all, instances, state governments and regulators are the driving force behind the exercise of buyer market power. The goal of these efforts is to drive costs lower in the short run. But the results are hardly benign. As the Commission has recognized, if prices are suppressed below competitive levels, society as a whole is worse off. *See, e.g.*, *Amaranth Advisors*, 120 FERC ¶ 61,085 (2007) ("*Amaranth*"); *Energy Transfer Partners*, 120 FERC ¶ 61,086 (2007) ("*ETP*").[2] The suppression of capacity auction prices creates inefficiencies that harm the public interest in general, the market, and consumers in particular. *See generally* Shanker at 16:3–18:15. If prices are suppressed below what would occur in a workably competitive market, society will have the wrong level of investment, coupled with the wrong retirement and consumption decisions. Investment decisions

[2] "The direction in which the manipulative conduct moves the price is immaterial to its legality." *ETP*, 120 FERC ¶ 61,086 at P 31. The Commission's rationale is equally applicable in market design as in enforcement cases: uncompetitive prices, high or low, ultimately hurt markets *and consumers*. *See id.* ("The academic literature takes a similar view; making no distinction between the harms resulting from upward or downward manipulations. These harms may include: *deadweight losses due to distortions in consumption, production*, storage, and transportation, as well as a reduction in hedging effectiveness, and a decline in market liquidity.") (emphasis added); *Amaranth*, 120 FERC ¶ 61,085 at P 123 ("The harm to consumers from an upward manipulation is immediate. Harm from downward manipulation is more long term. … Policing market behavior is about protecting the interest of *all participants, sellers and consumers alike*.") (emphasis added). And the harm to society is the same irrespective of whether the price distortion is due to the exercise of market power or to market manipulation.

that would have been made at price outcomes produced by a workably competitive market will not, in fact, be made. *See id.* at 19:1-9.

In the long run, without effective mitigation, the exercise of buyer market power will sound the death knell of competitive markets—and with them the cost savings that markets create for consumers. *See id.* at 19:15-18. Competitive new entry—which is required to efficiently replace retiring plants and satisfy long-term load growth—can occur only if revenues from all of the bulk power markets are compensatory on an all-in basis. And capacity markets make an important contribution to the overall revenue stream needed to support new entry by compensating, among other things, for the effect of price caps in the day-ahead and real-time energy markets.

As the Commission repeatedly has observed, however, market participants will not commit capital to build new plants unless they believe that capacity markets will be allowed to operate as designed, and, over time, *average* the actual net cost of new entry. And this, of course, necessarily means that sometimes capacity prices will need to be *above* the net cost of new entry (when capacity is short) and sometimes *below* that level (when capacity is long).

If the Commission were to allow the unmitigated exercise of buyer market power, it would completely contradict the fundamental design and purpose of capacity markets. Buyer market power would produce a surplus of capacity resources by building unneeded capacity on an uneconomic basis. And that, in turn, would keep capacity prices permanently *below* the cost of new entry. All existing suppliers would be paid this artificially suppressed price, while a favored subset of suppliers would be paid higher prices on an uneconomic and unduly discriminatory basis.

The unmitigated exercise of buyer market power thus would start a vicious cycle that would eliminate competitive entry, ultimately destroying power markets—and the benefits they create for consumers. If auction clearing prices were to be artificially suppressed below the cost of new entry, then, by definition, the only way that new entry would occur is if it were supported by subsidies from consumers. Competitive suppliers would be unable to enter because prices would never reach competitive levels. And even subsidized entry would occur at elevated prices, because each new entrant would need to charge a risk premium—a deadweight loss to society—reflecting the fact that, once its subsidy ended it no longer would be a favored new entrant, and thus would be paid artificially suppressed prices along with all other existing suppliers. Efficient load management programs would disappear. Ratepayers would have to take the full ownership risk of new resources (including the risk of technology becoming outmoded). States that would have preferred to reap the long-term cost savings that markets bring would, instead, see their costs inflated above competitive levels by states that have chosen to exercise buyer market power. And the ongoing artificial suppression of capacity prices would effectively expropriate the investments of existing suppliers. *See* Shanker at 16:3-16, 18:11–19:18.

Given appropriate intent, and assuming a valid factual basis, buyer-side price suppression could constitute market manipulation under section 222 of the Federal Power Act, 16 U.S.C. § 824v. Certainly that was the analysis set forth in the *Amaranth* and *ETP* Show Cause Orders. There the allegations were that someone sold a commodity at an uneconomically low price, with the intent of reducing the prevailing price in a way that created countervailing profits in related transactions. Here we have load interests contracting for the construction of new capacity when there already is a surplus of existing supply, and then offering that capacity into the market at prices well below its actual cost, for the express purpose of reducing the price paid for all other capacity supplies. We are not asking the Commission to determine whether this constitutes market manipulation. Instead we offer the obvious point that the market design should not create incentives for such conduct. The harm to the market is the same whether load interests are exercising buyer market power or actually engaging in market manipulation. And in either event, the price outcomes are unjust, unreasonable and unduly discriminatory—hence this complaint.[3]

We expect the primary opposing arguments to be that fully mitigating the exercise of buyer market power will (1) increase costs (at least in the short run), (2) interfere with state resource planning decisions, and (3) prevent states from contracting for new entry to ensure reliability. None of these arguments holds water.

First, paying capacity prices that, on average and over time, equilibrate around the actual net cost of new entry, is, at bottom, a bedrock cost (along with transmission) of the bulk power system. Similar costs would be expected in a vertically integrated context, without the efficiencies that markets bring. To see this, we need look no further than American Electric Power Service Corporation's "cost-based" capacity tariff filing, which the Commission recently rejected. *Am. Elec. Power Serv. Corp.*, 134 FERC ¶ 61,039 (2011). There American Electric Power proposed a "cost-based" capacity rate of $388/MW-day—well above RPM clearing prices, which have ranged from $247.12/MW-day (in the PEPCO Locational Deliverability Area) to $27.73/MW-day (in the unconstrained part of PJM).

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[3] This Complaint seeks to fix flaws in the buyer-side market power mitigation provisions in PJM's Tariff. It does not address any issues concerning the legality of the New Jersey statute or any other state statute, issues that are beyond the scope of this Complaint. The Complaint likewise does not address any harm the New Jersey statute may cause to competitive power markets, other than the harm to the capacity market discussed herein.

Additionally, because the New Jersey Law requires generators selected by the state to "participate in and clear the annual base residual auction conducted by PJM" in violation of the Minimum Offer Price Rule, this complaint constitutes an administrative challenge within the meaning of section 4 of the Bill. New Jersey Law at 20.

The exercise of buyer market power gives the illusion of cost savings because the core strategy is to pay a price that reflects the cost of new entry only to new entrants, while paying existing suppliers much less. But as the Commission repeatedly has held, that would violate the Federal Power Act's prohibition against unduly discriminatory rates. It also would produce rates that are well below just and reasonable levels. And it is not how competitive markets work; in competitive markets all suppliers of fungible products receive the same price (a fundamental principle of economics called the "Law of One Price"). This produces the lowest prices, over the long term, for consumers. *See* Shanker at 16:17–17:6; Market Monitor Maryland Report at 4.

Second, effective wholesale buyer market power mitigation does not interfere with choices that states traditionally have been free to make about resource planning, including a choice to favor specific resource types. Within the limits posed by applicable Constitutional limitations, and the Commission's exclusive wholesale jurisdiction, states remain free to exercise their authority over generation facilities, determining whether or where to site generation of various types. They also remain free to sponsor new entry by generation facilities, even if uneconomic by any rational measure. Effective mitigation does not preclude state-sponsored entry.

All effective mitigation does is protect organized capacity markets from harm caused by any entity artificially suppressing wholesale price outcomes. Legitimate state-sponsored entry can occur, but its offers into the capacity market will be mitigated and, once mitigated, might not clear the auction. The Commission has exclusive jurisdiction over capacity markets, and taking steps to ensure that capacity prices are just, reasonable and non-discriminatory—thus producing lower costs for consumers in the long run—is at the core of its statutory mandate. *N.Y. Indep. System Operator*, 122 FERC ¶ 61,211 at P 111, *order on reh'g*, 124 FERC ¶ 61,301 (2008), *order on reh'g and clarification*, 131 FERC ¶ 61,170 (2010). Conversely, declining to impose effective mitigation essentially would turn wholesale price-setting over to the states, contradicting the Federal Power Act and controlling court and agency precedent.

Underscoring the flexibility states have in resource planning, the PJM market design includes a Fixed Resource Requirement ("FRR") option, which allows a state or region to decide to fully plan for all of its resource requirements. As a result, if a state truly thinks that the PJM capacity market is not meeting its needs, it can steer its own course through the FRR option. The one path it *cannot* take is (1) to selectively procure uneconomic resources to meet some of its needs, (2) to buy the rest of its capacity needs through the RPM auctions, and (3) to arrange for the subsidized resources to offer into the auctions on terms that artificially suppress price outcomes. Effective buyer-side mitigation firmly blocks that course of action—just as it should.

Finally, there is no basis for any claim that uneconomic entry is needed to maintain reliability—a contention made in the New Jersey Law. It is odd to see New Jersey make such a claim, given the case the New Jersey Board of Public Utilities and the Maryland Public Service Commission just finished briefing and arguing in the Court of Appeals for the D.C. Circuit, seeking to reset earlier RPM auction outcomes. As Dr. Shanker explains in his testimony, Shanker at 37:10-16, one argument these parties made to the Commission in the underlying proceeding was that PJM's reliability standards are too strict, overstating the need for new entry. *See Md. Pub. Serv. Comm'n v. PJM Interconnection*, 124 FERC ¶ 61,276 at P 12 (2008), *reh'g denied*, 127 FERC ¶ 61,274, *appeal docketed sub nom. Md. Pub. Serv. Comm'n v. FERC*, D.C. Cir. No. 09-1296 (filed Aug. 14, 2009) (oral argument held Nov. 15, 2010). This contention always was misguided. Nonetheless, as the Commission has observed, RPM has been quite successful in attracting resources of many types, from demand response, to imports, to deferred retirements, to new capacity additions, and so forth. *See id.*, 127 FERC ¶ 61,274 at P 23 & n.25. There is no looming reliability crisis. To the contrary, as noted above, PJM's most recent load forecast confirms that demand will only increase modestly over the next decade. PJM, Draft Load Forecast Report at tbl.B-c2 (Dec. 28, 2010), http://www.pjm.com/~/media/committees-groups/subcommittees/las/20110104/20110104-draft-load-report.ashx.

While we have not seen PJM's capacity market attract material new green-field generation development, this reflects the simple and undeniable fact that auction clearing prices have not been high enough to support new green-field entry. We would expect new green-field entry only when prices are *at or above* the nominal levelized actual net cost of new entry, and are expected to average that level over the long term. But in constrained regions in PJM, prices have more often been below the actual net cost of new entry, and the pendency of some large transmission projects in the Eastern Mid-Atlantic Area Council ("EMAAC") region indicates that prices within that zone may drop in the future. *See* Shanker at 36:5-10. In addition, as noted above, according to PJM's most recent load forecast, demand levels formerly expected in New Jersey by 2014 now are not projected to materialize until at least 2020. And now that the New Jersey Law has highlighted the clear loopholes in PJM's buyer market power mitigation scheme, market-based entry will be further chilled by the prospect of uneconomic entry artificially suppressing future price outcomes:

> I would expect the cost impacts to be spread more over time, but it appears that serious cost impacts have already begun. According to the January 28th release of Megawatt Daily (dated Jan 31, 2011), in an article on the likely impact of New Jersey's legislation, "Moody's said the potential in the long term is for the bill to be a material credit negative primarily to the unregulated power sector within New Jersey." As it turns out, this statement turned out to be issued on the same day that the New Jersey Governor signed the bill. I would expect markets to immediately react to these types of comments, driving down the value of stock and debt in the unregulated power sector, and in turn increasing the costs of funds to investors in electric utility infrastructure.

Shanker at 42:4-13. There is, in short, no economic basis for large-scale market-based new entry. It thus is no surprise that we have not seen such entry occur.

In sum, PJM's existing buyer market power mitigation scheme is fatally flawed and unjust, unreasonable and unduly discriminatory. Our proposed changes are just, reasonable and non-discriminatory. The Commission therefore should, at the outset, grant fast-track status. There is, in particular, no time for any stakeholder process, and all PJM market participants have been well aware that filings to fix the buyer market power mitigation scheme were close at hand. The Commission then should grant our complaint on an expedited basis, in time to allow mitigation to be strengthened before the next auction in May.

Alternatively, if the Commission were to decline to grant the expedited relief we seek—an outcome we would *not* consider consistent with the Commission's statutory mandate, or with the public interest—we set forth a request for clarification at the end of this pleading that could provide some measure of protection for the May 2011 auction, though nowhere near as effective as the tariff changes we seek.

OVERVIEW OF THE EXISTING TARIFF AND THE CHANGES WE SEEK

The PJM's Minimum Offer Price Rule has three stages. *First*, conduct screens are run to see whether mitigation will be triggered. *See generally* Shanker at 8:19–10:2. The conduct screen looks at each offered resource and reviews whether it offered below a specific threshold for an expected economic offer for new resources, or whether it proved to the Commission that it bid only its costs (minus PJM market revenues). If *either* of these conditions is met, the conduct screen is passed and the resource is not even evaluated for mitigation. *Second*, an impact screen is also conducted by rerunning the auction with mitigated offers to measure the effect of an uneconomic offer on market prices. The screen is passed unless the impact is large. *Third*, if both conduct and impact screens are failed, the uneconomic offer is mitigated (increased) to a competitive level for *one auction*.

We summarize the problems with this scheme below, along with our proposed solutions. We first address the issues that need to be resolved by mid-April 2011. We then address the issues that can be deferred.

I. *IMMEDIATE ISSUES*

A. Scope

In order to facilitate Commission action by mid-April 2011, we propose, for the next auction only, to apply the mitigation measures set forth below only to combustion turbine and combined cycle resources.

B. The Conduct Screen

Under the conduct screen currently employed in PJM, offers are mitigated only if they are less than 80% of the real, levelized net cost of new entry for the "asset class" of similar resources (as calculated by PJM). If there is no asset class, offers are mitigated only if they are less than 70% of the net cost of new entry of a combustion turbine. As Dr. Shanker explains, this effectively *caps* market prices substantially *below* the levels they need to *average* in order to support new entry. *See* Shanker at 20:22–21:21.

We propose the following changes to the current conduct screen employed in PJM: Any resource would pass the conduct screen if its offer is at least 100% of the net cost of new entry of its asset class. A resource offering below this threshold still would pass the conduct screen by making either of the following two alternative showings:

First, a resource should be deemed to have passed the screen, and thus not be mitigated, if it demonstrates that it is offering at its nominal, levelized unit-specific costs—and thus is economic. The market monitor would make these determinations in the first instance, although a resource could seek review by PJM. Both the market monitor and the resource could seek Commission review of any mitigation decision.

Second, in lieu of this review process, any resource, of any type, will be deemed to have passed the screen, and thus not be mitigated, if it establishes that it has not received any discriminatory payments, as determined at the time of the offer.

C. The Impact Test

Under the current tariff, if the conduct threshold is failed, then the impact test is applied. This test in effect reruns the auction to measure the impact that a mitigated offer would have on capacity clearing prices. Offers are mitigated only if there is at least a $25/MW-day or 20 to 30% change in clearing prices (depending on the size of the zone). *See* RPM § 5.14(h)(3). The impact standard allows material, artificial price suppression without any justification. *See* Shanker at 25:12-14.

We propose simply to delete the impact screen. All offers that fail the conduct screen should be mitigated, regardless of impact on the clearing prices. This also has the side benefit of eliminating any need to rerun the auctions to determine whether to mitigate, which will greatly simplify the process.

D. Mitigating Resources

Under the current tariff, any short-lead-time resource that fails the screens has its offer mitigated to 90% of the asset class cost of new entry. If there is no asset class, the offer is mitigated to 80% of the net cost of new entry. And there is an exception that removes all long-lead-time units from mitigation. *See* RPM § 5.14(h)(3). Again, this allows material, artificial price suppression without any justification. *See* Shanker at 21:14–25:2.

Under our proposal, uneconomic offers are mitigated to 100% of the nominal levelized unit-specific cost of new entry of the offering resource.

E. Terminating Mitigation

Under the current tariff, mitigation ends after only one auction, regardless of whether the resource clears or not. *See* RPM § 5.14(h)(4). We propose to continue the mitigation at least until the entrant has cleared in two auctions. As Dr. Shanker explains, clearing in two base residual auctions is the closest approximation to the Commission's recently approved standard for New York. Shanker at 57:12-21 & n.45.

In this same vein, the Minimum Offer Price Rule also has a sunset provision under certain conditions. We propose to eliminate that provision.

F. Exemptions to Mitigation

The current Minimum Offer Price Rule contains a number of exemptions. *See* RPM § 5.14(h)(1). We propose to immediately eliminate the following ones:

(1) the exemption for resources who are not deemed to be "net buyers";

(2) the exemption for self-supply;

(3) the exemption for certain state-sponsored projects; and

(4) the exemption for resources that are not "Planned Generation Capacity Resources."

II. DEFERRED ISSUES

We propose to defer the following issues, to be addressed in a subsequent PJM compliance filing:

(a) We submit that all resources, without exception, should be subject to buyer market power mitigation. This encompasses within it the questions whether mitigation should, as we submit, apply to (1) long-lead-time resources, (2) demand response resources, (3) renewable resources, and (4) uprates to existing units.

(b) In addition, if, as we propose, mitigation is applied to long-lead-time resources, certain adjustments will need to be made. For short-term resources, a determination of whether the resource is offering economically is made shortly before the auction. For long-lead-time resources, this determination should be made much earlier, at the time the interconnection agreement is signed.

(c) The existing tariff uses asset-class benchmarks. We submit that the better approach is to use the Reference Resource (a combustion turbine) cost of new entry—a figure used elsewhere in the market design.

BACKGROUND

I. THE CORE PRINCIPLES OF CAPACITY MARKET DESIGN

While capacity markets are barely ten years old, they have become an indispensable part of all three eastern RTOs. *See PJM Interconnection*, 115 FERC ¶ 61,079, *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power*, 113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006), *aff'd in relevant part sub nom. Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, *remanded by Me. Pub. Utils. Comm'n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010); *N.Y. Indep. Sys. Operator*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003); *N.Y. Indep. Sys. Operator*, 89 FERC ¶ 61,109 (1999), *order on reh'g and clarification*, 90 FERC ¶ 61,085 (2000). Even outside the RTOs, no control area operates without the equivalent of some mandated adequacy requirement, either directly or indirectly.

Capacity markets exist in order to cure the inefficiencies that occur whenever there are energy price caps, the need to achieve minimum requirements for installed capacity, and a desire to reduce volatility in cash flows for both generators and load in order to reduce the risk of price fluctuations reflected in the cost of capital. *See PJM Interconnection*, 115 FERC ¶ 61,079 at P 104 (noting the Commission's preference for designs that reduce price volatility). Ultimately, consumers benefit through more efficient market outcomes that result in lower consumer charges over the long run. *See PJM Interconnection*, 117 FERC ¶ 61,331 at P 141.

Arising out of this decade-long experience with capacity constructs are four general requirements for capacity markets to succeed, each based on bedrock economic theory and anchored in established Commission precedent. These requirements have become the screening criteria to consider initial capacity market design and design changes.

First, on average and over time, compensation needs to be sufficient to attract new entry and retain economic existing generation. *See ISO New England*, 125 FERC ¶ 61,102 at P 43 (2008), *reh'g denied*, 130 FERC ¶ 61,089 (2010). This means that on average and over time, the recovery from the bulk power markets for energy and capacity must result in payments equal to the net cost of new entry. *See Blumenthal v. ISO New England*, 117 FERC ¶ 61,038 at PP 82-87 (2006), *reh'g denied*, 118 FERC ¶ 61,205 (2007), *petition for review denied sub nom. Blumenthal v. FERC*, 552 F.3d 875 (D.C. Cir. 2009); *Devon Power*, 115 FERC ¶ 61,340 at P 114. Hence, if prices will be lower than average some of the time, they must be higher than average during other periods.

Second, capacity markets need to include locational and reliability price signals to reflect the fact that capacity in certain congested areas potentially has greater value than capacity located elsewhere. *See PJM Interconnection*, 119 FERC ¶ 61,318 at P 76; *Devon Power*, 103 FERC ¶ 61,082 at P 37 (2003). Capacity with attributes that provide for a differential reliability benefit should be recognized in the market design and compensated accordingly. This minimizes or eliminates the need for non-market arrangements such as Reliability-Must-Run contracts.

Third, all competitive resources within a given location need to be compensated at the same price. *See PJM Interconnection*, 117 FERC ¶ 61,331 at P 141; *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005), *reh'g denied*, 115 FERC ¶ 61,133 (2006); *Devon Power*, 110 FERC ¶ 61,315 at P 45 (2005); *N.Y. Indep. Sys. Operator*, 110 FERC ¶ 61,244 at P 65 & n.76, *order on reh'g*, 113 FERC ¶ 61,155 (2005); *N.Y. Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81. The law of one price for similarly-situated competitive units is a basic economic building block; price discrimination among competitive supply is inefficient and in the long run will increase costs. *See Blumenthal v. ISO New England*, 117 FERC ¶ 61,038 at P 83. Some exceptions might, however, be appropriate or necessary under circumstances where market power exercise and uneconomic entry already have distorted conditions. *See id.*

Fourth, the exercise of market power by both sellers and buyers needs to be mitigated to ensure that prices are neither artificially inflated nor artificially suppressed. *See N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 32, 100; *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005); *Midwest Indep. Transmission Sys. Operator*, 111 FERC ¶ 61,043 at P 78, *order on reh'g*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wisc. Pub. Power v. FERC*, 493 F.3d 239 (D.C. Cir. 2007). The exercise of market power by either side of the market is destructive for competition and long-term consumer welfare. *See Devon Power*, 115 FERC ¶ 61,340 at P 114.

II. COMMISSION PRECEDENT ON THE MITIGATION OF CAPACITY BUYER MARKET POWER

As noted above, each RTO with an organized capacity market has tariff provisions that seek to thwart exercises of buyer market power. They all work in a similar way. First they identify offers for capacity that are substantially below those that a competitive market participant would make. Then they mitigate those offers by repricing them to reflect an estimate of the price at which a competitive market participant would have offered the resource. Finally, the capacity auction is re-run with the substitute, competitive offers and the auction clearing price and capacity obligations are allocated accordingly. *See* Shanker at 9:5–10:2.

A brief review of the Commission orders addressing these provisions is instructive here. With respect to the NYISO In-City Installed Capacity Offer Floor, the Commission has held:

> We accept NYISO's proposal for net buyer mitigation, with modifications, in order to prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels.
>
> Large net buyers may have both the incentive and the ability to depress prices through uneconomic entry. … A large net buyer could acquire new capacity that is not needed in the market and whose costs exceed the market price. Such an investment would be inefficient, the net buyer would lose money on the capacity, and no rational seller would knowingly make such an investment. But the investment could benefit the net buyer because the additional capacity could reduce the market price for capacity and lower the net buyer's total capacity bill. If the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment. As a result, a large net buyer could have an incentive to make such an inefficient investment. However, this would result in the [load-serving entity's] captive ratepayers bearing the risk of uneconomic investment. The mitigation of net buyers' sales of capacity proposed by NYISO should help avoid this.

N.Y. Indep. Sys. Operator, 122 FERC ¶ 61,211 at PP 100-01. *See id.* at P 104 ("The Commission has accepted similar provisions to prevent uneconomic entry by net buyers in approving long-term capacity markets in both PJM and ISO-New England.") (citations omitted). The Commission subsequently excised the net-buyer requirement from the NYISO In-City Installed Capacity Offer Floor. *See infra* at 46.

Similarly, with respect to ISO-NE's Alternative Price Rule, the Commission explained that:

> [The rule] is a market power mitigation rule intended to discourage buyers who have the incentive and ability to suppress market clearing capacity prices below a competitive level from doing so. We have previously accepted rules to address such uneconomic entry in the capacity markets of ISO-NE, as well as in NYISO and PJM.

ISO New England, 131 FERC ¶ 61,065 at P 69 (citing *Devon Power*, 115 FERC ¶ 61,340 at P 113 (for ISO-NE)), *order on reh'g and clarification*, 132 FERC ¶ 61,122 (2010); *N.Y. Indep.*

Sys. Operator, 122 FERC ¶ 61,211 at PP 100-06; *PJM Interconnection*, 117 FERC ¶ 61,331 at PP 103-04).

Finally, in approving the PJM's capacity model, the Commission held that the Minimum Offer Price Rule:

> addresses the concern that net buyers might have an incentive to depress market clearing prices by offering some self-supply at less than a competitive level. … 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.

PJM Interconnection, 117 FERC ¶ 61,331 at PP 103-04. *See also PJM Interconnection*, 126 FERC ¶ 61,275 at P 191 (noting that the "Commission has previously expressed concern that uneconomic entry can be used by certain buyers to depress market clearing capacity prices and has authorized [Minimum Offer Price Rule]-type rules."), *order on clarification*, 127 FERC ¶ 61,104, *order on reh'g and clarification*, 128 FERC ¶ 61,157 (2009).

PJM's market monitor shares this understanding:

> The primary purpose of the Minimum Offer Price Rule in the PJM tariff is to prevent market participants from submitting uneconomic offers based on the receipt of out of market payments to artificially depress RPM auction prices. While it is unclear if the [Minimum Offer Price Rule] would apply to the offers that would result from the [New Jersey] legislation, those offers are not consistent with the intent of the [Minimum Offer Price Rule]. As a result of this ambiguity, we expect that the results of the upcoming RPM Base Residual Auction would be challenged by stakeholders whether the [Minimum Offer Price Rule] is applied to offers under the proposed legislation or not.

Letter from Andrew L. Ott, Senior Vice President, Markets, PJM Interconnection and Dr. Joseph E. Bowring, President, Monitoring Analytics to Lee A. Solomon, President, New Jersey Board of Public Utilities (Dec. 3, 2010) ("Bowring Letter"), http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM-MMU_Letter_to_NJ_BPU_20101203.pdf.

ARGUMENT

Our argument has four parts. *First*, we establish that the core mechanics of the existing buyer market power mitigation regime—the conduct and impact screens and the mitigation itself—are unjust, unreasonable and unduly discriminatory. *Second*, we establish that our proposed revisions to these core mechanics *are* just, reasonable and non-discriminatory (with two targeted issues to be deferred). *Third*, we establish that there should be no exceptions or loopholes in the mitigation rules, which all are easily exploited (with several targeted issues to be deferred). And *fourth*, we establish the need for expedition by setting forth the looming threat posed by the New Jersey Law.

I. THE CORE MECHANICS OF THE EXISTING MINIMUM OFFER PRICE RULE ARE UNJUST, UNREASONABLE AND UNDULY DISCRIMINATORY

The Minimum Offer Price Rule was adopted as part of the RPM Settlement, *PJM Interconnection*, 117 FERC ¶ 61,331, and—absent any major attempts to exercise buyer market power in RPM—has never been triggered. But in light of the recent New Jersey and Maryland schemes, discussed below at 57, its flaws now stand out in sharp relief. As we explain below, the core mechanics of the existing Rule are unjust and unreasonable for the following reasons:

(a) the conduct screen is too lax, effectively capping the market substantially below the actual net cost of new entry;

(b) the impact test permits massive downward price suppression;

(c) the "replacement" offers substituted by the mitigation scheme effectively cap the market substantially below the actual net cost of new entry; and

(d) limiting mitigation to one year renders the entire scheme ineffective.

Effective action on all of these issues is essential for an effective mitigation scheme, because the overall scheme is only as effective as the weakest link. We address each point in turn.

A. *The Benchmark Discounts in the Conduct Test Are Unjust, Unreasonable and Unduly Discriminatory Because They Effectively Allow Buyer Market Power to Cap Auction Prices at a Substantial Discount Below the Cost of New Entry*

The Minimum Offer Price Rule evaluates offers into RPM auctions to determine whether mitigation will be triggered. The conduct of the offering resource and the impact of the offers on clearing prices each are evaluated according to specific thresholds. And mitigation is triggered only if *both* the conduct and impact screens are failed. *See* Shanker at 9:5–10:2. As we establish below, the current screens unlawfully permit the exercise of buyer market power. To remedy this problem, as we explain in Section II of the Argument, the conduct screen should be set at 100% of the relevant benchmark.

Under the current Minimum Offer Price Rule's conduct test, a resource's offer is compared to a benchmark of 80% of the cost of the resource's asset class, or, if there is no asset class estimate, to 70% of the cost of a combustion turbine. RPM § 5.14(h)(2)(ii). Any resource may be offered at any price down to this floor and will escape the Minimum Offer Price Rule completely.

The Minimum Offer Price Rule's heavy discounts off of the applicable conduct benchmarks are unjustified and permit market participants to substantially, anti-competitively and artificially suppress auction price outcomes. They effectively invite and sanction anti-competitive offers well below the benchmark, but just above the identified thresholds. A competitive supplier would not offer new capacity resources at a price lower than cost (which is what the benchmarks are intended to reflect). But the mitigation floor permits offers up to 20 to 30% *below* expected long-run average costs. A would-be exerciser of buyer market power offering a sufficient amount of capacity at a 20 to 30% discount can depress auction clearing prices continually—*without* failing the test.

Load would hardly be satisfied with a seller-side market-power mitigation scheme that sanctioned sellers pushing capacity clearing prices *up* by 20 to 30% with impunity. Conversely, it is hard to see why buyer-side market-power mitigation should sanction pushing capacity clearing prices *down* by 20 to 30%. *See infra* at 29 (text and discussion of Dr. Shanker cited there).

B. The Impact Threshold Is Unjust, Unreasonable and Unduly Discriminatory Because It Permits Large Downward Price Distortions

Under the impact test, PJM is required to conduct a sensitivity analysis comparing the capacity clearing price with or without mitigation. This test, by its terms, exempts offers already found to be uncompetitively low whenever they suppress capacity prices by less than (1) $25/MW-day or (2) 20 to 30% (depending on the size of the Locational Deliverability Areas). As we explain below, this provision eviscerates the entire mitigation scheme and thus is unjust, unreasonable and unduly discriminatory. As we explain in Section II of the Argument, our proposal properly remedies the problem by simply deleting the impact screen.

Some simple examples easily prove the problems caused by the impact test. Turning first to the unconstrained part of PJM, the $25/MW-day exemption effectively means that there currently is *no* buyer market power mitigation in that region. For the 2012/13 Base Residual Auction, the capacity clearing price in the unconstrained portion of PJM was $16.46/MW-day. *See* PJM, *2012/2013 RPM Base Residual Auction Results* at 1, http://ftp.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx. Under the current tariff, capacity buyers would have been free to suppress capacity prices all the way to $0/MW-day, and, because of the impact threshold, the Minimum Offer Price Rule would have had done nothing to stand in the way.

We would see similar results for the 2013/14 Base Residual Auction, where the capacity clearing price in the unconstrained portion of PJM was $27.73/MW-day and over 150,000 MW of Unforced Capacity cleared. *See* PJM, *2013/2014 RPM Base Residual Auction Result* at 1, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx. Once again, under the current tariff, the effect of the impact threshold would have been equally grave. Capacity buyers could have used their market power to suppress capacity prices by almost 90%, to $2.74/MW-day. Annual capacity compensation in the unconstrained portion could have been reduced by almost $1.4 billion. Yet even this substantial impact would have been considered so *de minimis* that no mitigation would have been required.

The impact screen eviscerates mitigation just as effectively in the constrained Eastern Mid-Atlantic Area Council region, which includes New Jersey. In the 2013/14 Base Residual Auction, approximately 33,000 MW of Unforced Capacity cleared at $245/MW-day in that region. *Id.* at 10. A 20% price suppression, as the impact threshold permits for a region this size, would have reduced the clearing price by up to $49/MW-day. A price suppression of this magnitude would have reduced annual capacity compensation (and hence the market signals for new entry) in that region alone by over $590 million. *See* Shanker at 26:8-15. And once again, this would have been considered *de minimis* under the impact threshold, and therefore unworthy of mitigation.

C. It Is Unreasonable to Mitigate—or Effectively Reprice—Offers to a Discount off of the Applicable Benchmark

The current Minimum Offer Price Rule mitigates uneconomic entry to "90 percent of the applicable estimated" Net Asset Class Costs of New Entry, "or, if there is no applicable estimated cost, … to 80 percent of the then-applicable" net cost of new entry of the Reference

Resource. RPM § 5.14(h)(3). Once again, this provision is unjust and unreasonable because it allows artificial price suppression of between 10 to 20%. This itself is enough to make the exercise of buyer market power feasible and profitable. As we establish below, the proper course is to reset offers to 100% of the applicable benchmark. *See infra* at 29 (text and discussion of Dr. Shanker cited there).

D. It Is Unjust, Unreasonable, and Unduly Discriminatory to Limit Mitigation to One Year

1. Mitigating for Only One Year Is Effectively the Same as No Mitigation at All

The Minimum Offer Price Rule mitigates an uneconomic resource only "for the first Delivery Year in which [the resource] qualifies" as a Planned Generation Capacity Resource. RPM § 5.14(h)(2). This means that no resource will be mitigated for more than one Base Residual Auction. And this renders the Minimum Offer Price Rule, as currently constituted, a dead letter. As explained below, we propose to continue mitigation until a resource proves that it is economic by clearing in two Base Residual Auctions.

As Dr. Shanker notes, even the single-year mitigation limitation is easily circumvented by offering a resource into an auction at a very high price prior to the time when it is anticipated to be ready. *See* Shanker at 34:1-20. It then would fail to clear, and finish its one-year mitigation period close to its start-up date.

Even without such machinations, a one-year mitigation period does virtually nothing to remove the ability and incentive to exercise buyer market power. The resources used to artificially depress capacity prices have a useful life of several decades. An uncompetitive resource will depress capacity market clearing prices for every year it participates, not merely the first one. Mitigating such a resource for just one year will deter only the most feebly motivated attempts at market power exercise.

Moreover, the Minimum Offer Price Rule only mitigates sell offers made into *Base Residual Auctions*. Offers into Incremental Auctions are outside the scope of the Minimum Offer Price Rule. Any sponsored resource that was prevented from clearing in one Base Residual Auction by the Minimum Offer Price Rule will face no obstacles if offered into the subsequent Incremental Auctions for that same delivery year. While prices and volumes in the Incremental Auctions may be smaller than those in Base Residual Auctions, the exemption for Incremental Auctions still permits resources that are otherwise mitigated by the Minimum Offer Price Rule to begin to suppress prices (and earn some capacity revenues) even in the first year of operation. In short, the Minimum Offer Price Rule at best will prevent market power distortions in the *first* capacity auction for *one* delivery year. After that, buyer market power has free rein. And that is unjust, unreasonable and unduly discriminatory.

2. *The Commission Just Required NYISO to Mitigate Indefinitely Until a Market Test Is Met*

While the inadequacy of limiting buyer-side mitigation to no more than one auction for one year is almost self-evident, the Commission recently provided guidance that effective buyer-side mitigation in capacity markets must meet a far higher standard before mitigation can be terminated. *See N.Y. Indep. Sys. Operator*, 133 FERC ¶ 61,178 (2010), *reh'g pending* ("*NYISO*").

In *NYISO*, the Commission considered a NYISO proposal to modify the length of time resources are mitigated under the NYISO's In-City Installed Capacity Offer Floor, the Minimum Offer Price Rule's more effective sibling. At the time of the filing, NYISO's In-City Installed Capacity Offer Floor mitigated resources for "the longer of: (1) six capability periods (approximately three years) … or (2) the period of years that it takes the demand for capacity to grow into available supply." *Id.* at P 3 (footnote omitted). Under NYISO's proposal, resources would be mitigated "for a number of years equal to the shorter time period calculated using two alternative methodologies, with a maximum duration of 30 capability periods (approximately 15 years) and a minimum duration of six capability periods (approximately three years)." *Id.* at P 12. NYISO argued that otherwise "mitigation might last for decades and might even surpass the life of a new entrant's facility," and that this was "beyond what is needed to discourage any realistic uneconomic entry strategy." *Id.*

The Commission rejected the NYISO proposal to cap the length of mitigation. *Id.* at PP 47-52.

> [W]e do not agree with NYISO that a thirty capability period maximum is justified or linked to the need for buyer-side mitigation. NYISO justifies this maximum with the argument that a rational potential market entrant will not be willing to accept mitigation for such a long time-period on the uncertain hope that it will reap the benefits of uneconomic entry. This assertion may be true, but a thirty capability period maximum is arbitrary and not related to the central objective of buyer-side mitigation, which is prevention of uneconomic entry by those that have the ability and incentive to use uneconomic entry as a tool of price suppression.

Id. at P 51. Instead, the Commission held that any "resource [that] is not clearing in the market … is uneconomic," and ordered that "mitigation should continue, *regardless of how long* [the resource] has already been subject to mitigation." *Id.* (emphasis added). The only way a resource should be able to escape mitigation is by proving that it is economic and by clearing at its mitigated price, which, for any economic resource, can be expected to happen in a capacity auction:

> [W]e find reasonable NYISO's proposal to have the duration of in-City buyer mitigation turn on actual acceptance of the resource's capacity in the market at the offer floor[.] … [S]ubject to a minimum period of mitigation of six capability period (approximately three years), mitigation would be lifted for a new in-City generation resource when … the capacity clears in 12 monthly auctions at the offer floor.

Id. at P 49. A resource that clears only in part would be freed from mitigation only to the degree it cleared. *Id.*

The Commission's reasoning and ruling in *NYISO* is doubly instructive in this case: *First*, the Minimum Offer Price Rule ceases mitigating resources after *at most* one year, regardless of whether the resource clears or not. In *NYISO*, even the proponents of relaxing NYISO mitigation only argued that *fifteen years* of mitigation were sufficient to extinguish economic motives for market power exercise, *see id.* at P 16, and even they supported a *floor* of at least *three years* of mitigation. *Id.* at P 17. The Commission rejected that fifteen-year time limit on mitigation as arbitrary, and instead permitted mitigation to continue indefinitely. *Id.* at P 51. The Minimum Offer Price Rule's cap of at most one year falls far below the much higher level that the Commission held to be too little in *NYISO*. *Second*, the Commission adopted a market test for when to end mitigation. Resources that prove themselves economic by clearing at a competitive price are freed from mitigation. Resources that do not pass this test are mitigated without any time limit. The Minimum Offer Price Rule should adopt the same test, with slight adjustments for the technical difference between the NYISO and PJM auction procedures.

II. THE CORE MECHANICS OF OUR PROPOSED TARIFF CHANGES ARE JUST, REASONABLE AND NON-DISCRIMINATORY

We propose several reforms to strengthen the Minimum Offer Price Rule. On the mitigation triggers, we propose to appropriately tighten the conduct screen and to eliminate the impact screen. We also propose to increase the mitigated-to price and to extend the mitigation period using a market-based clearing criterion. We also provide an example of what a revised, effective Minimum Offer Price Rule should look like. *See* Attachment A ("Revised MOPR").

A. A Revised Minimum Offer Price Rule Should Revise the Conduct Screens

In order to effectively control buyer market power, consistent with the mitigation of seller-side market power and other parts of the Minimum Offer Price Rule, the thresholds for buyer-side mitigation should be revised as follows. We propose a revised conduct screen to measure whether mitigation should be triggered. *See* Revised MOPR (2). Under this revised approach, any resource would pass the conduct screen if its bid was at least 100% of the net cost of new entry for its asset class.

A resource bidding below this 100% threshold could still, however, pass the conduct screen—and thus be exempt from mitigation—if it met either of the following conditions:

First, a resource can pass the conduct screen if it demonstrates its unit-specific costs. *See* Revised MOPR (3)(ii). This would be the full, nominal, levelized costs of the individual unit, including projected costs and costs already sunk (if any), but using a market—not individual—cost of capital. Any unit could justify its costs at the time of the auction.

Second, a resource can satisfy the entire mitigation regime by establishing that it has not received any discriminatory payments, as determined at the time of the offer. *See* Revised MOPR (3)(iii).

We discuss key features of this proposal below.

1. A 100% Benchmark Is Just and Reasonable, Both as a Conduct Screen and as the "Mitigated-To" Price

Our first proposal is to replace the basic 80% (or, in some cases, 70%) conduct threshold to 100% of the appropriate nominal levelized cost of new entry. *See* Shanker at 52:15-21. Any resource bidding below this threshold will be deemed uneconomic unless it met one of the other screens excusing mitigation.

The 100% level is appropriate because a lower threshold permits a significant amount of buyer market power to be exercised. As Dr. Shanker explains:

> A conduct threshold of 80% or 70% permits offers 20% to 30% below economic levels to go unmitigated. This permits the extensive exercise of buyer market power before mitigation is even triggered just by bidding in subsidized new entry at a level slightly higher than the screen, e.g., 81%. Consider the effect of a 20% threshold in the EMAAC LDA. The EMAAC net Cost of New Entry was approximately $260 per MW-day for the last Base Residual Auction. Twenty percent equates to $52 per MW-day. Applied to the approximately 33,000 MW of capacity inside the EMAAC locational delivery area, there would be a permissible total annual dollar exercise of buyer market power of $626 million *before mitigation is even considered* ($52/MW-day x 365 days x 33,000 MW = $626,340,000).

Shanker at 21:3-13.

In addition, setting a benchmark below 100% also defeats one of the core objectives of the capacity market, by preventing the market from clearing, on average and over time, at the net cost of new entry. *See* Shanker at 56:7-17. We expect that opponents of effective mitigation may object that some discount nevertheless should be imposed in light of potential inaccuracies in the benchmark. But as Dr. Shanker explains, this objection is without merit:

> Actually, in this specific situation that type of logic does not apply. In fact, other considerations support mitigation to a higher substitute Sell Offer, not a lower one. Ideally, any bid from a subsidized party would be excluded. However, if such bids are allowed, they must be mitigated to at least 100% of their nominal levelized costs to prevent adverse effects in the operation of the capacity market. There are two main reasons for using 100% as a lower bound. First, in the presence of market power, the mitigation floor offer is likely to become the *cap* on prices for capacity in the market. The definition of the "mitigated-to" target price in this situation is a nominal levelized long-term price that represents the *average compensation* that is needed to support new entry over time. Buyers with market power can act to eliminate the ability of prices to rise above the offer floor, which would be possible under the PJM demand curve structure, but for the market power. The notion that the prices would be capped at average some of the time, and less than average other times clearly points out the problem: who will privately invest under such conditions? Similarly, this clarifies that while the mitigation is to the appropriate average value, that value may be too low to achieve the goal of reproducing long-term competitive market conditions, as private entry will still be discouraged from entering the market absent a subsidy.

Shanker at 22:4-20.

In this same vein, opponents of effective mitigation also might argue that a discount off of the benchmark is appropriate here because the offers of sellers in the capacity and energy markets typically are mitigated to 110% of marginal cost.[4] But this overlooks the very real point, stressed by Dr. Shanker, that the effects of setting the benchmark too low, versus too high, are wildly asymmetrical:

> In the energy market, mitigation often occurs when there is a lack of competitive supply alternatives. Thus there is concern regarding not forcing a supply at what might be less than cost because the supply must be used, there typically is no alternative. That is not the case with the exercise of buyer-side market power in the capacity market. If the supply from a specific party offering subsidized capacity is mitigated, no barriers are created for others to put forward competitive alternatives. I discuss the importance of alternative competitive supply and its relevance to setting mitigation levels further below. The implications of this can best be seen by looking at the issue of replicating competitive results from a "cost of the errors" perspective. That is, what is the relative harm or benefit from choosing too high of a value for the substitute Sell Offer versus too low a value. When this analysis is done, and the availability of competitive alternatives is taken into account, the clear conclusion is that it is better to have an upward bias in the substitute Sell Offers, if there is going to be any bias at all. Indeed, a value greater than 100% could easily be justified in the current circumstances. For example, if the mitigated price set at the nominal levelized Unit Specific Net Cost of New Entry were deemed too high, what is the harm? The worst that happens is that the mitigated offer fails to clear, and presumably the new resource would not be built. This would occur because either there was no need for it, or if there was a need, it was filled by a lower-cost alternative competitive supplier. This is hardly a bad result, and in fact, is what should happen in a market. Empirically we know we have significant additional supply in PJM. Alternatively, if the mitigated price is too low, and effectively sets a cap on the market below the actual cost of new entry, competitive entry is eliminated, prices are suppressed,

[4] For example, the RPM's offer price cap for existing resources permits a premium of 10% above the estimated cost benchmark. RPM § 6.8(a) (including a 10% "Adjustment Factor" "to provide a margin of error for understatement of costs"). This premium, in contrast to the benchmark discounts discussed here, has at most a *de minimis* effect on price levels in a competitive market and no potential to unravel the market overall. There are several reasons for this. *First*, the premium is over an estimate of avoidable cost which by its nature is in order of magnitude smaller than the cost of new entry. Hence, the impact on auction clearing prices of 10% of the avoidable cost premium will be proportionately smaller and less significant than 10% of the cost of new entry discount. *Second*, because a healthy capacity market will equilibrate around the net cost of new entry, the avoidable-cost-based bids of existing generators can be expected to be heavily infra-marginal, with or without a 10% premium. As a consequence, one would expect this premium to have no effect on either clearing prices or capacity obligations.

> and price discrimination is allowed. This assures the destruction of the market, because by definition the prices are being set at levels such that they will never be compensatory for a new entrant. No one will enter a market where the expected revenues are capped at less than the needed average price.

Shanker at 22:23–24:4. The "cost" of mitigating to too low a level is, in sum, *much* more severe than the "cost" of mitigating to too high a level. Setting mitigated prices too low can cause billions of dollars of deadweight losses, while setting them too high is basically cost-free.

The choice here, we submit, is simple: mitigate to 100%. This outcome, as Dr. Shanker's testimony explains, conforms to the long-standing teaching of the United States Supreme Court that the purpose of the law is "'the protection of *competition*, not *competitors*.'" *Brunswick Corp. v. Pueblo Bowl-O-Mat*, 429 U.S. 477, 488 (1977) (quoting *Brown Shoe Co. v. United States*, 370 U.S. 294, 320 (1962)); *Copperweld Corp. v. Independence Tube Corp.*, 467 U.S. 752, 767 n.14 (1984); *Brooke Group Ltd. v. Brown & Williamson Tobacco Corp.*, 509 U.S. 209, 224 (1993); *NYNEX Corp. v. Discon*, 525 U.S. 128, 135 (1998) (a Sherman Act claim "must allege and prove harm, not just to a single competitor, … but … to competition itself"). The prime goal here should be to protect the market from distortion, because that is the greatest source of severe harm. Mitigating to 100% is the best way to achieve that goal.

We recognize that the other organized capacity markets, like the current PJM regime, use a discounted benchmark for buyer-side mitigation. But these provisions typically were implemented as the result of settlements. There has *never* been a litigated resolution of the arguments we present here. In particular, the Commission has never been presented with the stark contradiction between (1) the fundamental design criterion for organized capacity markets—the need to average the actual net cost of new entry—and (2) using a steep discount off of the cost of new entry for detecting the exercise of buyer market power, effectively capping price outcomes so that they remain below competitive levels. This is a recipe for market failure.

It is neither a reasonable reading of the Commission's prior orders, nor a just, reasonable, and non-discriminatory approach to setting rates, to create and maintain a market design that sows the seeds of its own destruction. The Commission thus should not—and, we submit cannot, consistent with its statutory mandate and minimum standards of reasoned decision-making—consider itself bound by prior precedent that did not give reasoned consideration to these critical core problems.

One final point on this issue merits discussion, though it can and should be deferred to the second stage of this case. Dr. Shanker concludes that, in his expert opinion, the ideal benchmark would be based on the net cost of new entry *for the Reference Resource*, a combustion turbine. Shanker at 56:9-13. We propose here to continue using the net cost of new entry for the asset class of the resource. *See* Revised MOPR (1).

Dr. Shanker agrees that the asset class benchmark would be adequate. Shanker at 8:8-16. Ideally, however, he prefers to base the benchmark on the Reference Resource, because the Reference Resource is a combustion turbine and combustion turbines are expected to be the marginal resources in an effective capacity market in PJM.[5]

We propose to use asset class benchmarks for the purely practical reason that the current version of the tariff bases the benchmark on the asset-class cost. Given the urgent need for action, consideration of Dr. Shanker's proposal to use the Reference Resource can be deferred with the other "phased" issues.

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[5] Dr. Shanker's specific proposal is to screen conduct on the basis of the Reference Resource, a combustion turbine, and "mitigate to" a unit-specific net cost of new entry. This effectively results in mitigation to the lesser of the reference or unit specific value assuming rational behavior by bidders.

2. *The "No-Subsidy" Off-Ramp*

We also propose to make the entire buyer-mitigation regime less burdensome for all stakeholders, and easier to administer, by proposing simply to terminate the mitigation process for any resource that can establish that it will not receive any form of subsidy.

New entry could fail a conduct screen for one of two reasons: (a) a competitive entrant may simply have expectations about future energy and ancillary service revenues that are different than the estimates embedded in the benchmark, or (b) a resource can have some other form of financial support, such as the type of contract proposed by the New Jersey Law. The first situation does not, in our view, need to be addressed through buyer mitigation—it is not causing artificial price suppression, and reflects, instead, normal business conduct. The second, in stark contrast, *does* need to be addressed through mitigation. We therefore can focus the mitigation process on resources most likely to cause artificial price suppression if we allow resources to exit that process by establishing that they are not receiving any subsidy. Shanker at 53:2-12.

The market monitor already is recognized as capable of making these types of determinations because there are tariff provisions tasking it with detecting and reporting alleged seller-side market manipulation schemes. The market monitor also is well positioned to make the initial determination regarding subsidies because it has access to a broad section of both public and confidential information. However, such general information will need to be supplemented by specific information only available to the market participant who seeks to offer the new resource. *See* Revised MOPR (3)(iii).

Given the variety of possible schemes for subsidizing uneconomic entry, it is essential that the market monitor and PJM have the authority to acquire all necessary information for market participants seeking an exemption, and that they have the opportunity to subject any potential arrangement to complete economic analysis, rather than being bound by narrow categorizations inviting evasion. *See generally Prohibition of Energy Market Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202 (2006) (recognizing the need for flexibility in identifying market manipulation in order to avoid evasion). And the Commission would, of course, always have final say on any determination.[6]

We propose that the tariff require that the information submitted to the market monitor be accompanied by a certification executed by a responsible corporate officer. This is both common sense and common PJM practice. In similar circumstances, where the appropriate PJM decision depends on information properly within the knowledge of a market participant, the market participant must certify the accuracy of this information. *See, e.g.*, PJM Tariff § 6 (requiring "sworn statement of … duly authorized officers or other representatives … that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision"); § 29.2(vii) (requiring a "statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed" satisfy certain conditions); § 116 (requiring market participants to "file … the Deactivation Avoidable Cost Rate, along with applicable cost support and a certification by an officer of the Generation Owner or its Designated Agent attesting to the accuracy").

As in these other cases, intentional or reckless submission of false, misleading, or incomplete information would subject the market participant to very significant penalties. Under the Commission's Revised Penalty Guidelines, an intentional misrepresentation of this type that leads to billions of dollars of artificial price suppression could potentially create very large

[6] Needless to say, compliance with this tariff provision would not shield otherwise unlawful conduct of market participants from Commission review and prosecution. In particular, if a market participant were to devise a market manipulation scheme which somehow evaded the tariff's definition of "discriminatory payments," this would only render the scheme tariff-compliant. It would not protect the participant from a charge of market manipulation.

penalty levels (in addition to potential disgorgement of ill-gotten gains). *See Revised Policy Statement on Penalty Guidelines*, 132 FERC ¶ 61,216 (2010).

B. A Revised Minimum Offer Price Rule Should Eliminate the Impact Threshold

A preceding discussion amply demonstrates the excessive size of the Minimum Offer Price Rule's current impact thresholds. *See supra* at 23. In actuality, however, there is no justification for *any* impact threshold, no matter how moderate. *See* Shanker at 54:3-6. We are unaware of any Commission order holding that demonstrable, readily remediable exercises of market power in jurisdictional markets must be given a pass if they are not "too excessive." Rather, the Commission seeks to mitigate *all* instances where market power is exercised and has never confined itself to only the most extreme examples.

Mitigating the exercise of buyer market power without any impact threshold is readily workable. Other components of the Minimum Offer Price Rule ensure that only genuine exercises of market power are identified and targeted, and that the magnitude of the mitigation matches the magnitude of the exercise of market power. Large exercises of market power with large effects will result in substantial mitigation, affecting clearing prices and the assignment of capacity obligations in a commensurate manner. Small exercises of market power with small effects will result in only slight mitigation, affecting clearing prices and capacity obligations only marginally, if at all.

It might be argued that an impact threshold is wise if, for example, there was an enormous administrative or economic burden created by even the most minor mitigation. In that case, some might argue that mitigating truly *de minimis* market power exercises would, on net, do more harm than good. But that is not the case here. The entire apparatus of the Minimum Offer Price Rule—including data collection, verification, and review and calculation of the outcomes of various alternative, hypothetical capacity auction sensitivities—must be engaged regardless of the impact threshold. Only after the various hypothetical auction sensitivities have been fully evaluated can PJM determine how large the impact of any particular identified market power exercise would be, and whether the impact threshold has been met. And at that point, there no longer is any doubt about whether the Minimum Offer Price Rule process is worth undertaking—all of the effort already has been expended. The only remaining question is whether an auction with an outcome artificially distorted by the exercise of market power should be allowed to go into effect, or whether, instead, an already-calculated alternative auction outcome, purged of the effects of market power, should be made effective. Even if, in some cases, the difference between distorted and correct auction outcomes is minor, there is no reason to pick the distorted outcome over the correct one.

In addition, none of the Minimum Offer Price Rule's siblings in other RTOs—the NYISO's In-City Installed Capacity Offer Floor and any version of ISO-NE's Alternative Price Rule currently under discussion—have an impact threshold beneath which buyer market power exercise is permitted. Our proposal conforms the approach in PJM with these other markets.

In sum, the impact threshold is unnecessary and harmful. It should be deleted without replacement. *See* Revised MOPR.[7]

C. A Revised Minimum Offer Price Rule Should Mitigate Resources Until They Prove Economic

We recommend adopting similar rules to those recently approved in NYISO to address the period of time over which to extend the mitigation.

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[7] Eliminating the impact screen also has the side benefit of significantly simplifying the mitigation process. Without an impact test, there is no longer any need to run the capacity auction multiple times with different sets of mitigated and unmitigated bids. The market operator would just mitigate bids that fall within the Minimum Offer Price Rule's constraints before the auction and then run the auction just once with all the bids as mitigated. The outcome of this auction would then just be to determine the price levels and capacity obligations. With this simplification, a great deal of tariff language can be eliminated and the Revised Minimum Offer Price Rule does so by eliminating section 5 entirely.

First, as in *NYISO*, 133 FERC ¶ 61,178, the Minimum Offer Price Rule's implicit limitation to one Base Residual Auction should be struck. *See* Revised MOPR (2).

Second, in a way similar to *NYISO*, resources that clear in two capacity auctions should thereafter be permanently exempt from mitigation. *See* Revised MOPR (3)(i).

While *NYISO* required resources to clear for twelve auctions, each NYISO auction covers only one month. *NYISO*, 133 FERC ¶ 61,178 at P 49. Each capacity auction in RPM covers a delivery year. As Dr. Shanker explains:

> [In NYISO], with a monthly clearing process, the requirement was to clear in twelve auctions, which didn't necessarily need to be consecutive. Thus, because typically demand is higher, and capacity lower during the summer, the most likely clearing scenario is during two summer periods. Because PJM clears annually based on summer requirements, the use of two Base Residual Auctions is directly analogous.

Shanker at 57:16-21. Clearing in two RPM auctions thus is the rough equivalent of clearing in twelve NYISO capacity auctions.

Third, for a resource that previously has cleared only in part, it is only the cleared part that becomes exempt from mitigation. For example, if a 500-MW resource was offered in the previous Base Residual Auction, but only 200 MW cleared, the 200 MW thereafter become effectively exempt from the Minimum Offer Price Rule; the other 300 MW that did not clear remain subject to mitigation until they do clear. Accounting for the different time periods in NYISO and PJM capacity markets, this treatment is consistent with the Commission's previously announced rule. *See NYISO*, 133 FERC ¶ 61,178 at P 49 ("only the consistently-cleared portion of the capacity of a given resource over a total of 12 monthly auctions should have its offer floor mitigation lifted").

Fourth, we propose a related provision in the Revised Minimum Offer Price Rule to mitigate resources that originally were excused from mitigation because they were not receiving discriminatory payments, but then are subsequently determined to have in fact received discriminatory payments. *See* Revised MOPR (3)(iii). This provision serves two functions. To begin with, it prevents market participants whose original disclosures of potential subsidies to the market monitor were incorrect or incomplete—willingly or, as is possible, due to lack of knowledge—from profiting as a result. If the market monitor or the Commission reverses a determination that a resource is exempt, in light of information later discovered, mitigation would restart prospectively. Additionally, in case the Commission is unable to rule on this complaint before the May 2011 Base Residual Auction, and New Jersey or Maryland successfully achieve subsidized uneconomic entry, market participants will nevertheless become subject to mitigation if the Commission approves a revision to the Minimum Offer Price Rule, and the market monitor determines that the New Jersey or Maryland resources received discriminatory payments (as they clearly do).

Finally, the Minimum Offer Price Rule currently includes a provision that entirely eliminates mitigation in certain circumstances if there is a positive net demand for new resources in two consecutive years. RPM § 5.14(h)(5). Mitigation can be reinstated only under certain limited conditions. There is no justification for this provision because new resources, even if mitigated, would be expected to clear when there is a need for new entry. It should be deleted. *See* Revised MOPR. All buyer market power should be mitigated.

III. MITIGATION SHOULD APPLY TO ALL TYPES OF RESOURCES WITHOUT EXEMPTION, BUT ONLY SOME EXEMPTIONS NEED TO BE ADDRESSED NOW, WHILE OTHERS CAN BE DEFERRED

A. We Propose to Limit Mitigation of Certain Resource Classes Until More Contentious Issues Can Be Resolved in Further Proceedings

In our view, the full buyer mitigation regime should apply to all resources. But we recognize the reality presented by the compressed time frame here. We thus propose to apply mitigation only to combustion turbine and combined cycle resources for the next auction. We propose to defer, to a subsequent stage of the case, the treatment of demand response, renewables, and long-lead-time resources.

The Commission previously has taken similar action to immediately mitigate *sellers* in organized markets, while setting more complex longer-term issues for future proceedings. As the Commission recently explained:

> The Commission has found in other contexts that uncertainty at the start-up of a new market design justifies the implementation of interim measures to smooth the transition to a new market, so as to protect customers from potentially unjust and unreasonable rates during the early stages of implementation. … The Commission concluded that this uncertainty justified the implementation of interim measures, during the first four months of its new market, to guard against potentially unreasonable prices during the early stages of implementation. We find that similar interim measures may be justified in this case. However, we also expect the CAISO to consider the effectiveness of the numerous other market power mitigation measures proposed.

Cal. Indep. Sys. Operator, 130 FERC ¶ 61,122 at P 56 (2010) (footnote omitted). *See also Okla. Gas & Elec. Co.*, 124 FERC ¶ 61,239 at PP 53-55 (2008) (imposing interim seller market power mitigation in context of merger); *Midwest Indep. Transmission Sys. Operator*, 120 FERC ¶ 61,250 at P 35 (2007) (imposing interim seller market power mitigation in light of the fact that "market will likely undergo significant changes, including the anticipated implementation of its long-term resource adequacy plan and development of demand resources, that may necessitate adjustments to the market monitoring and mitigation plan"), *reh'g and clarification denied*, 122 FERC ¶ 61,178 (2008).

To avoid any ambiguity, we propose tariff language that, for the May 2011 auction only, expressly limits the application of the new mitigation to combustion turbines and combined cycle resources, which are the principal threat to the integrity of the upcoming Base Residual Auction. *See* Revised MOPR (3)(v).

It is essential, however, that the Commission set a clear time-table for further proceedings. While blanket exemptions for many resource classes hopefully will not adversely effect the May 2011 auction outcomes, future auctions will face more severe risks of downward price suppression. In order to avoid a replay next year of the same situation, it is critical to proceed with the examination of these other exemptions now.

B. Immediate Issues

1. The Commission Should Remove the Net-Short Requirement

a. Overview

The Minimum Offer Price Rule is fatally flawed because it permits mitigation of offers only by sellers that are considered net short (because their obligations to purchase capacity substantially exceed their capacity sales). Specifically, the Minimum Offer Price Rule predicates mitigation on the following condition:

> The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts.
>
> A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply.
>
> An "actual retail load obligation" shall mean the [load-serving entities'] combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement.
>
> A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the [Base Residual Auction], under contract for the Delivery Year.

RPM § 5.14(h)(2)(iii). The Minimum Offer Price Rule never mitigates any capacity offer made by any Capacity Market Seller that is not net short.

The apparent rationale for this blanket exemption is the argument that a capacity market participant that does not, on net, purchase substantially more capacity than it sells would not benefit from price suppression, and therefore presumably would not have any intent to suppress prices. This rationale has some support in logic and economics but in practice is impossible to administer effectively. Not only is the specific net-seller requirement of the Minimum Offer Price Rule so overbroad as to allow easy circumvention of the entire rule, it appears to be administratively impossible to craft a net-seller requirement that does not suffer the same defect. Moreover, a net-seller requirement, even if possible, is not necessary. The Commission therefore rightly has ordered the complete deletion of any such requirement in other capacity markets.

b. The Minimum Offer Price Rule's Net-Short Requirement Exempts Even Substantial Capacity Buyers

The Minimum Offer Price Rule's net-short requirement, even accepting the rationale proffered above, is seriously flawed because it is in fact a *large*-net-short requirement. *See generally* Shanker at 30:16-20. Market participants can be substantial net purchasers of capacity (and have the concomitant incentive to suppress prices) and still be completely exempt from mitigation due to the Minimum Offer Price Rule's net-short requirement. Only when the net purchases of capacity exceed 10% of the Locational Deliverability Area's reliability requirement (5% in large Locational Deliverability Areas) does mitigation set in. So, for example, a load-serving entity that purchases up to 9.9% of all of the capacity in a small Locational Deliverability Area would be completely exempt thanks to the Minimum Offer Price Rule's net-short requirement. So would a load-serving entity that purchases 30% of all capacity in such a Locational Deliverability Area and sells 20.1% of the capacity in that Locational Deliverability Area to suppress capacity market prices.

The effect of the net short requirement on capacity prices can be substantial. *See* Shanker at 30:21–31:15 (showing example of price impact). The fact that the Minimum Offer Price Rule's net-short requirement permits such substantial market distortions and exercises of market power with impunity, standing by itself, is sufficient to render the net-short requirement unjust and unreasonable.

c. The Net-Short Requirement Allows Complete Evasion of the Minimum Offer Price Rule

While the requirement of a *large* net-short position permits substantial evasion of the Minimum Offer Price Rule, a more substantial loophole in the net-short requirement makes it trivially easy to entirely bypass the Minimum Offer Price Rule: The Minimum Offer Price Rule's net-short requirement is based on the position of the Capacity Market Seller who offers the resource into the auction. RPM defines this term as follows:

> "Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

RPM § 2.11. There is, however, nothing in the economics of exercising market power that requires (1) the beneficiary of the scheme—the party that profits from the price suppression because it has an actual or constructive short position in the capacity markets—and (2) the capacity seller—the party that actually offers the resource into the capacity markets at uncompetitive prices, and thereby effects the price suppression—to be the same or even closely related. If one party offers the capacity resource, and another, separate party has the short position, the entire scheme will escape any mitigation under the current Minimum Offer Price Rule because of the net-short requirement.

The only argument that could be raised against such a separation is that the capacity seller would decline to participate because it would suffer a loss from the uncompetitive offer, while all the benefits would accrue to the separate party with the short position. But, this missing link can easily be supplied. All that is required to coordinate the seller and the beneficiary is a contract or other arrangement in which the beneficiary shares a sufficiently large part of its profits to make the capacity seller's participation also profitable.

One effective type of side arrangement is a contract for differences requiring the seller to offer a resource at an uncompetitively low price in return for the beneficiary holding the seller harmless for the resulting price suppression. That is, of course, the arrangement used in the New Jersey scheme. *See infra* at 57-60. Other sponsors of buyer market power schemes have adopted the same arrangement for the same reasons. *See, e.g.*, *Review of Energy Independence Act Capacity Contracts*, Docket No. 07-04-24, 2007 Conn. PUC LEXIS 219, at *82-83, *99 (Aug. 22, 2007); *see* discussion of proposed scheme in Maryland, *infra* at 64-66.

While contracts for differences are a common means of coordinating the beneficiary and capacity seller in buyer market power schemes, a net-short requirement that merely attempted to incorporate this type of contract into its definition of "net-short" or "seller" would remain ineffective. The reason is that the arrangements aligning the interests of the beneficiary and the capacity seller need not be contracts for differences, but can take a near-infinite variety of guises. For example, the beneficiary could enter into a derivative transaction that bestows upon the seller a synthetic short position in the capacity market—that is, a contract in which the beneficiary pays the seller an amount that increases as the clearing price in the capacity market drops. This would not be a traditional contract for differences but would serve the same end equally well.

Even an enormously intrusive and administratively infeasible Minimum Offer Price Rule—which examined every single contract, hedge, or other financial position of the capacity seller to determine if it could somehow be part of an indirect arrangement with a net-short participant to suppress capacity prices—still would fail. A party that is net short in the capacity markets, and determined to suppress prices, could just build a new, uneconomical power plant and then sell it in an arm's-length transaction to any willing buyer at an open-market price. The new owner would rationally offer the plant at its going-forward costs, which will be substantially below the cost of new entry, and thereby artificially depress the capacity price. The net-short party that built the uneconomical plant would have received less than it cost to build,[8] but would be more than compensated on a portfolio basis by the price suppression effect. No possible net-short test applied to the new owner—who has no ongoing relationship with the beneficiary, rationally bids the plants into the capacity markets, and need not even be aware of any market-power scheme—could prevent this scheme from succeeding.

d. The Inclusion of Affiliates Fails to Close the Net-Short Loophole

The drafters of the Minimum Offer Price Rule appear to have been aware of the possibilities of the net-short requirement being used as a loophole, and attempted to foreclose such efforts by combining the "Capacity Market Seller *and any Affiliates*" for purposes of calculating the position. Unfortunately, the following tariff definition of "Affiliate" renders this inclusion unhelpful:

> With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

PJM Tariff § 1.0A.01. As demonstrated above, the capacity seller and the beneficiary of the scheme need not have any relationship within this definition of affiliation—or indeed any ongoing relationship at all.

[8] If the net-short party that built the plants could sell them in an arms'-length transaction at a profit, they would by definition not be uneconomical or artificially suppress prices.

In particular, under the New Jersey scheme, none of the relevant actors are likely to be deemed affiliates. The relevant actors are the owners of the new eligible generation (which are obligated to offer the resources into the capacity auctions), the state's electric utilities (which are required to enter into the contracts for differences with the generators), the New Jersey Board of Public Utilities (which arranges for the contracts between the generators and the distribution utilities), and the State of New Jersey (whose bill set up the scheme). None of these are under common control with any of the others (unless they should happen to be so for unrelated reasons). In particular, the electric utilities (which have the net-short positions) and the owners of the new eligible generation (who offer the capacity) are, in a general sense, not under common control, and hence may not be deemed affiliates. Therefore, the electric utilities' net-short position may not be attributed to the owners of the new eligible generation, which would mean that the Minimum Offer Price Rule would never be triggered.

We argue below, in the alternative, that it would be appropriate to permit PJM to treat the electric utilities as affiliated with the owners of the new eligible generation. *See infra* at 73. While such an interpretation may be necessary to thwart attempts to evade the intention of the Minimum Offer Price Rule, this does not detract from the fact that a superior, long-term resolution for this issue is to eliminate the net-short test, mooting any issue regarding the definition of "Affiliate."

e. For These Reasons, the Commission Has Already Excised a Less Demanding Net-Short Requirement in NYISO

The Commission, in its original order approving NYISO's In-City Installed Capacity Offer Floor, had required that only net buyers of capacity be made subject to mitigation. *See N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 100. In response to the objections of NYISO and others, *N.Y. Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 28, the Commission reconsidered and deleted the net-short requirement:

> NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. *We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address*. Parties requesting rehearing have convinced us that defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures. Accordingly, we grant rehearing on this issue[.]

Id. at P 29 (emphasis added). It is the depression of prices, not the mental state of any particular market participant—which may not be discernable in many cases, and will become far less discernable if it became outcome-determinative—that "is the key element that mitigation of uneconomic entry should address." Mitigation should occur whenever uneconomic entry occurs, regardless of intent. *See id.*

The Commission was also persuaded that an effective net-short test was impracticable:

> [NYISO and others] request that the Commission grant rehearing and not limit market power mitigation measures to net-buyers only. Essentially these parties note that the limitation is impractical to implement and would achieve little positive result. They argue that the limitation would give parties an incentive to create companies solely for the purpose of subsidizing uneconomic entry, or that governmental bodies could subsidize uneconomic entry under a public policy rationale. NYISO, in particular, emphasizes that limiting uneconomic entry mitigation measures to net buyers could undermine enforcement because buyers may behave strategically to avoid categorization as net buyers. NYISO also points out that the process for identifying net buyers is unclear and that this could also result in evasion of the mitigation measures. NYISO notes that "net buyer" could be defined a number of different ways, for example, as a single entity or as an entity including all affiliates that serve load. Such a definition would not consider generation affiliates that could construct uneconomic generation and escape mitigation. NYISO also explains that contractual relationships could be undertaken to circumvent mitigation of uneconomic entry and that these would be extremely difficult to identify. … NYISO further emphasizes that if the Commission's view that only "net buyers" have the incentive to engage in uneconomic entry is correct, the "net buyer" condition would be unnecessary since there would be no other sources of uneconomic entry.

Id. at P 28.

Notably, the Commission in *NYISO* pointed to nearly the *exact method* that the New Jersey Law, introduced more than two years later, would use to steer itself through the net-short loophole. *Compare id.* ("For example, … a 'contract for difference' might allow a buyer to subsidize uneconomic entry in a way that would not be apparent to" the administrator of the capacity market.) *with* New Jersey Law at 15 (prescribing a subsidy for each MW of capacity "equal to the difference between the [fixed subsidy price] and the [auction clearing price]").

2. Self-Supply Should Not Be Exempt

The current Minimum Offer Price Rule's self-supply loophole is yet another fatal flaw. Even if mitigation goes into effect, the Minimum Offer Price Rule prescribes a particular order for the assignment of capacity obligations:

(i) first, all Sell Offers in their entirety designated as self-supply;

(ii) then, all Sell Offers of zero, prorating to the extent necessary; and

(iii) then all remaining Sell Offers in order of the lowest price.

RPM § 5.14(h)(4). Under this priority, it appears that Sell Offers designated as self-supply will always be accepted in full, even if the Minimum Offer Price Rule otherwise indicates that they are uncompetitive and ought to be mitigated. The market participants who would benefit from the use of market power to suppress capacity prices—load-serving entities—can also freely designate their capacity resources as self-supply. The priority for self-supply thus effectively eliminates any constraint on the exercise of market power. This defect, standing alone, would be sufficient to render the Minimum Offer Price Rule unjust, unreasonable and unduly discriminatory.

a. A Self-Supply Loophole Is Unnecessary

The basic premise underlying the argument to exempt self-supply from review and mitigation is that self-supply cannot affect the auction clearing price and therefore cannot be a tool of price suppression. This premise is demonstrably false.

The unstated assumption implicit in this argument is that load interests would only add or designate an additional amount of self-supply if simultaneously choosing to add the same amount of load. Given this assumption, it is true that adding 100 MW of additional load, shifting the demand curve to the right by 100 MW, and adding 100 MW of self-supply priced at $0, shifting the supply curve to the right by 100 MW, will not affect the price at the intersection of supply and demand.

The problem with this unstated assumption, and therefore the entire argument, is that it is without basis in the tariff and contradicted by the observed facts. Nothing in the tariff requires load to add self-supply only when it chooses to increase load by the same amount. In fact, load entities could never commit to add self-supply exactly in step with increases in demand, because, with uncommon exceptions, the overall level of demand growth is not within their discretion.[9] Consumers decide independently whether, where and when to increase or decrease their demand, and PJM develops an aggregate load forecast reflecting expected peak loads in future years. Load then must proceed to decide how to meet that consumer-set demand.

Realistically, the choices available to load are quite different than those assumed by self-supply advocates. Any given load entity's overall level of demand is largely fixed. The only choice for load entities is whether to meet that demand through self-supply or by regular

[9] Further, the market rules governing the use of self-supply designations are based on the capacity responsibility or Installed Capacity tags of the load serving entity at the time the self-supply request is made. As a result, self-supply is made based on historic peak load responsibility of the existing customers the entity serves.

procurement in the auctions. Under the current Minimum Offer Price Rule, if a load entity designates 1,000 MW as self-supply, the effect is to pre-clear that 1,000 MW, removing it from the auction and shifting the demand curve to the left by that amount. This will have *exactly* the same effect on price as if the load entity had offered that 1,000 MW into the auction at a price of $0, shifting the supply curve to the right by that amount. Just as 1,000 MW offered into the auction at $0 is an effective tool for artificial price suppression, so too is designating 1,000 MW of capacity as self-supply. The auction price impacts are indistinguishable.

Exempting self-supply would render the Minimum Offer Price Rule a dead letter. Load interests wishing to exercise buyer market power would effortlessly switch from (1) bidding uneconomic resource projects into the market at anti-competitive prices to (2) designating them as self-supply. Either approach creates exactly the same price-suppression effects.

The fact that self-supply is only possible up to the level of load served by the entity is not to the contrary. A load entity is unlikely to spend more money to self-supply *all* of its requirements. It is, instead, likely to pursue a strategy of self-supplying only a *portion* of its requirements, up to the point that it suppresses the auction sufficiently to create net benefits for the rest of its portfolio. And the load entities serving the largest amounts of demand have the most powerful incentive to artificially suppress capacity prices.[10] Hence, this limit on self-supply would not bind the very entities to whom artificial price suppression is most attractive.

b. Efficient Self-Supply Benefits from Effective Mitigation

An effective Minimum Offer Price Rule without a self-supply loophole would be a benefit, not a harm, to efficient self-supply. A competitive, un-manipulated capacity price—such

10 The fact that some LSEs contract away their load responsibility to competitive market participants is not to the contrary. This current practice, and whatever state laws underlie it, would easily be changed once self-supply becomes the most effective loophole in the Minimum Offer Price Rule.

as would exist under an effective Minimum Offer Price Rule—reveals useful information to all market participants. This price information is particularly valuable for market participants that, for whatever reason, prefer to fulfill their capacity obligations through self-supply or bilateral arrangements outside the auction process.

Inefficient new self-supply—self-supply with costs above the mitigated clearing price—would be affected by mitigation. But outside of a price suppression goal, it is unclear why anyone would be eager to engage in inefficient new self-supply. Inefficient new self-supply, by definition, costs more than the auction clearing price. So any entity that uses inefficient self-supply *must* incur higher costs than if it had just relied upon the market to serve its needs.

c. Load Entities Committed to Self-Supply for Legitimate Reasons Retain the Fixed Resource Requirement Alternative

Schedule 8.1 of PJM's Reliability Assurance Agreement permits parties to satisfy their capacity obligations outside of RPM. A party that chooses the Fixed Resource Requirement Alternative (or FRR Party), submits an FRR Capacity Plan, "a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of [the] Party." RAA §§ 1.25, 1.29. The area covered by such a plan is:

> … (a) the service territory of an IOU …; (b) the service area of a Public Power Entity or Electric Cooperative …; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, …; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area[.]

RAA § 1.31. A FRR Entity meets all its capacity "obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan and meeting all other terms and conditions of such alternative" and need not acquire any capacity in the RPM auctions. RAA § 7.4.

Effectively, FRR Entities exempt themselves from the Minimum Offer Price Rule and fulfill all of their capacity obligations by self-supply. Because FRR Parties are outside the purview of the Minimum Offer Price Rule, they remain free to make arrangements for capacity at any terms otherwise lawful, including at prices above the RPM clearing price, should they so choose. The availability of this option and its obvious attractiveness to the load parties who have chosen it, *see, e.g.*, PJM, *2013/2014 RPM Base Residual Auction Planning Period Parameters* at 2, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx (showing that about one seventh of PJM's entire capacity obligation is met through FRR plans), even under the current ineffectual Minimum Offer Price Rule, should be a sufficient answer to any cavil that RPM with the Revised Minimum Offer Price Rule would be unduly harsh and intrusive to parties seeking to self-supply.

The only self-suppliers who would raise issue with the elimination of the Minimum Offer Price Rule's self-supply loophole are those that insist on only *partially* self-supplying—those who seek to be free to suppress RPM capacity prices through their self supply, *and* wish to remain eligible to profit from the price suppression by covering the remainder of their capacity obligations at the prices they artificially suppressed. But no market participant can demand a right both to move prices *and* to profit thereby. The elimination of the Minimum Offer Price Rule's self-supply loophole, in combination with the available FRR alternative, would only prevent load entities from having it both ways.

d. The Commission Approved the Minimum Offer Price Rule Expressly in Order to Mitigate Self-Supply

Perhaps the most remarkable feature of the current Minimum Offer Price Rule's self-supply exemption is that it is directly contrary to the findings of the Commission approving the

Minimum Offer Price Rule. In its order, the Commission justified the Minimum Offer Price Rule on the basis of:

> the concern that net buyers might have an incentive to depress market clearing prices by offering some *self-supply at less than a competitive level*. … 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*.

PJM Interconnection, 117 FERC ¶ 61,331 at PP 103-04 (emphasis added). It is impossible to reconcile this justification with the language of the current Minimum Offer Price Rule, which gives priority "first, [to] all Sell Offers in their entirety designated as self-supply" regardless of mitigated price and ahead of all priced (or substitute priced) Sell Offers.

According to the Commission's order, the purpose of the Minimum Offer Price Rule is to mitigate the exercise of market power through self supply. But according to its text, the Minimum Offer Price Rule appears to completely exempt self supply. The Tariff should be conformed to the Commission's order. Our proposed Minimum Offer Price Rule does so. *See* Revised MOPR (5).

3. State-Sponsored Projects Should Not Be Exempt

The Minimum Offer Price Rule improperly exempts certain state-sponsored projects:

> [A]ny Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

RPM § 5.14(h)(1)(iv). This state sponsorship exemption is unnecessary and harmful, and should be deleted.

It requires little prescience to expect an attempt by the states to use this loophole to shield schemes to exercise buyer market power. A mere evidentiary hearing giving PJM a chance to be heard—all that is currently required under the current tariff—would be unlikely to impede state-sponsored price-suppressing entry. The Commission should eliminate this unnecessary loophole. And as discussed below, *see infra* at 67-69, closing this loophole in no way infringes on the legitimate power of the states.

4. *The Commission Should Remove the Tariff Language Limiting Mitigation to "Planned Generation Capacity Resources"*

As we established above at 25, because the current tariff limits mitigation to "Planned Generation Capacity Resources," it necessarily imposes a one-year limit on the duration of mitigation. After the first auction, a planned resource will no longer be "planned"—it will be existing, and exempt from all mitigation. As we also established above, this is unjust and unreasonable. Mitigation should extend until a resource proves it is economic by clearing in two auctions.

In order to implement this badly needed fix to the mitigation scheme, it obviously is necessary to delete the language in the tariff limiting mitigation to "Planned Generation Capacity Resources."

C. *Deferred Issues*

We propose deferred treatment of the following issues:

1. *Long-Lead-Time Resources Should Not Be Exempt, But Should Be Subject to a Slightly Different Mitigation Process*

Currently the tariff exempts long-lead-time resources from mitigation. There is no justification for this exemption. These resources can achieve artificial price suppression just as readily as resources that can be developed within the three-year lead-time period built into the RPM auction process. We thus propose to close this loophole.

That said, there is one unique consideration posed by long-lead-time units that merits a narrow but important change in the mitigation scheme we propose. As noted above, all resources have the option of satisfying the conduct screen by showing that their offer is cost-justified. For long-lead-time resources, this showing should be made very early in the process. These resources, typically baseload facilities like coal and nuclear, take many years to build—longer than the Base Residual Auction's three-year forward horizon. On the other hand, short-lead-time units, like combustion turbines, can easily be built within three years.

This has implications for the proper structure of the mitigation process. As Dr. Shanker explains:

> For longer-lead-time units, it is important that market participants not be caught in a situation of having made a rational business decision at the time of commitment to essentially begin construction, only to subsequently find themselves subject to mitigation. This could happen if circumstances changed between the time of commitment and the first eligible Base Residual Auction.

Shanker at 44:17-21. But:

> For shorter-lead-time units, this concern can effectively be ignored. Mitigation can instead be focused on behavior in the Base Residual Auction because the shorter-lead-time unit can be built within the three-year window between the auction and delivery. Offers will be mitigated if they are uneconomic, but the project will know before construction begins whether it will be subject to the mitigation of its Sell Offer in the capacity market auctions. Further, any project (long- or short-lead-time) that can demonstrate it has not received discriminatory benefits will be free from all mitigation. This allows market participants with legitimate, unsubsidized short-term projects to exercise their own private business decision-making, independent of the expectations of PJM or the Independent Market Monitor.

Id. at 45:2-11.

Long-lead-time resources thus should be exempt from mitigation if they can prove themselves economic early in their development, even if capacity prices move down later. *See* Revised MOPR (3)(iv). This offers long-lead-time units the flexibility to learn their mitigation status at an earlier point in time, when fewer costs have been incurred, thus increasing regulatory certainty. It is also consistent with the mitigation regime in NYISO. *See* Shanker at 45:19–50:8. This issue can be deferred, however, since, by definition, no such resources will be emerging anew in the short time frame presented by the May 2011 auction.

2. *Demand Response Resources Should Not Be Exempt*

In our view, there is no principled reason to exempt all demand response resources from mitigation. Demand response resources can just as readily be used to artificially suppress prices as generation resources, and, in fact, have been used for that purpose. *See infra* at 64. Mitigation appropriate to Generation Capacity Resources also is appropriate to demand response resources.

3. *Renewable Resources Should Not Be Exempt*

The same outcome is appropriate for renewable resources. These resources typically do not have high capacity values. But they nonetheless can create artificial price suppression. And they already are covered by the existing buyer mitigation regime. That coverage should continue. But we agree that this question should be addressed in the deferred stage of the case.

4. *Uprates to Existing Units Should Not Be Exempt*

Uprates to existing units also should be mitigated. The same logic that only excuses the cleared portion of a unit from future mitigation (*see supra* at 38), also requires the elimination of the blanket mitigation exemption for "any upgrade or addition to an existing Generation Capacity Resource." In the above example, only the 200 MW of the 500-MW resource become exempt from mitigation, the other 300 MW still must clear at least once. Any uprate or additional capacity to an existing resource will not previously have cleared in a capacity auction. There is no economic or legal justification for giving different treatment to (1) a 500-MW resource, of which 200 MW have cleared and 300 MW have not, and (2) a 200-MW resource that has cleared in full and that then undergoes a 300-MW uprate. Consistency requires that the 300-MW uprate must clear at least once on the basis of an appropriate, incremental measure of cost before it becomes exempt from mitigation.

IV. RPM FACES IMMINENT THREATS

The remedies that we propose above should be accepted to close loopholes in the current Minimum Offer Price Rule. We request fast track relief, however, to ensure that the rules will unambiguously prevent uneconomic entry of the kind that the New Jersey Law is designed to create.

A. The States Have Shown That They Are Ready, Willing and Able to Exercise Buyer Market Power

The states have been the greatest advocates for using the unmitigated exercise of buyer market power to suppress prices in the Commission-jurisdictional wholesale capacity markets. While not the only example, the New Jersey Law referred to above is a prototypical example.

1. The New Jersey Scheme Is a Textbook Exercise of Buyer Market Power

a. Overview

The New Jersey Law is a classic example of a market power scheme. It exhibits, in distilled form, both principal components. *First*, the scheme requires the state to subsidize, for up to 15 years, new capacity resources at a price substantially above any plausible express or implicit estimate of auction price outcomes. In fact, the New Jersey hearings failed to engage in a stand-alone evaluation of costs, and instead proceeded solely on representations of "savings" associated with the price suppression associated with the exercise of market power. *Second*, the scheme can be expected to substantially and artificially depress capacity market prices via the out of market support of uneconomic new entry. This price effect renders the entire scheme, including its uneconomic component, profitable overall in the short run. *See* Shanker at 38:4-39:14.

In sum, the New Jersey Law is no different than any other attempt to use market power to shift prices—including through economic withholding, which the Commission routinely interdicts, investigates, and prosecutes. And yet, thanks to the flaws afflicting the Minimum Offer Price Rule set forth above, *see supra* at 18-57, it remains possible that the New Jersey scheme may escape mitigation completely. The Commission should act forcefully to protect its jurisdictional markets and to remove any confusion.

At the core of the New Jersey Law, are Standard Offer Capacity Agreements—styled as the Long-Term Capacity Agreement Pilot Program—to be entered into by eligible generators and the state's electric public utilities, under the supervision of the New Jersey Board of Public Utilities. New Jersey Law at 18. Under the legislation, the state's "electric public utilities shall procure 2,000 megawatts of financially-settled [Standard Offer Capacity Agreements] from eligible generators." *Id.*

An eligible generator that enters into a Standard Offer Capacity Agreement obligates itself to build a "base load or mid-merit electric power generation facility." *Id.* at 8. *Only* new resources "that commence[] construction after the effective date of the" New Jersey Law are eligible. *Id.* at 9. The New Jersey Board of Public Utilities (and its agent) get to decide the price and quantity of capacity eligible generators have to offer into the RPM auction. *See id.* at 18-19. If there was any question about how the Board will exercise this discretion, it is removed by the requirement that "eligible generators … participate in and *clear* the annual base residual auction." *Id.* at 20 (emphasis added). The only way an eligible generator could commit itself to clear the capacity auction is by bidding below competitive levels, or even as a complete price taker (at $0/MW-day).

The compensation scheme under the statute is a straight "contract for differences." The Board is ordered to:

> establish a method and the contract terms for providing for selected eligible generators to receive payments from the electric public utilities for the difference

> between the [contract price] and the [clearing price] multiplied by the [Standard Offer Capacity Agreement] capacity in the event the [contract price] is greater than the [clearing price] for any applicable delivery year and for providing for electric public utilities to receive refunds from the selected eligible generators for the difference between the [contract price] and the [clearing price] multiplied by the [contract price] capacity in the event the [clearing price] is greater than the [contract price] for any applicable delivery year;

Id. at 19. New Jersey ratepayers are the funding source for this subsidy:

> The board shall order the full recovery of all costs associated with the electric public utilities' resulting [Standard Offer Capacity Agreements] … from ratepayers through a non-bypassable, irrevocable charge.

Id. at 20.

b. *The New Jersey Scheme Requires Conduct That Is Not Economically Rational on a Stand-Alone Basis*

The net effect of these payments and remittances is to transfer all exposure to RPM capacity clearing price from the eligible generator to the state's electric public utilities—and ultimately from consumers. If the clearing price falls below the contract price, ratepayers will make the eligible generator whole, up to the contract price. If the auction clearing price rises above the contract price, the electric public utilities will reclaim all excess revenues. The selected eligible generators will charge the state's electric public utilities for the plant's capacity at the fixed contract price set by the state, not the price resulting from the RPM auction. In addition, the eligible generators have given up not only the economic interest in their plants' capacity, but also any discretion about how to bid the capacity into RPM; they are required to offer capacity as instructed by the state.

Finally, under this scheme, having purchased the capacity at a fixed contract price, the state turns around and offers it, via proxy, into RPM at uncompetitively low levels that are sure to clear the market. This is not the conduct of an economically rational, competitive participant in a single-clearing-price auction. An economically rational participant would offer a resource into the auction at the marginal cost the participant would have to bear to acquire the resource. If the auction clearing price rises above that offer price, the resource clears and the participant stands to profit from the excess of the clearing price over its cost. If the auction clearing price drops below that offer price, the resource does not clear and the participant avoids taking a loss.

c. New Jersey Nevertheless Intends to Profit on a Portfolio Basis From the Scheme Through Its Price Impact

While facially uneconomic, the state's conduct in RPM is readily explained as an attempt to exercise buyer market power. Unless this exercise of market power is mitigated, the state's expected losses on the Standard Offer Capacity Agreements will be more than offset by its savings on the remainder of the state's portfolio of capacity obligations.

(i) Drafts of the New Jersey Law Repeatedly Suggest That the Purpose of the Scheme Is the Suppression of Capacity Prices

Although the most recent versions of the New Jersey Law have been scrubbed of most references to capacity price levels, earlier public drafts were less discreet. A draft identified the problem to be addressed that RPM, "as estimated by the [New Jersey Board] of Public Utilities, costs New Jersey ratepayers an additional $1 billion per year for capacity." New Jersey Law, Introduced Version § 1.a (Oct. 18, 2010). The stated purpose of the bill was to "alleviate the cost burden" of RPM. *Id.* § 1.d. "[T]o avoid higher electricity prices" was declared State policy. *Id.*

These statements highlight the fact that the state is deliberately seeking to artificially suppress capacity price outcomes committed to the exclusive jurisdiction of the Commission. That the sponsors of the New Jersey Law saw wisdom in amending the bill to remove the above-quoted statements of intent from the draft strongly suggests that they too have belatedly become aware of the dubious legal ground underlying the legislation.

(ii) New Jersey Hearing Testimony, and Subsequent Statements, Also Show That the Law Is Designed to Suppress Capacity Prices

While the text of the New Jersey Law has become less forthcoming about the motives and expectations of its backers, witnesses in favor of the bill, called by the state's legislative committees and their allies, have remained frank.

Take, for example, the Director of New Jersey's Division of Rate Counsel, a state agency tasked with "represent[ing] and protect[ing] [load-side] interest." Stefanie A. Brand, Remarks Regarding A3442, Presented at the Assembly Telecommunications and Utilities Committee Meeting (Dec. 16, 2010), http://www.state.nj.us/rpa/docs/Remarks_of_Stefanie_Brand_A3442-Electric_Generation_Facilities.pdf. She testified as follows:

> With the guarantee, these companies can get financing to build their plants. Ratepayers don't pay anything *unless we succeed in reducing the capacity prices* below the figure set in the Agreement, at which point we would pay the difference between the lower price and the set price. If that happens, it would mean that *we have been successful and that we will be saving more overall than we would be paying to these plants.*

Id. (emphasis added).

And according to the press, a spokesperson for one of the generators expecting to be sponsored under the New Jersey Law responded as follows to criticism that it represented a subsidy to the generator:

> [He] said the payment is fully recovered in savings ratepayers will see because of a lower capacity price. "If the price goes down to $200, there is a savings, that means the entire capacity market clearing price has also gone down, which means the ratepayers are now saving money relative to if that plant had not been in that market, in that auction for that particular year," he said.

Kelly Harrington, *N.J. Senate Clears in-State Generation Bill* (Nov. 29, 2010). The spokesman for one of the New Jersey Law's sponsors in the state Assembly was equally blunt: "Consumers have been paying inflated capacity charges[.] … This is a chance to reverse that. How can that not be a good thing for consumers?" Andrew Maykuth, *Veto urged for N.J. power-plant bill*, Philadelphia Inquirer, Jan. 13, 2011, http://www.philly.com/inquirer/business/20110113_Veto_urged_for_N_J__power-plant_bill.html.

Any claims that the purpose of the New Jersey Law is to address "projected capacity deficiencies in New Jersey," New Jersey Law § 1.b, or "reliability concerns," New Jersey Law § 1.e, or that it "ensure[] sufficient generation is available to the region, and thus the users in the State, in a timely and orderly manner," New Jersey Law § 1.d, contradicts arguments that the New Jersey Board of Public Utilities—one of the principal proponents of the New Jersey scheme—and the Maryland Public Service Commission—the sponsor of the Maryland scheme, have made to *this* Commission, *see supra* at 10-11 (and the testimony there cited). When attacking the creation of RPM, these parties, far from expressing any concerns that RPM might procure insufficient amounts of capacity for reliability, argued the opposite, that RPM was designed to systematically *over-procure* more capacity than necessary to ensure reliability. *See, e.g.*, *Md. Pub. Util. Comm'n v. PJM Interconnection*, Docket No. EL08-67-000, Complaint at 57 (May 30, 2008) ("PJM's methods for calculating capacity needs are overly conservative"); *id.* ("An Excess Capacity Requirement Is Built Into The VRR Curve."); *id.* ("PJM Overestimated Peak Load."); *id.* at 58 ("PJM Used An Unreasonable [High] Reliability Standard For" Locational Deliverability Areas). Nor was this a generalized or theoretical complaint. New Jersey and Maryland specifically denounced the reserve requirements within their own areas as grossly excessive. *Id.* at 58-60. These parties should not now be heard to argue that they are forced to supplement RPM because it just does not procure enough capacity to ensure reliability.

In light of the fact that there is no requirement in either the drafts or the passed version of the bill that the sponsored resources need to be renewable or otherwise environmentally friendly, any claims that the purpose of the New Jersey Law was to address environmental concerns would be similarly hard to credit. *See* New Jersey Law, Introduced Version § 3 (Oct. 18, 2010) (declaring any "natural gas fired, combined-cycle" facility eligible); New Jersey Law, Final Version § 3 (making any "base load or mid-merit electric power generation facility" eligible).

Nor is the New Jersey scheme likely to be contained to a limited quantity of subsidized resources. As the principal sponsor of the New Jersey scheme in the State Assembly recently noted, "the bill was expanded Thursday to 2,000 MW because Governor Christie wanted to make sure other regions in the state also have the opportunity to get new plants. 'It's politics,' he said." Mary Powers, *N.J. legislation would subsidize 2,000 MW*, Platt's Megawatt Daily, Jan. 10, 2011, at 14; *see also* Market Monitor Maryland Report at 4 (summarizing impact of double-sized New Jersey Law and the Maryland RFP).

(iii) New Jersey's Scheme Is Likely to Be Highly Profitable to Its Sponsors in the Short Run

Beyond the implications of New Jersey's own statements, and the parallels to the actions of other states, one overarching economic fact powerfully points to the conclusion that New Jersey intends to profit from its scheme by suppressing capacity prices: the scheme as proposed can be expected to succeed at dramatically moving capacity price in New Jersey's favor. As PJM's independent market monitor, Dr. Bowring, testified:

> Our analysis indicates that adding 1,000 MW of capacity in New Jersey, paying it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 600 million dollars in EMAAC and about 400 million dollars in MAAC. The reduction in capacity payments to suppliers in New Jersey would be about 280 million dollars.

Dr. Joseph E. Bowring, Testimony of to New Jersey Assembly re: Assembly Bill No. 3442 (Dec. 16, 2010) ("Bowring Testimony"), http://www.monitoringanalytics.com/reports/Reports/2010/Bowring_NJ_Assembly_3442_Testimony_20121216.pdf.

Dr. Bowring testified with respect to the 1,000 MWs of capacity originally authorized by the New Jersey Law. Subsequent analysis by Dr. Bowring based on the full 2,000 MW of additional sponsored capacity increased the first-year estimate of the price impact of the New Jersey scheme to $2 billion. *See* Market Monitor Maryland Report at 4. After the New Jersey Law was signed, a spokesman for the state's governor endorsed this analysis. Naureen S. Malik, *New Jersey Passes Law to Build New Gas-Fired Power Plants*, Dow Jones Newswires, Feb. 1, 2011 (quoting Michael Drewniak, spokesman for Gov. Chris Christie, as saying "The new generation could cut $2 billion in annual PJM capacity payments.").

The text of the New Jersey Law confirms that its sponsors too are quite aware of this opportunity to profit from the exercise of market power. The New Jersey Law orders the Board of Public Utilities to "select[] [the] of winning eligible generators based on the *net benefit* to ratepayers." New Jersey Law at 18 (emphasis added); *see also* New Jersey Law at 19 (ordering the board to "establish a method for evaluating and comparing the net value to ratepayers of each eligible generator's offer price and term"). The subsidy to the sponsored new entrants can only be a cost to ratepayers. The only way for the state to profit from the scheme, and thereby realize a *net benefit*, is by suppressing capacity prices. The reference to net benefits thus tacitly admits the intent of the legislation.

2. Maryland Is Initiating a Similar Market Power Scheme of Its Own

In addition, Maryland recently has embarked on a similar scheme. The Maryland Public Service Commission in its most recent Draft Request for Proposal for New Generating Facilities summarized its scheme as follows:

> The [Maryland Public Service] Commission is requesting proposals for Products, which must include Capacity, Energy and any available Ancillary Services and which may include Maryland Tier 1 RECs. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located in or around Maryland so long as such Generation Capacity Resource is

interconnected to the System such that the Generation Capacity Resource's output is infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion.

Maryland RFP at 3.

In all essentials, the Maryland scheme is identical to the New Jersey scheme. Maryland, like New Jersey, seeks to suppress RPM capacity prices by sponsoring new entrants through unduly discriminatory new contracts for differences:

(a) Only new resources are permitted to participate. *See id.* at 4 ("Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM capacity auction").

(b) The method by which these new resources are subsidized is a contract for differences. *Id.* ("The financial arrangement between the Buyer and a Supplier for Capacity, Energy and Ancillary Services will be a Contract-for-Differences (CfD)").

(c) The sources of the subsidy are the local electric distribution companies and their ratepayers. *See id.* at 5 ("For the Supplier's Capacity and Energy, the financial arrangement between the [electric distribution company] and the Supplier will be a CfD between a) the Supplier's contract Capacity price and the RPM Locational Deliverability Area clearing price applicable to the Maryland [electric distribution company]'s service territory, and between b) the Supplier's contract Energy price and the hourly PJM nodal Locational Marginal Pricing (LMP) in the PJM DAM and/or RTM, as applicable, at the point of delivery into the [electric distribution company's] service territory.").

(d) New resources are to be injected into the capacity auctions as rapidly as possible. *See id.* at 3 ("Generation Capacity Resources that can achieve a Commercial Operation Date (COD) on or around June 1, 2015 will be favored in this solicitation.").

(e) Conventional resources are permitted to participate in the Maryland scheme, defeating any suggestion that environmental concerns are at its root. *See id.* ("Generation Capacity Resources may be conventional or renewable generation technology").

(f) The Maryland Public Service Commission claims that the purpose of the Maryland scheme is to protect reliability. *Id.* at 1 ("The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers."); *id.* at 2 (justifying scheme on the basis that "Maryland law directs this [Maryland Public Service] Commission to ensure an adequate and reliable supply of electricity to Maryland citizens."). These claims, just as New Jersey's parallel claims, are in direct contradiction to the Maryland Public Service Commission's statements to the Commission. *See supra* at 62.

(g) The capacity from the new resources must be offered not at the competitive price, but at a price that guarantees that the resources will be obligated in the RPM and therefore impact the clearing price. *See id.* at 5 ("The Supplier must offer such Capacity into the PJM BRA so that it will clear and be committed, subject to the direction and timely notification of the [Maryland Public Service] Commission").

In fact, the New Jersey and Maryland schemes are so close to being carbon copies that it is shorter to list their substantive differences:

(a) The Maryland scheme covers up to 1,800 MW, compared to 2,000 MW for the New Jersey scheme. *See id.* at 4 ("The Commission may award one or more contracts to one or more Suppliers for Products derived from Generation Capacity Resources or may direct one or more [electric distribution companies] to construct new generation up to, but not to exceed, a total installed capacity of 1,800 MW.").

(b) The Maryland scheme requires participants to turn over all of their economic interest in not only the capacity markets, but also the energy markets via additional contract-for-differences payments. *See id.* at 5.

Neither of these details has any impact on the analysis of the scheme's purpose and impact in the capacity markets.

Finally, the admitted core purpose of the Maryland scheme is the same as that of the New Jersey scheme: to recoup the subsidy expense and reap profits on a portfolio basis from the artificially depressed capacity market prices. The Maryland proposal, while not quite as blatant as the draft New Jersey Law, still makes this purpose entirely clear by stating that proposals will be evaluated on the basis of "the impact of different Generation Capacity Resource portfolios on the *expected net benefits* realized by" Maryland. *Id.* at 16 (emphasis added). For there to be a expected *net benefit*, Maryland can only be counting on its portfolio profit from suppressed capacity market prices. In specifying this net-benefits criterium as the standard against which it will judge proposals, Maryland tacitly admits that it is engaged in artificial price suppression, that is, the exercise of market power.

3. *Nothing in the Revised Minimum Offer Price Rule Stands in the Way of New Jersey, Maryland or Any Other PJM State Enacting Policies Within Its Domain*

We expect that our opponents will claim that a strengthened Minimum Offer Price Rule will interfere with states' rights to formulate and implement policy about when and where to build generation, and what generation to build. This is a red herring.

Our proposed Minimum Offer Price Rule, just like the current Minimum Offer Price Rule, imposes *no requirements whatsoever* on states with respect to their local power supply policy. With or without the Minimum Offer Price Rule, states remain free to permit or not to permit new generation, or to choose some particular type of facility to further other state policy objectives (such as limiting greenhouse gas emissions). They also remain free to establish any local reliability or additional adequacy requirements they wish. Nothing in any Minimum Offer Price Rule under consideration will in any way threaten state action on these matters.

The sole effect of a Minimum Offer Price Rule is on the *price* of capacity—a matter undisputedly within the Commission's exclusive jurisdiction. Any attempt to argue that the Minimum Offer Price Rule somehow invades the proper province of state regulation runs head-long into binding precedent to the contrary. As the D.C. Circuit has ruled:

> Of course, it is a basic principle of economics that prices affect supply—the auction clearing prices in each sub-region of New England will certainly influence the amount of capacity that generators are willing to supply. Indeed, one of the primary purposes of the new market mechanism is to provide incentives to attract new infrastructure where needed. But an incentive is not a mandate. The mere fact that the Forward Market will encourage new supply does not mean that it *regulates* facilities used for the generation of electric energy. Rather, the Forward Market is designed to address pricing issues, which fall comfortably within FERC's statutory authority over the sale of electric energy at wholesale in interstate commerce.

Me. Pub. Utils. Comm'n v. FERC, 520 F.3d 464, 479 (D.C. Cir. 2008) (internal citations and alterations omitted) (generally upholding *Devon Power*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133; *ISO New England*, 117 FERC ¶ 61,132 (2006), *reh'g denied*, 119 FERC ¶ 61,044 (2007)), *rev'd in part on other grounds sub nom. NRG Power Mktg. v. Me. Pub. Utils. Comm'n*, 130 S. Ct. 693, *remanded by Me. Pub. Utils. Comm'n v. FERC*, 625 F.3d 754 (D.C. Cir. 2010).

The Commission similarly considered and rejected this same argument when used to attack NYISO's buyer mitigation rules:

> Because uneconomic entry could produce unjust and unreasonable capacity prices by artificially depressing those prices, and NYISO's proposal provides a reasonable means to deter uneconomic entry in the in-City market, we deny NYPSC's request that the Commission reject the proposed minimum bid requirements for new capacity suppliers. Contrary to NYPSC's claim, we find that granting its request would adversely impact matters within the Commission's jurisdiction—in particular, the establishment of just and reasonable wholesale electric energy rates. Adoption of NYPSC's proposal would lead to artificially depressed capacity prices, thus both causing existing generators to be under-compensated and also directly and adversely impacting the Commission's ability to set just and reasonable rates for capacity sales in the in-City market. …
>
> The NYISO's offer floor proposal is an integral part of NYISO's proposal, which the Commission is adopting, needed to "promote long-term reliability while neither over-compensating nor under-compensating generators." The issue before us in this proceeding is not how to meet the resource adequacy requirements of New York State, but how prices for capacity in the wholesale markets should be determined in order to remedy identified flaws in the ICAP market. As we have found previously, issues of resource adequacy are important to the Commission in meeting our statutory mandate under the [Federal Power Act] to ensure that the rates, terms and conditions of jurisdictional transmission and sales of electric energy are just, reasonable, and not unduly discriminatory, or preferential.
>
> Further, we find that our action in approving NYISO's minimum bid proposal does not adversely affect NYPSC's regulation of resource adequacy in NYC. This new pricing methodology does not prescribe whether or what types of generation facilities should be built, contrary to NYPSC's concerns.

New York Ind. Sys. Operator, 122 FERC ¶ 61,211 at PP 110-12 (citations omitted).

In sum, the sole effect of our proposed Minimum Offer Price Rule would be to reduce the risk that uneconomic entry would distort the competitive price levels in the PJM capacity markets. If that is no part of the uneconomic entry sponsors' intent, an effective Minimum Offer Price Rule will not deter their behavior. If distorting the PJM capacity markets *is* the intent, then the Commission is statutorily *required* to thwart such conduct and protect competitive wholesale power prices. States retain the power to pursue whatever lawful initiatives they wish, so long as they, not the market, pay the cost of the consequences of uneconomic designs. If they chose to bear these costs themselves, without distorting prices under the Commission's jurisdiction, they can do so. But they are not entitled to distort prices in the Commission's jurisdictional markets.

B. Fast Track Relief Is Essential

The next RPM auction is scheduled for May 2011. Given the imminent threats that the auction results will be affected by the exercise of market power, fast track relief is required.

The issues raised herein call for an expeditious resolution or, at least, a clarification that any action undertaken by a market participant, such as the execution of the New Jersey scheme, will not be deemed to have created facts that the Commission would be compelled to accept as *fait accompli* in any subsequent resolution.

The sponsors of the New Jersey scheme, seeking to exploit the flaws of the Minimum Offer Price Rule, PJM RPM § 5.14(h), show great concern with speed. *See, e.g.*, *N.J. Senate Rushing Bill to Build New Power Plant*, pressofAtlanticCity.com, (Dec. 12, 2010, 1:00 PM), http://www.pressofatlanticcity.com/business/article_b5004b6f-38d1-5971-9d94-05786c6186f6.html (updated Dec. 13, 2010, 10:04 AM). The bill was introduced into the state senate on October 18, 2010 and the state assembly on October 25 and was immediately referred to the relevant committees, was passed by the legislature on January 10 and was signed by the governor on January 28. *See* New Jersey Law, Introduced Version (Oct. 18, 2010); Assemb. No. 3442, 214th Leg. (Oct. 25, 2010); Press Release, Office of the Governor of New Jersey, Governor Chris Christie Takes Action on Legislation (Jan. 31, 2011), http://www.state.nj.us/governor/news/news/552011/approved/20110131b.html. The bill waives "any provisions of the [state] Administrative Procedures Act" and sets a rapid schedule for completion:

> The board shall initiate and allow such proceeding to be completed no later than 60 days after the effective date of [the New Jersey Law] to allow for the commencement of the [New Jersey scheme]. The [contracts] resulting from that proceeding shall be awarded and executed no later than 30 days after the approval of the form of the [contracts].

New Jersey Law at 17. This schedule is designed to permit the new sponsored resources to participate in the May 2011 Base Residual Auction. That this is the aim of the sponsors is confirmed by the instruction that "generators that can enter commercial operation for delivery year [2014/15] are to be provided with a weighted preference." New Jersey Law at 18.

The clear implication is that the sponsors of the New Jersey scheme either deliberately seek to deny the Commission any opportunity to act in a timely manner, or at the very least deem the absence of Commission review desirable.[11] This is unsurprising. The sponsors of the scheme may very well hope that by acting before the Commission can react, they will be able to cram their resources into the upcoming Base Residual Auction unimpeded. If—thanks to the inadequate Minimum Offer Price Rule—these resources then clear in the auction, their sponsors undoubtedly will argue that any revisions to the tariff subsequently approved by the Commission cannot be applied to these resources, given the injunction against retroactive ratemaking and concern about the preservation of settled expectations. *Cf. N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 118 (exempting existing units from mitigation because deterrence of uneconomic entry is "by definition, is no longer possible").

The Commission should interdict such efforts to avoid its jurisdiction and statutory mandate to ensure just, reasonable and non-discriminatory price outcomes in competitive markets:

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[11] That the New Jersey Law contains a provision, added at the last minute, to permit the New Jersey Board of Public Utilities to suspend any provisions which are legally challenged, *id.* at 21, should offer little comfort. This suspension is purely within the discretion of the Board and, given that body's stated preferences, unlikely to be exercised.

First, as we note below, *see infra* at 75, the present complaint is eminently well-suited for fast-track processing: the facts are not in dispute and the law and economics are unambiguous. Moreover, we have acted expeditiously in order to preserve the Commission's authority by preparing for litigation as soon as the New Jersey scheme became public knowledge and filing this complaint within days of the New Jersey Law's enactment. Furthermore, in order to reach a concrete solution as quickly as reasonably practical, we have also taken the uncommon step of proposing concrete revised tariff language in this initial complaint. As a consequence, the Commission is in a position to rule on this complaint in time for the May 2011 Base Residual Auction. We urge the Commission to do so.

Second, even if the Commission were unable to issue a ruling on the matters presented here before the next Base Residual Auction, this complaint gives notice that the legality of the New Jersey Law is very much in doubt. This awareness precludes any settled expectation that any resources used in the scheme will be shielded from future corrections to the PJM tariff ordered by the Commission. The filing of this complaint also establishes a refund effective date, *see infra* at 76, far in advance of the May 2011 Base Residual Auction.

Third, even if the Commission were unable to issue a ruling before the next Base Residual Auction and the charges arising out of that auction were deemed final and not subject to refund, this would not bar mitigation of the New Jersey scheme resources in future Base Residual Auctions. As the Commission ruled in the context of RPM, and at the urging of the Maryland Public Service Commission, even an exemption from mitigation expressly granted by the Commission remains subject to later rescission and prospective mitigation. *See Md. Pub. Serv. Comm'n v. PJM Interconnection*, 123 FERC ¶ 61,169, *reh'g denied* 125 FERC ¶ 61,340 (2008).

> We find that imposition of mitigation on the previously exempt units is appropriate because we find the existing standard for whether to mitigate these particular units is no longer just and reasonable. … Rather than having PJM establish an entirely new market power standard for [the previously expressly exempt] generators, we find that PJM should apply the same market power test to these generators as to all other generation. In sum, we find that the uncertainty and difficulty inherent in the administration of the currently effective "significant" market power standard can result in rates that are unjust and unreasonable and that this standard should be replaced with the standard used by PJM for assessing market power for all generators.

123 FERC ¶ 61,169 at P 43. If an RPM mitigation exemption expressly granted to certain generation resources and approved by the Commission can subsequently be rescinded, any New Jersey scheme resources that slipped through the Minimum Offer Price Rule loopholes—before they could be closed—can and should be subjected to mitigation in future auctions. The revised Minimum Offer Price Rule proposed herein is designed to "recapture" any resources that slipped through these loopholes. Any resources that were part of a market power scheme subsequently recognized by the Commission would be subject to mitigation from the time of recognition until they pass the market test establishing that they would have been created on the basis of their true, economic costs. *See supra* at 37.

Nevertheless, and for the foregoing reasons, an expeditious resolution of the issues raised in this Complaint is both feasible and highly desirable. We believe that the Commission will have sufficient time to fully consider the merits of the issue and order appropriate tariff changes before the next Base Residual Auction in May 2011. However, if the Commission should conclude that the complexities of the Revised Minimum Offer Price Rule proposed herein require more extensive Commission consideration, we urge the Commission to issue a stop-gap measure to prevent RPM from collapsing in the interim. In particular, one possibly effective stop-gap would be to apply a 100% benchmark to all offers from new combustion turbine and combined cycle generators in the upcoming Base Residual Auction. Such a change could be implemented very quickly. The additional components of the Revised Rule could then be considered and implemented in time for the next auction.

V. ALTERNATIVELY, THE COMMISSION SHOULD CLARIFY THAT PJM MAY TREAT CONTROLLING SPONSORS AS "AFFILIATES" WITHIN THE MEANING OF THE CURRENT TARIFF

As a stop-gap measure, pending full consideration and implementation of a Revised Minimum Offer Price Rule, the Commission should clarify that PJM is permitted to interpret the tariff's definition of "affiliate" to include parties which sponsor and effectively control the participation of other parties in the PJM capacity markets. Such an interpretation, while not entirely without challenges, *see supra* at 45, is appropriate under the special circumstances that the Commission and PJM face here and necessary—but perhaps not sufficient—to avoid a blatant avoidance of the intention of the Rule.

As explained above, the New Jersey scheme transfers not only all economic interest in the capacity to the New Jersey utilities, but also effective control of bidding behavior, from the putative owner and legal seller of the capacity to the state, working hand-in-glove with the utilities. *See supra* at 57-64. The same holds for the Maryland scheme. *See supra* at 64-67. For all economic and practical purposes, the state and its utilities would control the uneconomic capacity to be dumped into the auctions.

The tariff defines two entities to be affiliated when one "controls, is controlled by, or is under common control with" the other. PJM Tariff § 1.0A.01. Regardless whether the sponsored capacity market seller is controlled by a state or the utilities in a global sense, it is clear that under the structure of the proposed schemes, the sponsored capacity market seller is controlled by the state and the utilities as far as participation in the capacity markets is concerned. As this is the only issue relevant to the Minimum Offer Price Rule, it is appropriate to view the capacity market seller as an affiliate of the state and the utilities for this special purpose.

The purpose and effect of deeming the utilities, the state, and the capacity market sellers to be affiliates under the Minimum Offer Price Rule is to stop at least the most conspicuous and artless attempts to sidestep the intent of the Rule. Unless the utilities and the capacity market sellers are regarded as affiliated, the state could direct a net-short utility it regulates to enter into contracts with nominally independent capacity sellers to create artificially suppressed capacity price outcomes. This is, in fact, the basis of the current New Jersey and Maryland schemes. Until the Commission can eliminate the net-short loophole and other flaws entirely, PJM should be permitted to interpret the affiliation in a manner sufficient to narrow the loophole.

VI. OTHER MATTERS

A. Other Proceedings

In accordance with Rule 206(b)(6), 18 C.F.R. § 385.206(b)(6), we state that the specific matters raised in this complaint are not pending before the Commission in any other docket to which P3 is a party.

B. Negotiations Among the Parties

In accordance with Rule 206(b)(9), 18 C.F.R. § 385.206(b)(9), P3 verifies that it has attempted in good faith to resolve these matters, but that those attempts have been unsuccessful. P3 and its members, as well as PJM's independent market monitor, have testified to New Jersey legislative committees considering the New Jersey scheme and attempted to dissuade them from entering upon it for, among others, the reasons stated herein. We have long, but without signal success, sought reforms at the stakeholder level to improve and strengthen the Minimum Offer Price Rule. As such, we do not believe that it would be productive to utilize the Commission's informal dispute resolution procedures.

C. Financial Impact

In accordance with Rule 206(b)(4), 18 C.F.R. § 385.206(b)(4), we cite the independent market monitor's estimate that in the first year alone, the adverse financial impact of the New Jersey and Maryland schemes could be $3 billion. *See* Market Monitor Maryland Report at 4.

D. Service and Form of Notice

In accordance with Rule 206(c), 18 C.F.R. § 385.206(c), we are simultaneously serving a copy of this filing on PJM, the New Jersey Board of Public Utilities and the Maryland Public Service Commission, which parties and regulatory agencies we reasonably expect to be affected by this Complaint. We have attached herein a Form of Notice suitable for publication in the *Federal Register* in accordance with Rule 206(b)(10), 18 C.F.R. § 385.206(b)(10).

E. Request for Fast Track Processing

The issues raised in this Complaint justify Fast Track processing under Rule 206(b)(11), 18 C.F.R. § 385.206(b)(11). As discussed more fully above, *see supra* at 69, timing is of the essence in resolving this complaint. The New Jersey scheme threatens to depress prices in the upcoming Base Residual Auction set to begin on May 2, 2011. While, as explained above, passage of these dates would not raise a legal bar to subsequent resolution of the claims in this complaint, practical considerations strongly favor an earlier resolution. Resolution before May 2 would protect PJM from having to subsequently rerun the 2014/15 Base Residual Auction and protect capacity market participants from having their revenues and liabilities adjusted after the fact. Resolution a few days or weeks earlier would help prevent administrative upheaval. Under these circumstances, the Commission is well justified in exercising its authority to resolve this matter on a Fast Track basis.

F. Refund Effective Date

We request the earliest possible refund effective date, which, by statute, is the date this complaint is filed.[12] Our purpose, as explained above, is for relief, in the form of just and reasonable tariff provisions, to be in effect for the 2014/15 Base Residual Auction, currently scheduled to begin on May 2, 2011.

G. Other Complaint Requirements

In fulfillment of the other requirements for complaints under Rule 206(b), we note as follows: In accordance with Rule 206(b)(1), 18 C.F.R. § 385.206(b)(1), we identify PJM's current, inadequate Minimum Offer Price Rule as the proximate cause of the complaint and note that this heretofore largely theoretical fault of PJM's Tariff threatens to become highly relevant due to the current or threatened actions of New Jersey and Maryland. In accordance with Rule 206(b)(2), 18 C.F.R. § 385.206(b)(2), we explain in detail how the Minimum Offer Price Rule allows violation of the Federal Power Act's requirement of just, reasonable, and non-discriminatory rates, *see supra* at 21-57, and how the various proposed schemes seek to exploit this flaw in PJM's Tariff, *see supra* at 57. In accordance with Rule 206(b)(3), 18 C.F.R. § 385.206(b)(3), we note that a successful exercise of buyer-side market power in the RPM would both expropriate P3 members' current investment in capacity and foreclose opportunities for future investment by P3 members, as explained in greater detail in the body of the argument. *See supra* at 16-74. In accordance with Rule 206(b)(5), 18 C.F.R. § 385.206(b)(5), we note that the relevant impacts are primarily financial, but that these financial impacts are of such

[12] This complaint will not give rise to the issues regarding the resettling of underpayments discussed in *City of Anaheim v. FERC*, 558 F.3d 521 (D.C. Cir. 2009). Here, in addition to this Complaint under section 206, PJM is expected to make a section 205 filing more than 60 days in advance of the May 2011 Base Residual Auction. Hence, the Commission will have authority to effect a new tariff, with a Revised Minimum Offer Price Rule, regardless of whether the change in revenue streams can be characterized as a refund. *See id.* at 524-25 (stressing the distinction between relief permitted under sections 205 and 206).

magnitude that they can be expected to affect all decisions (by P3 members and others) to enter or leave all PJM markets. In accordance with Rule 206(b)(8), 18 C.F.R. § 385.206(b)(8), we have submitted a proposed revision of the Minimum Offer Price Rule, *see* Attachment A, expert testimony by Dr. Roy Shanker, *Testimony of Roy J. Shanker, Ph.D. on Behalf of The PJM Power Providers Group*, P3 Exhibit 1, copies of the New Jersey Law, S. No. 2381, 214th Leg. (N.J. 2011), attached at P3 Exhibit 2, and the Maryland Draft Request for Proposals, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010), attached at P3 Exhibit 3.

CONCLUSION

For the foregoing reasons and in accordance with Rule 206(b)(7), 18 C.F.R. § 385.206(b)(7), we respectfully requests that the Commission grant our complaint and order the Minimum Offer Price Rule to be revised as proposed herein.

Respectfully submitted,
/s/

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Counsel for the PJM Power Providers Group

February 1, 2011

* P3 requests that all further correspondence, communications and other documents relating to this docket be served upon these individuals electronically at gthomas@gtpowergroup.com and Paul.Wight@skadden.com.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-___-000
	)	
PJM Interconnection, L.L.C.	)	

ATTACHMENT A
REVISED MINIMUM OFFER-PRICE RULE[1]

(1) For purposes of this section, the benchmark price for a resource shall be 100% of the asset-class estimates of competitive, cost-based, nominal levelized Cost of New Entry, net of energy and ancillary service revenues, based on an appropriate estimate of the length of service for each asset class. If there are no applicable asset class cost or length of service estimates, the benchmark price shall be based on the Reference Resource. In all other regards, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a) of this Attachment.

(2) In any Base Residual Auction or Incremental Auction, in any LDA for which a separate VRR Curve has been established, any Sell Offer shall be mitigated to its benchmark price before the auction if it is (a) below its benchmark price and (b) not exempt from mitigation under subsection (3).

(3) Notwithstanding subsection (2) a Sell Offer satisfying any of the following conditions shall be exempt from mitigation:

---

[1] This proposed tariff language only reflects the immediately required changes to the Minimum Offer Price Rule. As noted in the Complaint, *see supra* at 54, several additional issues need to be addressed in the longer run.

(i) Any Sell Offer from a capacity resource that has at least twice previously cleared in a Base Residual Auction. In so far as a resource only cleared partially or the Sell Offer otherwise is for a larger quantity than previously cleared (such as, for example, due to uprates), only the twice-previously cleared quantity is exempt from mitigation.

(ii) Any Sell Offer that the Market Monitoring Unit has determined to be no lower than the resource's nominal, levelized, competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets).

(iii) Any Sell Offer based on a resource that the Market Monitoring Unit has determined not to be the beneficiary of any discriminatory payments. A Capacity Market Seller seeking to obtain such a determination, must at such time prior to the auction set by PJM provide to the Market Monitoring Unit all information requested by the Market Monitoring Unit, accompanied by a sworn declaration by an officer of the Capacity Market Seller that such information is accurate and complete. The Market Monitoring Unit shall consider all of the following direct or indirect payments to the market participant to be discriminatory: capacity price subsidies, contracts for difference, state or local tax benefits that exclude existing resources, uncompetitive creation of assets, payments from non-bypassable retail charges, and any other contract, scheme, artifice, device or arrangement which could be used to suppress capacity prices artificially. If the Capacity Market Seller can demonstrate that the payment would have been equally available to a new or existing resource, the payment shall not be deemed discriminatory. Any resource or partial resource previously exempted from mitigation under subsection (i) or (iii) and which subsequently is determined by the Market Monitoring Unit to have been the beneficiary of discriminatory payments shall become subject to mitigation until it becomes entitled to exemption again.

(iv) A Sell Offer based on a base load resource, such as nuclear, coal and Integrated Gasification Combined Cycle, which requires a period for development greater than three years.

(v) A Sell Offer for the Delivery Year 2014/15 based on any resource except a new combustion turbine or combined cycle generation facility.

(4) The Capacity Market Seller may seek review of all determinations made by the Market Monitoring Unit under subsection (3) with the Office of the Interconnection. Both the Capacity Market Seller and the Market Monitoring Unit may seek review of the decision of the Office of the Interconnection with FERC.

(5) Resources designated for self-supply or as price-takers in any capacity auction are not exempt from this subsection. Such designations will only be valid if (a) the resource is exempt from mitigation under subsection (3) and would have cleared at a price of $0/MW-day or (b) if the resource is subject to mitigation under subsection (3) and would have cleared at its mitigated price.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-___-000
	)	
PJM Interconnection, L.L.C.	)	

NOTICE OF COMPLAINT

( )

Take notice that on February 1, 2011, PJM Power Providers Group ("P3") filed a formal complaint against PJM Interconnection, L.L.C. ("PJM") pursuant to section 206 of the Federal Power Act, and Rule 206 of the Commission's Rules of Practice and Procedure, alleging that the tariffs governing PJM's Reliability Pricing Model ("RPM") are unjust and unreasonable and subject to manipulation. In particular, the RPM Minimum Offer Price Rule, designed to prevent the exercise of market power by capacity buyers and their proxies, contains several loopholes which render it ineffective: The Minimum Offer Price Rule ceases mitigation of new resources after, at most, one year; it is unnecessarily limited to sellers which can be identified as net-shorts; it only corrects for very large price impacts; and it does not address capacity designated as self-supply. Accordingly, P3 seeks to revise the Minimum Offer Price Rule to eliminate these loopholes.

P3 certifies that copies of the complaint were served on the contacts for PJM as listed on the Commission's list of Corporate Officials and on parties and regulatory agencies PJM reasonably expects to be affected by this Complaint.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose
Secretary

P3 Exhibit 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-___-000
	)	
PJM Interconnection, L.L.C.	)	

TESTIMONY OF ROY J. SHANKER, PH.D.
ON BEHALF OF THE PJM POWER PROVIDERS GROUP

FEBRUARY 1, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
v.	)	Docket No. EL11-___-000
PJM Interconnection, L.L.C.	)	

INTRODUCTION

Q PLEASE STATE YOUR NAME AND ADDRESS.

A My name is Roy J. Shanker. My address is P.O. Box 60450, Potomac, Maryland 20859.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I have been asked by the PJM Power Providers Group ("P3") to review the provisions of the Reliability Pricing Model ("RPM"), PJM Tariff Attachment DD, that relate to its Minimum Offer Price Rule, section 5.14. Specifically, I was asked to review the Minimum Offer Price Rule provisions to determine whether they effectively limit buyer market power. If they do not, I was also asked to identify specific changes to the Minimum Offer Price Rule that would effectively limit buyer market power and that could be incorporated into the PJM Tariff. I have identified essential changes, and counsel has prepared proposed tariff language that reflects these changes. They are attached as Attachment A to P3's Complaint and Request for Clarification Requesting Fast Track Processing (the "Complaint").

Q PLEASE SUMMARIZE YOUR QUALIFICATIONS TO PRESENT TESTIMONY IN THIS MATTER.

A I have extensive experience with capacity market design in ISO-NE, PJM and NYISO. I have previously offered testimony in Federal Energy Regulatory Commission (the "Commission") proceedings related to capacity market design. I have also testified on a number of occasions regarding the exercise of buyer market power in organized Regional Transmission Organization capacity markets. I recently submitted testimony to the Commission on four occasions in Docket Nos. ER10-787-000, EL10-50-000 and EL10-57-000 related to the exercise of buyer market power in capacity markets in ISO-NE, which is essentially the same issue raised in this case.[1]

I have also been a long-term, active participant on several committees and working groups addressing these issues in the NYISO and PJM markets. In NYISO, I began working on the capacity market concepts prior to the start of the market; in PJM, I participated for seven years in the development of the current RPM markets.

My resume is attached as P3 Exhibit 1-A.

Q HOW IS YOUR TESTIMONY STRUCTURED?

A I begin by summarizing my findings, conclusions and recommended changes to PJM's mitigation rules for buyer market power in capacity markets. My main argument is split into three sections. *First*, by way of background, I describe the Minimum Offer Price Rule and the need to limit buyer-side market power. *Second*, I detail the flaws with the current Minimum Offer Price Rule, and then discuss, by way of example, recent efforts by New Jersey to circumvent the Minimum Offer Price Rule. *Third*, I propose solutions to rectify the current problems with the Minimum Offer Price Rule.

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[1] Some of the content of this testimony is based directly on previous submissions to the Commission. *See ISO New England Inc.*, Docket No. ER10-787-000, Motion to Intervene and Protest of the New England Power Generators Association, NEPGA Exhibit 1, Affidavit Of Roy J. Shanker Ph.D. (Mar. 15, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000 & EL10-50-000, Motion for Leave to Answer and Answer of the New England Power Generators Association, NEPGA Supplementary Exhibit 1, Supplementary Affidavit of Roy J. Shanker Ph.D. (Apr. 13, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000, EL10-50-000 & EL10-57-000, Opening Brief of the New England Power Generators Association, Inc., NEPGA Exhibit 1, Testimony of Roy J. Shanker Ph.D. (July 1, 2010); *ISO New England Inc.*, Docket Nos. ER10-787-000, EL10-50-000 & EL10-57-000, Second Brief of the New England Power Generators Association, Inc., NEPGA Exhibit 8, Supplementary Testimony of Roy J. Shanker Ph.D. (Sept. 1, 2010).

SUMMARY OF FINDINGS OF CONCLUSIONS

Q PLEASE SUMMARIZE THE MAJOR FINDINGS AND CONCLUSIONS YOU HAVE REACHED.

A The Minimum Offer Price Rule, in its current form, is wholly ineffectual as a tool to mitigate buyer market power. My conclusion is based on the following four findings:

1—The conduct screen uses benchmarks that are too low, and the substitute replacement Sell Offer—the mitigated price—is also too low. The conduct screen only mitigates offers below 80% of the Net Asset Class Costs of New Entry, or 70% of the Reference Resource (combustion turbine) Net Cost of New Entry. If the conduct threshold—as well as the impact threshold, discussed below—are actually crossed, the "mitigated-to" level of the substitute Sell Offer is only 90% of the Net Asset Class Costs of New Entry. The conduct and the "mitigated-to" thresholds both still allow for material market price suppression. They effectively combine to cap the market price at the lesser value of the conduct screen or the "mitigate-to" price. Obviously it is wrong for such a cap to be less than 100% of the *average* level of the cost of new entry.

2—The impact thresholds in the existing Minimum Offer Price Rule that trigger actual mitigation are also far too low. As I demonstrate, buyers can improperly transfer nearly a billion dollars a year to themselves from sellers without triggering the impact threshold. Again, the impact level sets a cap on market prices below the competitive level that otherwise would occur. Any value other than zero allows for the successful exercise of market power.

3—In the rare circumstances when mitigation may actually apply, the Minimum Offer Price Rule mitigates too briefly. It only mitigates in the first Base Residual

Auction where a Sell Offer by a new entrant is submitted. The Minimum Offer Price Rule thus can only mitigate a transparently uneconomic and manipulative offer for *one year*, regardless of whether the facility remains uneconomic. Further, a party may easily circumvent this one-year effective period by gaming the anticipated in-service date of a unit.

4—Finally, the Minimum Offer Price Rule only applies to a very limited, and easily manipulated, subset of resources. There are too many exceptions to its application. There are several, but I focus on three:[2] (a) the Minimum Offer Price Rule only applies to net buyers of capacity, but as the Commission has previously determined, a net buyer screen is easily circumvented to allow uneconomic entry and is ineffective on its own in identifying anti-competitive conduct;[3] (b) the Minimum Offer Price Rule's definition of Planned Resources is far too narrow; and (c) the existing rules may ignore self-supply, possibly permitting a seller to designate an uneconomic unit as self-supply and circumvent any buyer-side mitigation. All of these exceptions should be eliminated.

Collectively these flaws make the current Minimum Offer Price Rule largely useless to control and mitigate the exercise of buyer-side market power.

Q WHAT ARE YOUR RECOMMENDATIONS BASED ON THESE CONCLUSIONS?

A The Minimum Offer Price Rule must be modified and strengthened to create a viable buyer market power mitigation tool for the PJM capacity markets. *First*, any resource would pass the conduct screen if it bids at least 100 percent of the nominal levelized net

[2] I understand that counsel discusses other exemptions to mitigation in the rules. I agree that these other exemptions should be eliminated, but I have not undertaken to address in this testimony every loophole and exemption to mitigation in the current rules.

[3] The net buyer test in the Minimum Offer Price Rule is even worse because the specific thresholds in the test approximate the *status quo*, permitting material price manipulation and suppression by buyers without the screens ever being triggered.

Cost of New Entry of the Reference Resource (a combustion turbine as defined in Attachment DD of the PJM Tariff, section 2.58).

Any resource bidding below this threshold could still pass the conduct screen if it establishes that it has not received any out-of-market payments, as determined at the time of the offer. The Independent Market Monitor or PJM will look for any indication, direct or indirect, of the seller being the beneficiary of discriminatory out-of-market payments not generally available to all market participants (e.g., a contract supporting new entrants only). Projects built by rate-based entities, or otherwise supported by non-bypassable retail rates, shall be assumed to fail the screen. A senior officer of the new entrant or its parent company shall certify the accuracy of all information provided to the Independent Market Monitor. To the extent that any new resources represent an attempt to manipulate market prices, they will be deemed to have failed the conduct test, whether specifically falling into the above categories or not.

Q SHOULD ANY DISTINCTIONS BE MADE BETWEEN LONG-LEAD-TIME AND SHORT-LEAD-TIME RESOURCES?

A Yes. Longer-lead-time new entrants are those that will take more than three years to move from an Interconnection Service Agreement to commercial operation. Longer-lead-time resources thus require a determination of mitigation status outside the time horizon of the PJM capacity auction process. I recommend an initial determination of whether a longer-lead-time unit is economic at the time the Interconnection Service Agreement is signed. The unit’s own nominal levelized Unit Specific Net Cost of New Entry should be compared with a projection of future auction prices. If the unit is economic under this test, then at the time of actual commercial operation, it may offer into the market at its Avoidable Cost Rate or less.

If it is uneconomic, a new long-lead-time unit should be mitigated at its nominal levelized Unit Specific Net Cost of New Entry as determined at the time of Interconnection Service Agreement signing. Mitigation would only cease after the facility clears at least two Base Residual Auctions. This is consistent with the remedies that the Commission recently utilized in addressing the NYISO In-City Buyer-Side Mitigation, as I explain below.

Short-lead-time projects that can be built within the RPM three-year-lead window, presumptively including all new combustion turbines and combined cycle generation units, would not have the same option. My recommendations recognize that the RPM auction itself and associated clearing prices can be integrated into the mitigation process for these short-lead-time resources.

Q HOW WOULD THE MITIGATION BE APPLIED?

A For any project failing the screen, the new entrant's offer in PJM capacity auctions will be mitigated to 100% of the nominal levelized Unit Specific Net Cost of New Entry. As I explain, this is the appropriate value to adopt in PJM given conditions in the market.

Q HOW WOULD SHORT-LEAD-TIME NEW RESOURCES ESTABLISH THEIR UNIT SPECIFIC NET CONE?

A Upon failing the conduct test, short-lead-time resources will receive a determination of a nominal levelized Unit Specific Net Cost of New Entry as a mitigation level. The Independent Market Monitor or PJM shall determine a nominal levelized Unit Specific Net Cost of New Entry, subject to appeal to the Commission. The nominal levelized Unit

Specific Net Cost of New Entry shall be calculated based on the actual or projected costs of the new entrant with the exception of capital costs, which should be the Independent Market Monitor's current generic capital cost assumptions for similar new units in the PJM markets. This value shall be calculated in the same way that PJM currently calculates the annual nominal cost of the Reference Resource. The energy and ancillary services offset for the Unit Specific Net Cost of New Entry shall also be calculated in the same way that the Independent Market Monitor currently calculates it for the Avoidable Cost Rate calculations.

Q HOW LONG WILL THE MITIGATION LAST?

A The mitigation offer floor shall remain in effect until a new entrant clears the Base Residual RPM Auction at least twice. Mitigation should cease for only the MW portion of a new entrant's mitigated offer that clears the market at least twice. The non-cleared portion of the new entrant will continue to be mitigated to the applicable offer floor.

Clearing will be incrementally determined for the new entrant based on any portion of the resource that clears. The new entrant cannot participate in any other PJM auctions until it first clears two Base Residual Auctions at the nominal levelized Unit Specific Net Cost of New Entry.

For all projects, both short- and long-lead-time, the Independent Market Monitor shall have the ability to reinstate the mitigation offer floor if the Independent Market Monitor determines that any party, regardless of whether the party is a new entrant, has acted in a manner to improperly influence the clearing price of a Base Residual Auction.

Q DO YOU RECOMMEND ANY OTHER CHANGES?

A Yes. Consistent with the NYISO In-City Buyer-Side Mitigation, I recommend that the net-buyer-of-capacity conduct screen should be eliminated. I also recommend that any real or implied waiver of mitigation for self-supply should be removed. A mitigated new entrant cannot be used for self-supply until it clears in two Base Residual Auctions. And I recommend elimination of the limitation in the Minimum Offer Price Rule that restricts its application only to some Planned Generation Capacity Resources.

Q DOES THE TARIFF LANGUAGE PROPOSED BY COUNSEL EXACTLY MATCH THESE RECOMMENDATIONS?

A Not exactly. To allow expedited implementation, my understanding is that counsel has prepared language that would initially use 100% of the *Asset Class* cost information for the conduct screen and the "mitigate-to" values, rather than using the Reference Resource as I recommend. My understanding is that this is an effort to expedite relief. I would, however, recommend that the structure that I propose be implemented as soon as possible, and no later than at the time of any required compliance filing by PJM in the anticipated consolidated proceedings.

I. BACKGROUND

A. THE MINIMUM OFFER PRICE RULE

Q PLEASE SUMMARIZE THE MINIMUM OFFER PRICE RULE.

A The Minimum Offer Price Rule is contained in the PJM tariff, Attachment DD, section 5.14(h). The intent of the Minimum Offer Price Rule is to prevent uneconomic entry by repricing Sell Offers that are less than the defined floors relative to the Cost of New Entry. The goal of the Minimum Offer Price Rule is to mitigate buyer market power and price discrimination and suppression. To achieve this goal, the Minimum Offer Price

Rule applies a general form of conduct and impact mitigation to the potential exercise of buyer market power in the first Base Residual Auction in which a Sell Offer is submitted—and *only* in the first Base Residual Auction in which a Sell Offer is *submitted*.

Under the Minimum Offer Price Rule, the Independent Market Monitor develops asset class estimates of real levelized net costs of new entry (the "Net Asset Class Costs of New Entry"). The Independent Market Monitor then compares actual Sell Offers of new entrants to these reference levels.[4] The conduct screen is failed if the Sell Offer is less than 80% of the Net Asset Class Cost of New Entry and if the Offeror is considered a net buyer.[5] At that point, the Offeror is informed of the conduct test failure and is given an opportunity to justify the basis for offering at a lower price than the threshold.

The Independent Market Monitor also conducts an impact test by rerunning the Base Residual Auction and using a substitute Sell Offer. The substitute Sell Offer is set at 90% of the applicable Net Asset Class Cost of New Entry or 80% of the reference Net Cost of New Entry if no other value is available. The impact test fails if the change in Clearing Price for the locational delivery area exceeds the greater of: (1) $25 or 20% for a locational delivery area of 15,000 MW or more; (2) $25 or 25% for a locational delivery area of between 5,000 and 15,000 MW; or (3) $25 or 30% in a locational delivery area of less than 5,000 MW. If the impact test is failed, the original auction

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[4] Under the current tariff, reference levels are zero for base load resources, hydroelectric, upgrades or any new entry unit being developed in response to a state regulatory process that (1) is designed to resolve reliability needs, (2) allows PJM to participate, (3) gives due notice and (4) provides an opportunity to comment. If no Net Asset Class Cost of New Entry is available, the standard will be 70% of the reference Net Cost of New Entry for the specified locational delivery area.

[5] The net buyer requirement is a function of the size of the locational delivery area. The net short criterion is 10% for a locational delivery area of less than 10,000 MW and 5% for a locational delivery area of 10,000 MW or more.

result is rejected and a new auction Clearing Price is established using the substitute Sell Offer.

B. BUYER-SIDE MARKET POWER

Q THE GOAL OF THE MOPR IS TO LIMIT BUYER-SIDE MARKET POWER. WHY IS THERE A NEED FOR BUYER-SIDE MARKET POWER MITIGATION?

A It has become increasingly clear to me that certain states and market participants operate under the belief that price discrimination is a legitimate and desirable goal to be pursued in a capacity market design. These entities repeatedly attempt to find ways to pay market rates only to new entrants, and suppress prices for existing capacity suppliers. These views persist notwithstanding the Commission's findings that such actions are discriminatory and unjust. And while artificially suppressed prices may appear attractive to consumers in the short run, they cannot be sustained, and actually result in higher costs in the long run.

Q WHEN ARE BUYER MARKET POWER MITIGATION MECHANISMS NECESSARY?

A Mechanisms to screen and mitigate buyer market power are necessary when there is insufficient intrinsic competition, or if market shares are highly concentrated, or if it is possible to circumvent the market for cost recovery. Such conditions exist in PJM. Indeed, the potential exercise of buyer market power is of particular concern in PJM because the design of the demand curve allows relatively small increases in supply to significantly depress market-wide prices. This is coupled with the potentially concentrated purchasing power of several buyers or representatives of buyers (e.g., states or state agencies), who have the ability to make discriminatory investments in uneconomic capacity resources through mechanisms such as out-of-market subsidies.

For example, buyers or representatives of buyers, can use state-sponsored contracts to recover their uneconomic investments through direct or indirect non-bypassable charges. Such non-bypassable charges include cost-of-service rate making, distribution level billing surcharges or taxes.

Q CAN YOU PROVIDE AN EXAMPLE TO DEMONSTRATE THESE CONCEPTS AND CONCERNS?

A Yes. While PJM has a multi-zone locational design, each with a locational reliability requirement and demand curve, the general principles of market manipulation by uneconomic entry are easily identified. Assume that the reliability requirement for capacity—i.e., the quantity where the price on the Variable Resource Requirement or demand curve equals net Cost of New Entry—is about 40,000 MW. For a frame of reference, this is approximately the size of the Eastern Mid-Atlantic Area Council (EMAAC). Assume there is a net internal requirement of approximately 32,000 MW with 8,000 MW of import capability. Also assume that there is no net need for new capacity and the target need was just filled by 1 MW offered at the nominal levelized Reference net Cost of New Entry. Additionally assume that 400 MW of uneconomic capacity was procured through a state-sponsored process and offered into the auction at a price of zero. Assume further that the actual net Cost of New Entry used to develop the location's demand curve is \$260 per MW-day and that this is the out-of-market price actually paid for the 400 MW of excess new capacity procured through a governmental entity's "new supply only" solicitation.[6] Finally, assume that the slope of the Variable

[6] The example is a rough approximation of the 2013-14 Base Residual Auction for EMAAC (a designated locational deliverability area in PJM). Note that in this recent auction, the net Cost of New Entry for EMAAC was \$261.06/MW-day, there was approximately 40,000 MW of unconstrained capacity required and the import capacity

Resource Requirement curve results in a 20% reduction in price (based on net Cost of New Entry, this 20% equals $52 per MW-day) for each 1% of additional internal supply in the relevant region of the demand Variable Resource Requirement curve. This is consistent with the slope of the PJM demand curve.

Based on these assumptions, absent the 400 MW of uneconomic entry, the clearing price would be $260 per MW-day. With the excess 400 MW (i.e., 1% of the reliability requirement for capacity) under the Variable Resource Requirement curve, the price would drop approximately 20% to $208 per MW-day. Yet, 40,400 MW would be purchased. Thus, the net effect of the price suppression of the unneeded 400 MW is a reduction of payments of approximately $570 million, even after accounting for the purchase of the excess capacity.[7]

Q DOES THIS STRATEGY WORK WHEN THE BUYER REPRESENTS ONLY A PORTION OF THE MARKET?

A Yes. While the above example is for the market as a whole, the mechanics of the process still work even if the load-serving entity purchasing the excess serves only a portion of the market. For example, consider what happens if the load-serving entity serves only half of the load in the market. In this case, depressing the price by the same amount has slightly less than half the impact for the buyer trying to manipulate prices. This is

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was approximately 7,000 MW. Thus, approximately 33,000 MW cleared at the EMAAC price. For the example in my testimony, I have used 40,000 MW, 8,000 MW, and 32,000 MW, respectively.

[7] The original annual internal costs are equal to $3,036,800,000 (32,000 MW x 365 days x $260/MW-day = $3,036,800,000). After the uneconomic addition, the annual internal costs are equal to $2,459,808,000 (32,400 MW x 365 days x $208/MW-day = $2,459,808,000) plus the remaining cost of $7,952,000 (400 MW x 365 days x $52/MW-day = $7,592,000), which equals a total internal cost of $2,467,400,000 following the uneconomic addition. This total amount reflects the full market cost of the uneconomic addition for a net savings of $569,400,000. This assumes that imports would remain the same and due to capacity transfer rights the net effect on zonal imports would be a wash. Alternatively the example could be seen as applying to a stand alone system of 32,000 MW.

because the buyer still purchases all of the out-of-market uneconomic new capacity, but only "saves" on a basis of 16,000 MW instead of 32,000 MW. In this case the net price suppression is still very large, with a net reduction after paying for the uneconomic entry of approximately $281 million.[8]

Q WHEN THE PARTY EXERCISING BUYER-SIDE MARKET POWER CONTROLS ONLY A FRACTION OF THE MARKET, WILL IT SUSTAIN A COMPETITIVE DISADVANTAGE EVEN THOUGH ITS TOTAL COSTS ARE REDUCED?

A Yes. This occurs because the party exercising buyer-side market power—the party bidding into the market below cost—incurs the "extra" cost of the uneconomic new resource. It benefits from the price suppression, but it also has to incur the cost of building a new unit. Everyone else—all of the remaining participants who purchase capacity—get the same price suppression benefit without the expense of building the unit. This is why the role of states as "partners" is an important element in this type of behavior. The state can impose non-bypassable charges or other discriminatory practices that assure recovery for the party bidding below cost, to permit it to make up the costs it incurs to build the plant. The party exercising market power bids below market but receives a discriminatory payment or subsidy from the state. As discussed later, recognizing this factor becomes a crucial element in the appropriate design of a mitigation strategy for short-term resources.

But if there is no state or other "partner" to protect the party seeking to exercise market power, the party engaging in anti-competitive behavior will likely have an

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8 When the savings are only on half the market, the calculations lead to an original annual internal cost of $1,518,400,000 (16,000 MW x 365 days x $260/MW-day = $1,518,400,000). After the uneconomic addition, the annual internal costs is $1,229,904,000 (16,200 MW x 365 days x $208/MW-day = $1,229,904,000) plus the subsidy payments for the 400 MW of $7,592,000 (400 MW x 365 days x $52/MW-day = $7,592,000) for a total of $1,237,496,000. This creates a net savings of approximately $281 million.

average price that is significantly higher than its competitors who serve the remaining load in the system (or locational delivery area). This occurs because while the party engaging in anti-competitive behavior buys some power at the suppressed prices, it also pays "market" for the additional uneconomic supply. Its competitors, on the other hand, only pay the suppressed market-clearing price.[9]

Under a competitive regime where retail load may be served by multiple sellers, this type of behavior, even though profitable in the short term for the party exercising market power, cannot persist over the long term because, although the costs to the exerciser of market power decline, the party exercising market power would have higher average unit costs than its competitors because it is the only party that pays the price for the distortion. Ultimately this factor would cause the party exercising market power to lose market share to its competitors and, in turn, eventually lose the benefits of exercising market power in the first place. Thus, while there may be a short-term incentive for this behavior when there is competition for sales, it is not sustainable in the long term, at least not without state help to socialize the cost of the exercise of market power across all of the beneficiaries.

Q HOW, THEN, CAN A BUYER SEEKING TO EXERCISE MARKET POWER BENEFIT FROM ITS BEHAVIOR?

A If a party with only partial market share can be *assured of recouping its investment* when it purchases excess capacity in a discriminatory manner, it will always have the incentive to exercise market power. It is protected from the long-term competitive downside noted above. Market shares may adjust, but the guaranteed recovery will allow the party with

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[9] This assumes that there are multiple, independent capacity purchasers.

only partial market share to continue to make the uneconomic investment without experiencing a loss, despite the fact that the uneconomic excess is simultaneously dropping prices for the market as a whole.

Q WHAT DO YOU CONCLUDE FROM THIS?

A The exercise of buyer market power is surest, safest, most profitable, and most harmful when it occurs under the direction of a state or regulatory agency. States or regulatory agencies are in the best position to provide discriminatory mechanism(s) (e.g., contracts, regulated recovery, etc.) to assure that the parties procuring or sponsoring uneconomic resources recoup their expenses. States and regulatory agencies could act alone without "partnering" with market participants, but market participants—particularly those with only partial market share—typically must have the help of the states or regulatory agencies to successfully exercise buyer market power.

Thus, to be effective, buyer market power mitigation must be focused not only on those directly making uneconomic investments, but also on those for whom these exercisers of market power may be acting as an agent. The Commission has correctly recognized in the past that this use of a proxy in determining the source of uneconomic entry is to be anticipated and prevented.[10] The key observation is that access to assured recovery via out-of-market payments or subsidies to support uneconomic entry is an essential element of the effective long-term exercise of buyer market power. Governmental or quasi-governmental entities provide the mechanisms to assure this recovery. Any effective mitigation regime must examine the conduct of agents or proxies that would indirectly exercise market power. Ideally these mechanisms would simply be

[10] *E.g.*, *N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 100, *order on reh'g*, 124 FERC ¶ 61,301 (2008), *order on reh'g and clarification*, 131 FERC ¶ 61,170 at P 133 (2010).

banned, but absent that ability, actions are necessary to keep this type of market power from distorting prices in the Commission's jurisdictional markets.

Q DOES THE EXERCISE OF BUYER MARKET POWER REDUCE PRICES?

A Absolutely not. As the Commission has observed, while this exercise of market power seems an attractive proposition for load—at least in the short run—it is disastrous for the viability of competitive markets in the long run.[11] Suppliers are victimized by price discrimination, wherein only new entrants receive the competitive market price, while all other existing units receive an artificially suppressed payment. This effectively creates an unjustified pricing structure where competitive existing suppliers are discriminated against vis-à-vis subsidized new entrants. This occurs even though all market participants provide the same reliability product or service. Certain individual new entrants, by exercising buyer-side market power or cooperating with others who are exercising market power, are simply paid a higher price and all other existing suppliers unjustifiably are paid a lower price. There is no benefit to market efficiency here; there simply is an unwarranted transfer of resources from sellers to buyers, coupled with the waste of resources and distortion of prices and consumption.

The end effect of the exercise of buyer market power, then, is that no one will seek to enter the market other than by subsidized bilateral agreements. A supplier entering the market *without* such protection would be asking to be victimized as soon as the initial "lock-in" period ends. It is not likely that the states will stop exercising market power if they successfully can. In the short term, it always looks like it will be cheaper to just pay new entry. But in the long term, it is disastrous. Eventually all favored "new

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[11] *N.Y. Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 100-06 & nn.55-56.

suppliers" become "existing suppliers," subject to victimization. To compensate for that risk, any rational new entrant would seek to be protected by continuous price erosion via ever higher new entry offers, thereby encouraging an even greater use of buyer market power as the perceived cost of new entry rises. As the market structure is unwound, risk shifts back to consumers due to the out-of-market payments, and one of the core benefits of competitive markets is defeated.

Q DOES THIS TYPE OF BUYER MARKET POWER HAVE OTHER ADVERSE IMPACTS?

A Yes. These additional adverse impacts relate to the retention of existing units that would otherwise be economic but for the price distortion caused by the exercise of buyer market power. By artificially depressing prices, some resources, which otherwise would have been committed in a competitive auction, will fail to clear the market. These resources will then retire (unless they are needed for reliability, thereby requiring another out-of-market payment). This effect will inefficiently accelerate the "turnover" of the entire capital generation stock and, as discussed below, will create a need for reliability must run contracts.

In addition, basic consumer decision-making and resource allocation will be skewed. Consumers will see distorted price signals. They become more likely to over-consume electric capacity as prices are artificially suppressed. Resources will be directed into electric consumption that should be used elsewhere, and the value of conservation and associated demand response activity will be depressed.

Q ARE THERE OTHER ADVERSE EFFECTS ASSOCIATED WITH THIS BEHAVIOR?

A Yes. It also has the perverse impact of punishing those market participants that attempted to control their own risk by entering into hedging agreements or similar arrangements to limit their exposure to fluctuations in market prices for capacity. Such parties are forced into making double payments. First, they pay for the costs they prudently incurred for their own risk management, and they pay a second time when charges related to supporting the discriminatory procurement of out-of-market new generation are imposed on them. Over time, in the face of such market power, there would also be the expectation that parties would cease to enter into their own risk management arrangements, further distorting consumption decisions.

In sum, distorting the market by exercising buyer market power ultimately transfers money from sellers to buyers. It harms prudent bystanders. This does not benefit society, but instead decreases overall social welfare. The Independent Market Monitor echoed these same conclusions in reference to the potential out-of-market subsidy for uneconomic and unneeded new entry by the State of New Jersey.[12]

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[12] The Independent Market Monitor stated as follows:

> The result of such a subsidy by New Jersey ratepayers would be to artificially depress the Reliability Pricing Model (RPM) auction prices below the competitive level, with the result that the revenues to generators both inside and outside of New Jersey would be reduced as would the incentives to customers to manage load and to invest in cost effective demand side management technologies. … This substantial reduction in revenue would affect the investment decisions of current owners of capacity and potential investors in capacity both in New Jersey and in areas outside of New Jersey. The likely result is less investment in new and existing capacity, in the form of generation resources and demand response. Depressing the price in New Jersey would also mean that the required direct subsidy by New Jersey ratepayers would increase for the specified procured MW, with perhaps significant unintended consequences for the business and residential customers who would have to pay the mandatory subsidy. The result of depressing RPM prices in New Jersey would also be to increase the probability that additional subsidies by New Jersey ratepayers will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in New Jersey. The result of depressing RPM prices over a broad section of PJM would be to increase the probability that subsidies by ratepayers in other states will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in that area.

Q WHAT IS THE LONG-RUN EFFECT OF THIS TYPE OF EXERCISE OF BUYER MARKET POWER?

A These corrosive elements ultimately undermine incentives for independent private investment. Eventually all capacity will either be based on the long-term discriminatory procurements or reliability must run contracts. This effectively defaults back to a world that looks like central rate-based planning, coupled with a pricing path over time that distorts consumption and operational decision-making and destroys existing private investment in the market. Unless fully mitigated, this combination of events assures the demise of a market-based solution.

This is the very type of inefficient regime that led to the movement to competitive markets in the first place. The only difference is that here the existing capacity that is not the beneficiary of the discriminatory prices will receive the artificially reduced prices rather than the same cost-of-service approach applied to all resources equally. There will never be sufficient unsubsidized private new entry because prices over time will always be well below the required average true Cost of New Entry. This risk will translate into higher costs as those participants that obtain a discriminatory contract will add an additional margin into their offers to address the fact that at the expiration of such an agreement, they too will be ready victims of price discrimination in the ensuing years.

Monitoring Analytics, Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market at 1-2 (Jan. 6, 2011), http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf ("IMM Analysis").

II. THE MINIMUM OFFER PRICE RULE'S MATERIAL FLAWS AND HOW THEY CAN BE EXPLOITED

A. THE MINIMUM OFFER PRICE RULE'S FOUR PRIMARY FLAWS

Q HOW MANY FLAWS HAVE YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE WHICH PREVENT IT FROM MITIGATING BUYER MARKET POWER?

A I have identified four material failures in the design of the Minimum Offer Price Rule. Each limits the Minimum Offer Price Rule's effectiveness to prevent significant exercises of buyer market power. Collectively the flaws make the Minimum Offer Price Rule virtually useless. Thus, the unjustness and unreasonableness of the Minimum Offer Price Rule is practically transparent.

Q WHAT IS THE FIRST FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A Both the cost benchmarks in the conduct screen and the substitute Sell Offers that are put into effect when mitigation is triggered are too low. Under the Minimum Offer Price Rule's conduct screen, offers are not mitigated unless they are less than 80% of the applicable Net Asset Class Cost of New Entry, or if there is no applicable asset class for that resource, to 70% of the Net Asset Class Cost of New Entry for a combustion turbine (the Reference Resource). Then, assuming the conduct screen is failed and mitigation will be applied, offers are re-priced to 90% of the applicable Net Asset Class Cost of New Entry, or if there is none, to 80% of the Net Asset Class Cost of New Entry of the Reference Resource.

These thresholds are too low. They permit huge cost shifts from sellers to buyers through the exercise of buyer market power. They artificially cap market prices to levels well below Cost of New Entry. This must be seen as unjust and unreasonable.

Q WHAT IS WRONG WITH THESE BENCHMARKS?

A Consider the basic objective of mitigation: to identify the exercise of market power and, once identified, to take action to return pricing to competitive levels. A conduct threshold of 80% or 70% permits offers 20% to 30% below economic levels to go unmitigated. This permits the extensive exercise of buyer market power before mitigation is even triggered just by bidding in subsidized new entry at a level slightly higher than the screen, e.g., 81%. Consider the effect of a 20% threshold in the EMAAC LDA. The EMAAC net Cost of New Entry was approximately $260 per MW-day for the last Base Residual Auction. Twenty percent equates to $52 per MW-day. Applied to the approximately 33,000 MW of capacity inside the EMAAC locational delivery area, there would be a permissible total annual dollar exercise of buyer market power of $626 million *before mitigation is even considered* ($52/MW-day x 365 days x 33,000 MW = $626,340,000).

And assuming that mitigation is triggered, the overall mitigation is ineffective if the resulting "mitigated-to" pricing or other actions do not replicate closely the anticipated competitive levels that should have existed absent the exercise of market power. In the case of the Minimum Offer Price Rule, the substitute Sell Offer—which is used to establish new auction results when uneconomic entry is found—is too low. It is unclear why any value below 100% of the nominal levelized Unit Specific Net Cost of New Entry should be utilized for the substitute Sell Offers that constitute the "mitigated-to" values.

Q TYPICALLY FOR "MITIGATED-TO" VALUES, SOME ADJUSTMENT WOULD BE MADE FOR POTENTIAL INACCURACY WITH THE SUBSTITUTE PRICE. WHY DOESN'T THAT JUSTIFY THE USE OF A VALUE BELOW 100%?

A Actually, in this specific situation that type of logic does not apply. In fact, other considerations support mitigation to a higher substitute Sell Offer, not a lower one. Ideally, any bid from a subsidized party would be excluded. However, if such bids are allowed, they must be mitigated to at least 100% of their nominal levelized costs to prevent adverse effects in the operation of the capacity market.

There are two main reasons for using 100% as a lower bound. First, in the presence of market power, the mitigation floor offer is likely to become the *cap* on prices for capacity in the market. The definition of the "mitigated-to" target price in this situation is a nominal levelized long-term price that represents the *average compensation* that is needed to support new entry over time. Buyers with market power can act to eliminate the ability of prices to rise above the offer floor, which would be possible under the PJM demand curve structure, but for the market power. The notion that the prices would be capped at average some of the time, and less than average other times clearly points out the problem: who will privately invest under such conditions? Similarly, this clarifies that while the mitigation is to the appropriate average value, that value may be too low to achieve the goal of reproducing long-term competitive market conditions, as private entry will still be discouraged from entering the market absent a subsidy. Thus 100% has to at least serve as a lower bound.

Second, the cost of choosing too high a substitute Sell Offer is much less than the cost of choosing too low a substitute Sell Offer. In the energy market, mitigation often occurs when there is a lack of competitive supply alternatives. Thus there is concern regarding not forcing a supply at what might be less than cost because the supply must be used, there typically is no alternative. That is not the case with the exercise of buyer-side market power in the capacity market. If the supply from a specific party offering subsidized capacity is mitigated, no barriers are created for others to put forward competitive alternatives. I discuss the importance of alternative competitive supply and its relevance to setting mitigation levels further below.

The implications of this can best be seen by looking at the issue of replicating competitive results from a "cost of the errors" perspective. That is, what is the relative harm or benefit from choosing too high of a value for the substitute Sell Offer versus too low a value. When this analysis is done, and the availability of competitive alternatives is taken into account, the clear conclusion is that it is better to have an upward bias in the substitute Sell Offers, if there is going to be any bias at all. Indeed, a value greater than 100% could easily be justified in the current circumstances.

For example, if the mitigated price set at the nominal levelized Unit Specific Net Cost of New Entry were deemed too high, what is the harm? The worst that happens is that the mitigated offer fails to clear, and presumably the new resource would not be built. This would occur because either there was no need for it, or if there was a need, it was filled by a lower-cost alternative competitive supplier. This is hardly a bad result, and in fact, is what *should* happen in a market. Empirically we know we have significant additional supply in PJM.

Alternatively, if the mitigated price is too low, and effectively sets a cap on the market below the actual cost of new entry, competitive entry is eliminated, prices are suppressed, and price discrimination is allowed. This assures the destruction of the market, because by definition the prices are being set at levels such that they will never be compensatory for a new entrant. No one will enter a market where the expected revenues are capped at less than the needed average price.[13]

In sum, due to competitive entry, long-term market prices would not be expected to change from competitive levels if the mitigation were set at too high a price. In stark contrast, however, if the mitigation value selected were too low, prices would be artificially depressed. This in turn would lead to the cascading failure of any market solution: no party will privately enter the market if, even when buyer market power is mitigated, prices are set below competitive levels. Taking the perspective of designing mitigation measures to protect the *market*, as opposed to protecting individual market participants, it becomes clear that the right course is, at minimum, to mitigate to the nominal levelized Unit Specific Net Cost of New Entry.

With the above in mind there really is no harm to over-mitigation with a "too high" substitute Sell Offer versus precipitating the destruction of the market with under-mitigation via a "too low" offer. In this context, use of the 100% value for the substitute Sell Offer is conservative. But under no circumstances could 100% be considered too *high*.

I believe that this is an even more compelling logic given that the specific mitigation I am proposing explicitly waives any mitigation for a true competitive entrant

[13] A parallel logic applies to my recommendation regarding the conduct screens. A conduct screen below 100% also allows those seeking to exercise market power to simply bid just above the screen, and thus to suppress prices to less than the average Cost of New Entry. Thus, if the conduct screen is 80%, then market power can be asserted by simply bidding 81%, still well below average costs. This effectively caps the market at the level of the conduct screen, again assuring no private entry.

that can demonstrate no out-of-market/discriminatory support. Such a resource may offer at as low of a price as they wish.

Q WHAT IS THE SECOND FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A The impact thresholds in the Minimum Offer Price Rule are far too lax. In general, mitigation approaches recognize that they can not directly prevent the exercise of market power, but rather, they can identify it, and once identified, take actions to return pricing to expected competitive levels. If the impact levels of a mitigation process allow any material deviations from competitive levels without triggering any action, the mitigation process is fundamentally flawed. This is the case with the Minimum Offer Price Rule. Much like the conduct screen and the "mitigate-to" values that both set *de facto* price caps, the impact level will represent an assured amount of price suppression. Intentionally allowing a value greater than zero is the same as capping prices below the average cost of new entry. Again this is transparently unjust and unreasonable.

As stated above in the description of the Minimum Offer Price Rule, if the conduct test fails, the Independent Market Monitor implements an impact test. In the impact test, the Independent Market Monitor reruns the Base Residual Auction using a substitute Sell Offer. The substitute Sell Offer is set at 90% of the applicable Net Asset Class Cost of New Entry or 80% of the reference Net Cost of New Entry if no other value is available. The impact test fails if the change in Clearing Price for the locational delivery area exceeds the greater of: (1) $25 or 20% for a locational delivery area of 15,000 MW or more; (2) $25 or 25% for a locational delivery area of between 5,000 and 15,000 MW; or (3) $25 or 30% in a locational delivery area of less than 5,000 MW.

The original logic behind these types of thresholds was to allow some wiggle room prior to triggering mitigation. However, with the existing Minimum Offer Price Rule impact thresholds, the wiggle room equates to a mammoth gap in market power mitigation and enforcement, and as discussed above, in this specific competitive environment, such flexibility is not justified.

Q HOW DOES HAVING LAX IMPACT THRESHOLDS PREVENT THE MINIMUM OFFER PRICE RULE FROM LIMITING BUYER MARKET POWER?

A The effect of lax impact thresholds is easily seen by example. Consider the 20% impact threshold for locational delivery areas greater than 15,000 MW, such as the EMAAC LDA, to use the same example as above. Assume that the clearing price in the last auction was $245 per MW-day. A 20% impact equates to $49 per MW-day. Applied to the approximately 33,000 MW of capacity inside the EMAAC locational delivery area, there would be a permissible total annual dollar amount of price suppression of approximately $590 million before the impact threshold is even crossed ($49/MW-day x 365 days x 33,000 MW = $590,205,000). And that is for EMAAC only; the excess supply would ripple through the rest of the market, increasing the effect of such lax thresholds. In larger zones, even greater price suppression could occur without mitigation ever being triggered. All that is needed to manipulate the market is to estimate the quantity that can be added to the market without triggering the impact threshold. Given the use of a demand curve, and known demand, it would not be difficult to derive such values. Thus market power is likely to be exercised up to the allowable impact threshold. Further, this effect would easily be compounded if multiple parties engaged in the same behavior or a single party did it repetitively over time, or both, with the effect being both cumulative and devastating.

Q WHAT IS THE THIRD FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A The mitigation is too limited in its duration. The prohibition on uneconomic offer prices only applies to the *first* Base Residual Auction. The Sell Offer is only mitigated one time regardless of need and regardless of whether resource clears or not. Thereafter it can be offered at any level, including zero. In the context of some of the long-term bilateral agreements that have already been proposed to artificially depress prices, the loss of one year's price suppression simply becomes part of the calculus of the "right" uneconomic quantities to be subsidized.[14] The loss of a single year, however, is insignificant to the exercisers of market power in relation to the overall price suppression they can achieve. They can easily make up the first year of losses with savings during the later years of a bilateral agreement.

Further, the Minimum Offer Price Rule only applies to a single Base Residual Auction, yet the Base Residual Auction is only one of the auctions that apply for any specific delivery year. If a unit were mitigated under the Minimum Offer Price Rule in its first Base Residual Auction, it would still retain the ability to be offered in each of the incremental auctions. While this may not materially depress prices in the first year, it does afford an Offeror who is engaging in the uneconomic investment additional

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[14] For example, one New Jersey proposal included a 15-year contract that would artificially suppress prices. S. No. 2381, 214th Leg., First Reprint (Nov. 15, 2010). In the discussion of New Jersey's proposed exercise of buyer market power, the Independent Market Monitor noted that 1,000 MW of uneconomic entry would depress prices by $1 billion per year. IMM Analysis at 1. The total contract payments under the New Jersey proposal over 15 years had a nominal cost of approximately $1.27 billion, allowing a market wide payback of about 15 months.

opportunities to reduce his overall costs of price suppression activities. The combined impact is that in reality even a year of exclusion doesn't occur.

Q WHAT IS THE FOURTH FLAW YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A The fourth major failing of the current Minimum Offer Price Rule is that it is full of limitations, loopholes and exemptions that are easily gamed to permit the exercise of buyer market power. All of these loopholes should be closed. I focus on three: the exemptions for net buyers of capacity, self-supply, and Planned Generation Capacity Resources, but counsel has identified others and they too should be closed.

Q WHAT IS THE EXEMPTION RELATED TO NET BUYERS OF CAPACITY?

A The Minimum Offer Price Rule conduct screen applies only to net buyers of capacity. In theory, with no market concentration and atomistic supply and demand, it could make sense to waive the mitigation offer floor in situations where the party offering the new supply is not a net buyer in the markets. With no purchases being made at the market price, there is no benefit to suppressing the price. But perfect competitive conditions do not exist, and, as a result, what appears to be a simple screening rule is not simple at all and can easily be circumvented.

Q HOW DOES REQUIRING THAT THE OFFEROR BE A NET BUYER PREVENT THE MINIMUM OFFER PRICE RULE FROM LIMITING BUYER MARKET POWER?

A The inefficiency of such a rule is easily seen in the current actions of the New Jersey legislature with respect to the PJM RPM markets.[15] The New Jersey legislature has

[15] S. No. 2381, 214th Leg. (N.J. 2011), attached as P3 Exhibit 2 to the Complaint.

passed legislation that, for all practical purposes, attempts to circumvent the net buyer requirement of the Minimum Offer Price Rule. The legislation subsidizes 2,000 MW of *new* generation. Existing generation is ineligible, i.e., it is explicitly discriminatory. The legislation directs those receiving the subsidies to bid in such a manner as to clear in the PJM Base Residual Auctions (i.e., subsidy recipients must offer so as to assure being accepted). The legislation creates agreements between a seller and the state regulated distribution companies (which are Load Serving Entities). In these agreements, payments are made via a contract for differences to the third party that owns the generation.[16] The contract for differences is designed to assure guaranteed revenues to the new generation regardless of the market price.

The legislation effectively sets up a situation in which a seller only owns the subsidized generation and typically would not fall within the definition of net buyer. The seller is acting as an agent of the state, and the state represents buyers. Payments for the contracts are supported by a non-bypassable surcharge on all customers. The state, in this example, is the actual net buyer of capacity, but the state does not submit the bids into the auction.[17] The winning bidder, whose only asset might be the new generation, thus may escape mitigation. Because legislation like the New Jersey proposed statute is intended to circumvent the Minimum Offer Price Rule, the Minimum Offer Price Rule is

[16] Under a contract for differences, there would be an agreed contract fixed price. The Seller would sell into the market directly and receive market rates (thus being a net seller). If the auction clearing rate is higher than the fixed price in the contract, the seller pays the difference to the buyer; if the auction clearing rate is lower, the buyer pays the seller the difference.

[17] I take no legal position with respect to whether this approach to the exercise of market power falls within the scope of the existing Minimum Offer Price Rule. Both PJM and the Independent Market Monitor have explicitly taken the view that regardless of any such determination, it should. *See* Letter from Andrew L. Ott, Senior Vice President, Markets, PJM Interconnection and Dr. Joseph E. Bowring, President, Monitoring Analytics to Lee A. Solomon, President, New Jersey Board of Public Utilities (Dec. 3, 2010), http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM-MMU_Letter_to_NJ_BPU_20101203.pdf ("Bowring Letter"). Their concern suggests that they too recognize this potential limitation or ability to circumvent the current rule.

ineffective in actually limiting buyer market power. I discuss the New Jersey example in greater detail below.

Q HAS THE COMMISSION RECOGNIZED THIS BASIC FLAW WITH THE USE OF A NET BUYER SCREEN FOR MITIGATION?

A Yes, it did in the recent NYISO Order. In addressing the NYISO's mitigation process the Commission stated that NYISO:

> . . . will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. *We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address*. Parties requesting rehearing have convinced us that defining net buyers raises significant complications and provides undesirable incentives for parties to evade mitigation measures. Accordingly, we grant rehearing on this issue . . . .[18]

Q ARE THERE ANY OTHER PROBLEMS WITH THE CURRENT MOPR'S NET BUYER SCREEN?

A Yes. Regardless of the net buyer conduct test discussed above, the threshold related to establishing a net buyer for small locational delivery areas in the current Minimum Offer Price Rule is too high.

Q HOW DOES HAVING A HIGH THRESHOLD FOR SMALL LOCATIONAL DELIVERY AREAS PREVENT THE MINIMUM OFFER PRICE RULE FROM LIMITING BUYER MARKET POWER?

A Having a high threshold for small locational delivery areas allows for the exercise of buyer market power regardless of whether an accurate determination of net buyer status (without manipulation) can be obtained. This is seen by looking at an example using the

[18] *N.Y. Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 29 (emphasis added).

10% criterion for a locational delivery area of under 10,000 MW. Assume that the local reliability requirement of a locational delivery area is 9,500 MW, and it is served by a single Load Serving Entity with a 10% net short position, or that, in other words, was a net buyer of 950 MW. The conduct threshold would not be triggered in such a situation.

Now consider the impact of such a Load Serving Entity purchasing 380 MW of unneeded/uneconomic capacity (i.e., 4% of the locational delivery area reliability requirement). Using the approximately $260 per MW-day net Cost of New Entry values for PJM Eastern MAAC from the last Base Residual Auction, assume that $260 per MW-day net Cost of New Entry was the clearing price without any manipulation. Assume also that any resulting price suppression caused by adding 380 MW to the Load Serving Entity kept the locational delivery area price separated from the rest of the Regional Transmission Organization. The result in this simplified example would be that the clearing price would decline 80%, from $260 to $52 per MW-day. The price suppression works for a net benefit of approximately $36 million per year after accounting for the cost of the uneconomic entry.[19]

Clearly, the 10% threshold in a small locational delivery area is an ineffective screen. If the screen is interpreted to be simply 10% of a gross position, and other Load Serving Entities held some of the "hedged" existing facilities, the benefit for exercising market power would actually be higher because other Load Serving Entities would purchase some of the uneconomic generation at the low market price, but still would offset some of the costs incurred by the Load Serving Entity exercising market power.

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[19] The gross savings are $72,124,000 (950 MW x 365 days x $208 per MW-day =$72,124,000), and the net cost of the uneconomic entry here is $36,062,000 (380 MW x 365 days x $260 per MW-day = $36,062,000), for an annual net savings of $36,062,000.

Q WHAT IS THE NEXT EXEMPTION THAT YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A The next material exemption in the Minimum Offer Price Rule that I identified as problematic is that it appears to completely ignore self-supply. Depending on an interpretation of the term "Planned Generation Unit," and what constitutes a Sell Offer, a buyer may be able to successfully avoid mitigation by simply designating an uneconomic unit as self-supply.

Q HOW DOES IGNORING SELF-SUPPLY PREVENT THE MINIMUM OFFER PRICE RULE FROM LIMITING BUYER MARKET POWER?

A The omission of self-supply from the Minimum Offer Price Rule is a particularly troubling omission given two basic elements of the PJM capacity market. First, there is no inconvenience cost associated with simply bidding in self-supply as a price taker in the auction when the capacity is economic and should not be subject to mitigation. This is what is happening now, without the separate designation of self-supply.

Second, PJM, at least at a macro level, already provides for zones and other limited loads to opt-out of the RPM process to serve their capacity needs. If a state truly is concerned with reliability and not price manipulation, it can avail itself of this alternative to assure reliability under its own criteria without distorting prices market-wide. The Fixed Resource Requirement option allows parties, such as New Jersey, who might think their reliability needs are not being properly addressed by the RPM process, to effectively remove both their load and generation from the RPM market. In doing so, the party is responsible for meeting its own requirements and is subject to certain limitations with respect to purchases and sales with the rest of PJM. By opting for the

Fixed Resource Requirement option, of course, the party would lose the ability to manipulate market prices for the entire PJM footprint through out-of-market support of uneconomic entry. Presumably the party would also have to pay just and reasonable prices to their own internal supply.

Q WHAT IS THE NEXT EXEMPTION THAT YOU IDENTIFIED IN THE MINIMUM OFFER PRICE RULE?

A The next exemption that I identified in the Minimum Offer Price Rule is that it only applies to a limited subset of Planned Generation Capacity Resources. In general a Planned Resource, as defined in the Reliability Assurance Agreement, refers to any resource entered in the interconnection process that passes certain milestones. A Planned Generation Capacity Resource remains "Planned" until it becomes operational and takes interconnection service.

The Minimum Offer Price Rule, however, does not use this definition independently, but rather modifies its use in a fashion that limits its applicability and undermines the ability to mitigate buyer market power. In section 5.14(h)(2), the Minimum Offer Price Rule states that it applies only to "[a]ny Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, in any locational delivery area for which a separate Variable Resource Requirement Curve has been established . . . ." Thus, the universe of Planned Generation Capacity Resources to which the Minimum Offer Price Rule could apply is severely limited.

Q HOW DOES THE LIMITED APPLICATION OF THE MINIMUM OFFER PRICE RULE TO PLANNED GENERATION CAPACITY RESOURCES PREVENT IT FROM LIMITING BUYER MARKET POWER?

A This limitation effectively cancels the applicability of the Minimum Offer Price Rule to any new resource. To fully avoid the application of the Minimum Offer Price Rule, all a party needs to do is to submit a schedule for its resource that identifies a commencement date one year earlier than actually anticipated, and then bid a "high" price in the related auction.[20] There is no penalty for commencing operations late. Thus, after failing to clear once, the party's unit is no longer subject to mitigation under the Minimum Offer Price Rule and the party could offer the unit at any price (including zero) in subsequent auctions without any adverse consequence. In fact, the party could offer the unit as a price taker in the very next Base Residual Auction. Because a party can easily game the entire system, the mitigation approach used in the Minimum Offer Price Rule is toothless.

And, as set forth above in my third identified flaw, if not fully bypassed by this false commencement date scheme, the mitigation itself nevertheless remains too brief, applying only to a single Base Residual Auction and thereafter to none of the incremental auctions. It is easy to imagine someone procuring a "string" of uneconomic new entry staged to enter the market over time in order to exploit this weakness. In sum, the Minimum Offer Price Rule is completely ineffective at actually limiting any buyer market power.

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[20] While in general Sell Offers for new resources are not capped, some limitations apply. However, in the context of a party trying to suppress prices, a premature offer at the highest possible cap is unlikely to ever clear, as the entire strategy revolves around offering excess capacity to artificially drive prices below the Cost of New Entry, an environment where pricing would presumably be below the Cost of New Entry.

B. The Minimum Offer Price Rule's Flaws Are Easily Exploited

Q ARE THE FLAWS IN THE MINIMUM OFFER PRICE RULE EASY TO EXPLOIT?

A Yes. A recent example is New Jersey's new legislation to sponsor uneconomic entry, and it apparently will soon be followed by similar actions in Maryland. Though these schemes have not yet been fully implemented, they are clear signs that the rule is vulnerable.

Q ARE THERE INDICATIONS THAT THE NEW JERSEY LEGISLATION IS DIRECTED AT CIRCUMVENTING THE MOPR AND SUPPORTING UNECONOMIC GENERATION?

A Yes. The Independent Market Monitor explicitly expressed its concern that the legislation might be an attempt to evade the Minimum Offer Price Rule's applicability.[21] PJM even warned the New Jersey Board of Public Utilities that regardless of any express language, it would choose to interpret the Minimum Offer Price Rule as still applying in situations where there is clearly an intent to circumvent its application.

Moreover, based on the analysis that has gone into the legislation, there is little doubt here that price suppression is a major motivation for the state-directed procurement. While the preamble to the bill does discuss reliability, the requirements of the legislation do not link the new generation to any specific reliability constraint or specific need or study result. Further, there was absolutely no indication of any analyses related to the cost effectiveness of a state-directed procurement on a stand-alone basis versus prices and resources available from the market under the existing RPM auction process. In other words, no one ever compared the cost of the resources being given a

[21] *See* Bowring Letter.

contractual payment floor to the current or expected market prices. It is hard to imagine a more fundamental omission.

Thus, there was and is no research as to whether the proposed New Jersey plan is cost justified—i.e., whether the proposal is more efficient than simply procuring generation from existing resources at the market prices. In sensitivity studies conducted by PJM on the 2010 Base Residual Auction results, prices in the EMAAC LDA would have dropped from about $245 per MW-day to approximately $100 per MW-day upon completion of several of the transmission facilities approved in the PJM transmission expansion plan. This indicates a lack of long-term need for new entry to maintain reliability.[22]

Q IS THERE ANY INDICATION THAT NEW JERSEY IS EXPERIENCING A SHORTAGE OF GENERATION RESOURCES?

A No. Prices in recent years have been near or well below the Reference Resource's Net Cost of New Entry, and on the demand curve that price point is set at the local reliability target. Thus, there is no indication of any reliability problem. This indicates that more capacity is being procured than the reliability target requirements.[23] Similarly, PJM provided comments to the New Jersey Board of Public Utilities indicating that reliability targets were being met.[24] PJM explicitly plans to add necessary transmission reinforcements on a mandatory basis should it identify potential reliability problems in

[22] *See* PJM, Scenario Analysis Results, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/scenario-analysis-results.ashx, attached hereto at P3 Exhibit 1-B ("PJM Sensitivity Studies").

[23] *See* Statement of Roy J. Shanker, Ph.D. on behalf of Competitive Suppliers Coalition, Statement before the N.J. Senate Environment and Energy Committee, at 12 tbl.A (Nov. 15, 2010 & Dec. 9, 2010), attached hereto at P3 Exhibit 1-C (showing recent capacity clearing amounts versus requirements for relevant localities).

[24] *In re N.J. Bd. of Pub. Utils. Review of State's Elec. Power & Capacity Needs*, No. EO09110920, Comments of the PJM Interconnection, LLC (N.J.B.P.U. July 6, 2010).

any locational delivery area. As stated above, major planned transmission facilities will also significantly increase capacity deliverability into the area (the Susquehanna-Roseland line, PATH and MAPP). Indeed, one of the major benefits of the RPM design is that prices will rise as the need for new transmission increases and the system approaches the online date of the new transmission facilities, thereby encouraging both the retention of economic existing resources as well as new entry. But in the overall PJM market design, transmission additions will "lead" generation into constrained localities, limiting the need for new generation in a locational delivery area until the system as a whole approaches its reliability targets.

Further, what is equally telling is the fact that many "experts" in the electric industry in New Jersey have been actively litigating a position where they represent that PJM reliability standards are too strict, and that PJM's current policies overstate the need for new generation.[25] This includes the New Jersey Board of Public Utilities and the New Jersey Division of the Rate Counsel. It is paradoxical that these same parties are also urging the subsidy of new generation. Clearly the positions are inconsistent—unless their motivation behind adding new capacity is actually to suppress prices.

Finally, new generation and entry are possible today in New Jersey when the price is right. Currently there are over 900 MW of capacity exports from the region via transmission ties, and approximately 1200 MW of generation is sited physically in New Jersey but electrically chose to interconnect to New York City, with 500 MW of that currently under construction. At minimum, the transmission line exports would be

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[25] *See Md. Pub. Serv. Comm'n v. PJM Interconnection*, 124 FERC ¶ 61,276 (2008), *reh'g denied*, 127 FERC ¶ 61,274, *appeal docketed sub nom. Md. Pub. Serv. Comm'n v. FERC*, D.C. Cir. No. 09-1296 (filed Aug. 14, 2009) (oral argument held Nov. 15, 2010).

expected to reverse if scarcity and market prices indicated a need in New Jersey. Additionally PJM identified approximately 850 MW of new capacity and approximately 1500 MW of demand response added to New Jersey under RPM.[26]

Q WHY WOULD NEW JERSEY SPONSOR UNECONOMIC ENTRY?

A The PJM market is designed such that clearing prices less than nominal levelized net Cost of New Entry indicate a surplus of supply over the target reliability level. Thus the fact that New Jersey is proposing above-market subsidized prices is a *de facto* indicator that there is no need for the proposed facilities. Instead, the legislation is merely a means of exercising buyer market power.

Instead of examining whether the proposal is efficient, the only considerations made by New Jersey were the price suppressing effects of the procurement of unneeded capacity. Presentations by LS Power indicate that it believes energy prices as a whole may be depressed by $98 million per year under the proposed legislation simply from an addition of only 650 MW of uneconomic supply.[27] This was not a measure of improvements of efficiency or reduction in production costs. It simply measured shifts in revenues caused by adding excess supply. Similarly, the New Jersey Rate Counsel submitted recent comments to the New Jersey Board of Public Utilities estimating that capacity prices would be suppressed on the order of $465 million per year by adding 500 MW of otherwise unneeded capacity.[28] These alleged "savings," however, are not true

[26] *See In re N.J. Bd. of Pub. Utils. Review of State's Elec. Power & Capacity Needs*, No. EO09110920, Presentation at Technical Conference, New Jersey Power Supply Load and Capacity Data at 14-16 (June 24, 2010), http://www.state.nj.us/bpu/pdf/energy/HERLING%20AND%20KORMOS.pdf.

[27] LS Power, New In-State Generation, LS Power Energy Savings Analysis at 11 (Nov. 2010), attached hereto at P3 Exhibit 1-D.

[28] *In re N.J. Bd. of Pub. Utils. Review of State's Elec. Power & Capacity Needs*, No. EO09110920, Comments of the Division of Rate Counsel at 8 (N.J.B.P.U. July 2, 2010).

savings; they are simply wealth transfers from unsubsidized, competitive sellers to buyers, realized through the exercise of buyer market power.

The key observation here is that no one ever considered the underlying economics of the transaction; they only considered the benefits of price suppression. Indeed, the New Jersey Rate Counsel sees the legislation as a win/win proposition for just this reason. In related testimony before the state legislature, the Rate Counsel justified the subsidized contract solely on the basis of its price suppressing effect. The Rate Counsel conducted analyses, estimating the price suppression at $50 per MW-day, which would in this case apply to all of EMAAC, or 33,000 MW. The Rate Counsel also noted that should the capacity actually be needed, it would then be a really good deal, as then the price of the contract would be "in the money." But the Rate Counsel never considered evaluating the possibility of there actually being a real stand-alone economic justification for the contracts, or whether the contract was "in the money." The price suppression effect was all that was of interest.[29]

Q ARE THERE OTHER WAYS THAT THE NEW JERSEY LEGISLATION TAKES ADVANTAGE OF THE CURRENT MINIMUM OFFER PRICE RULE?

A Yes. The New Jersey legislation also exposes the second flaw that I identified above regarding the impact thresholds for mitigation to be triggered. The ineffectiveness of the current impact threshold is not speculative. The Independent Market Monitor re-ran the 2013-14 auction results, for example, to include 1,000 MW of uneconomic entry (a level that the New Jersey legislation had previously proposed). That level of uneconomic entry

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[29] *See* Stefanie A. Brand, Remarks Regarding A3442, Presented at the Assembly Telecommunications and Utilities Committee Meeting (Dec. 16, 2010), http://www.state.nj.us/rpa/docs/Remarks_of_Stefanie_Brand_A3442-Electric_Generation_Facilities.pdf.

would have *barely* failed the impact screen, suppressing prices from $245 to $191 per MW-day, or slightly more than the 20%. The total cumulative annual impact would have been $1 billion.[30] PJM itself prepared sensitivity runs looking at an additional 1,000 MW added in the EMAAC LDA at zero cost, and concluded that the revised price would be $195.33 per MW-day, again just slightly more than 20%.[31]

Assuming the impact is roughly linear, and conservatively using the Independent Market Monitor's results, this means that if a party seeking to exercise buyer market power fine-tuned its analysis, and added only 940 MW in one year instead of 1,000 MW, the suppression would *only* be $49 per MW-day, the impact test would be passed, and there would be no mitigation. This means that a cumulative market-wide impact of approximately $940 million per year would go unchecked.

While the current legislation is for 2,000 MW, it will be spread over multiple years, which will also easily allow the impact threshold to be sidestepped. This could happen even though the PJM Independent Market Monitor determined an annualized price suppression of $2.16 billion for the market as a whole if the entire 2,000 MW were added, based on the last auction results.[32]

Absent a change in the Minimum Offer Price Rule by the Commission, New Jersey or others could easily fine-tune their proposals to achieve just this result. Yet it seems impossible (or at least disingenuous) to assert that a market mitigation rule that allows almost $1 billion a year in anti-competitive revenue transfers is just and reasonable. And the impact of uneconomic entry could easily be staggered or phased to

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[30] *See* IMM Analysis at 2-4 & tbl.1.

[31] *See* PJM Sensitivity Studies.

[32] IMM Analysis at 2-4 & tbl.6.

ensure that the impact screen is never failed. If spread over two or three years, even an impact of $2.16 billion could be deemed too insignificant to be mitigated under the current rule.[33]

Q ARE THERE ANY INDICATIONS THAT OTHER STATES MAY BE TAKING SIMILAR ACTIONS?

A Yes. The Maryland Public Service Commission recently sent out a draft Request for Proposal for comment. The Request for Proposal was for new electric generation facilities in and around Maryland and included consideration of a new mandate that would require electric distribution companies under the Maryland Public Service Commission's jurisdiction to enter into long-term contracts to build new resources.[34] Up to 1,800 MWs may be procured, but it would all be required to be new generation and to offer into the RPM auctions so as to assure that the capacity clears. As noted earlier, this is exactly the "formula" approach to the exercise of buyer market power by a state or regulatory authority.[35]

On January 28, 2011, the PJM Independent Market Monitor submitted comments in response to the Maryland Public Service Commission that summarized the joint impact of the New Jersey and Maryland actions, noting a combined price suppression of more than $3 billion per year based on recent auction results.[36]

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[33] These impacts would be for the first year of addition and would decline over time, assuming that there is no further exercise of buyer market power. However, given the obvious paybacks, it would make sense to continue with uneconomic additions continually over time.

[34] *See generally In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv.*, No. 9214, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (M.P.S.C. Dec. 29, 2010).

[35] *Supra* at 15:4–16:2.

[36] *See In the Matter of Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Serv.*, No. 9214, Comments of the Independent Market Monitor for PJM at 4 (M.P.S.C. Jan. 28, 2011),

Q IS THERE ANY OTHER EVIDENCE THAT THIS TYPE OF MARKET SUPPRESSION INCREASES COSTS?

A Yes, and immediately so. I would expect distortions of consumption to begin immediately, thereby harming efficiency. I would expect the cost impacts to be spread more over time, but it appears that serious cost impacts have already begun. According to the January 28th release of Megawatt Daily (dated Jan 31, 2011), in an article on the likely impact of New Jersey's legislation, "Moody's said the potential in the long term is for the bill to be a material credit negative primarily to the unregulated power sector within New Jersey." As it turns out, this statement turned out to be issued on the same day that the New Jersey Governor signed the bill. I would expect markets to immediately react to these types of comments, driving down the value of stock and debt in the unregulated power sector, and in turn increasing the costs of funds to investors in electric utility infrastructure.

Q WHAT CONCLUSIONS ABOUT THE MINIMUM OFFER PRICE RULE DO YOU DRAW FROM NEW JERSEY'S AND MARYLAND'S ACTIONS?

A The conclusion here is clear: because a state legislature or state commission can effectively vitiate the Minimum Offer Price Rule and allow the exercise of buyer market power, the Minimum Offer Price Rule is unjust and unreasonable.

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http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf.

Q WHY DOES A STATE LEGISLATURE'S OR STATE COMMISSION'S ABILITY TO CIRCUMVENT THE MINIMUM OFFER PRICE RULE RENDER IT UNJUST AND UNREASONABLE?

A The New Jersey legislation and the Maryland Request for Proposal demonstrate that bypassing the Minimum Offer Price Rule is easy. In both cases, all that was necessary to potentially bypass the Rule was to establish contracts for differences via a proxy. In a sense, it was so easy to bypass the rule that the process was done in an open and notorious manner, almost flaunting the tariff. As noted above, PJM recognized this potential deficiency in the Minimum Offer Price Rule and notified the New Jersey Board of Public Utilities that it would take the position that such out-of-market purchases of uneconomic capacity, in the proposed proxy fashion, would be deemed actions by a net buyer regardless of the language of the Rule. But there should not be any doubt that such behavior violates the purpose of the Rule and must be mitigated.[37] The rule should be modified so that it is certain to fully mitigate uneconomic entry.

While my intent is not to give a tutorial on how to bypass the Rule, it should be relatively transparent that a wide range of proxy arrangements, side payments, out-of-market contracts and other tools—many of which are far less visible and much harder to detect than state legislative actions or mandated state regulatory orders—can have the exact same impact, thereby rendering the Minimum Offer Price Rule entirely toothless.

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[37] *See* Bowring Letter.

III. RECOMMENDED SOLUTIONS TO FIX THE MINIMUM OFFER PRICE RULE

Q HAVE YOU IDENTIFIED AN ALTERNATIVE TO THE MOPR THAT WOULD RESOLVE THE FLAWS YOU IDENTIFIED AND PROVIDE FOR THE EFFECTIVE MITIGATION OF BUYER-SIDE MARKET POWER?

A Yes. In doing so, I have tried both to incorporate recent Commission precedent on the issue of buyer-side mitigation, and at the same time identify a mitigation approach that can incorporate and take advantage of the specific market characteristics of the three year lead time utilized in the PJM Base Residual Auction.

This leads to a partitioning of the mitigation approach between:

(1) longer-lead-time units, where mitigation is still needed, but by definition has to be based on longer-lead-time assumptions regarding the economics and market projections of the resource at the time of commitment; and

(2) shorter-lead-time units, where it is possible to incorporate the market test of the RPM Base Residual Auction as part of the conduct screen to determine whether mitigation is needed.

Q WHAT SPECIAL CONSIDERATIONS APPLY TO LONGER-LEAD-TIME UNITS?

A For longer-lead-time units, it is important that market participants not be caught in a situation of having made a rational business decision at the time of commitment to essentially begin construction, only to subsequently find themselves subject to mitigation. This could happen if circumstances changed between the time of commitment and the first eligible Base Residual Auction.

Providing developers of long-lead-time units with assurances regarding the mitigation status of their units before they commit to proceed with construction requires some care. There will be a degree of substitution of the business decision-making of developers for decision-making by either or both PJM and the Independent Market Monitor.

Q DOES THIS ISSUE APPLY TO SHORTER-LEAD-TIME UNITS?

A No. For shorter-lead-time units, this concern can effectively be ignored. Mitigation can instead be focused on behavior in the Base Residual Auction because the shorter-lead-time unit can be built within the three-year window between the auction and delivery. Offers will be mitigated if they are uneconomic, but the project will know before construction begins whether it will be subject to the mitigation of its Sell Offer in the capacity market auctions. Further, any project (long- or short-lead-time) that can demonstrate it has not received discriminatory benefits will be free from all mitigation. This allows market participants with legitimate, unsubsidized short-term projects to exercise their own private business decision-making, independent of the expectations of PJM or the Independent Market Monitor.

Preserving this private decision-making is an important element of maintaining the viability of competitive markets and market solutions. To the extent this can be done, while also protecting the market against the anti-competitive and discriminatory impacts of buyer market power, it is a reasonable objective. I believe the bifurcated approach I describe below has exactly this property. Imposing mitigation decision-making over private business decisions is minimized where possible, while robust mitigation is maintained.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED MITIGATION FOR LONG-LEAD-TIME-UNITS?

A My approach here for long-lead-time new resources stems from the Commission's recent decision in the NYISO in-city capacity market. The Commission issued an order[38] that

[38] *N.Y. Indep. Sys. Operator, Inc.*, 133 FERC ¶ 61,178 (2010), *reh'g pending*.

addressed and basically accepted as filed the NYISO's modified and refined capacity buyer-side mitigation measures. It is possible to use provisions that were approved in this recent decision that address the very weaknesses identified above. This would reform the Minimum Offer Price Rule so that it truly has the potential to deter uneconomic entry. I believe the NYISO in-city mitigation is an excellent building block, particularly for units that have to enter into commitments to proceed with development prior to the existing Base Residual Auction horizon.

Q BRIEFLY SUMMARIZE THE NYISO CAPACITY MARKET DESIGN AND HOW IT COMPARES TO PJM.

A The NYISO capacity market clears from 6-month strip auctions to monthly spot auctions, while PJM is an annual auction conducted three years in advance. Though the time steps are different, the basic market design principles in PJM and NYISO are the same. The NYISO capacity market is built around a clearing auction utilizing a demand curve. NYISO's demand curve is completely linear, unlike PJM's shaped linear segments. NYISO's demand curve has a fixed point at the net cost of new entry and at the target reliability requirement of the installed reserve margin. In PJM the analogous points on the curve are the net cost of new entry but the target requirement for the system as a whole is set at installed reserve margin plus 1%. The NYISO market is locational, as is PJM, and there are different slopes to the demand curve and different net Cost of New Entry values for each of the current three localities in New York: New York City, Long Island and everywhere else ("NYCA"). PJM maintains a similar shape for the locational delivery area curves, but adjusts for different net Costs of New Entry. The clearing "engines" in each market are slightly different, but each solves for the necessary locational requirements and the overall market requirements as a whole.

For exactly the same reasons as PJM, NYISO instituted market mitigation measures for the New York City locality to prevent price discrimination and suppression by uneconomic new entry. This was clearly needed due to a very high concentration of buyers and their associated ability to transfer potential out-of-market payments via non-bypassable charges, typically via retail rate charges. Though the intent was similar, the current NYISO design, reflecting the refinements of the current order, is superior in most respects[39] to the PJM Minimum Offer Price Rule, and avoids most if not all of the Minimum Offer Price Rule's failings. In many ways, NYISO's approach is the same as the Minimum Offer Price Rule, just "fixed."

Q PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF NYISO'S CAPACITY BUYER-SIDE MITIGATION.

A The NYISO rule has a similar conduct and impact structure to the Minimum Offer Price Rule. It has no net buyer exception, however, as the Commission rejected it. All new Sell Offers in New York City are reviewed regardless of the market position of the seller.[40]

There is a market-based conduct screen with respect to any Sell Offer from a new facility. In the terminology used above, a new Sell Offer fails the conduct screen if it is below 75% of the net Cost of New Entry. Any new Sell Offer is mitigated to this level

[39] I discuss below the major exception I propose in PJM regarding the conduct and "mitigate-to" levels. Given the materially different competitive environments, I concluded that these levels should be set at 100% at minimum in PJM, versus the 75% used on the NYC market where there is limited competitive entry and highly concentrated demand.

[40] The only exceptions are certain "Special Case Resources," which are certain interruptible end-use loads and distributed generators.

(or its own demonstrated unit cost, calculated in the same way that the net Cost of New Entry is calculated)[41] unless the NYISO determines that the new facility would be anticipated to clear the market at its Sell Offer. This determination is based on a forecast prepared by the NYISO of market conditions expected at the time of entry.[42] The forecast is prepared at the time the new entrant has to decide whether or not to enter into an Interconnection Service Agreement, and commit to associated network upgrades. If the new Sell Offer is forecasted to clear the market, effectively the new unit is deemed to have passed the conduct screen and will not be subject to mitigation. Thus, it may offer into the market at its Avoidable Cost Rate or less when it commences operation.

If, on the other hand, the new facility fails the conduct test (i.e., it is found not to be anticipated to be economic), then it is subject to mitigation and its offer price will be set at a floor level until the capacity clears in actual auctions. The floor level is equal to the lesser of 75% of the reference net Cost of New Entry or the Unit Cost of New Entry for the new entrant. Presumably with this information it may choose not to proceed. The clearing determination is "divisible," that is, if a portion—for example, 40%—of a unit clears for a sufficient period, then that 40% would be no longer subject to mitigation at a floor price, and only the remaining 60% would be subject to offering at the specified floor price.

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[41] The specific levelized calculation of the unit specific net cost of entry is determined in a fashion that is parallel to the methodology that the NYISO has adopted in its demand curve reset process for the determination of gross and net Cost of New Entry.

[42] As modified all new entrants in a "class year" would be evaluated simultaneously for a period three years in the future.

Q WHY DO YOU FOCUS ON THIS APPROACH FOR LONGER-LEAD-TIME NEW ENTRANTS IN THE CAPACITY MARKET?

A Because by its very nature the NYISO approach is a forecast-based procedure, with commitments to new units occurring well before the monthly time-step of the NYISO market. If mitigation were applied at the time the new entrant actually could participate in the seasonal or monthly market, the participant would be faced with the dilemma of having to build a new unit without knowing if it might be mitigated because of changes in market circumstances, regardless of the genesis of those changes. If mitigated, the new resource might not clear in the capacity market after the unit was fully constructed. This is directly analogous to long-lead-time units outside the RPM Base Residual Auction window in PJM. As discussed further below, however, it is unnecessary for shorter-lead-time units.

Q PLEASE IDENTIFY THE SPECIFIC ELEMENTS OF THE NYISO IN-CITY CAPACITY BUYER-SIDE MITIGATION THAT RESOLVE THE DEFICIENCIES OF THE MINIMUM OFFER PRICE RULE FOR LONG-LEAD-TIME UNITS.

A There are three specific items:

1—*All* new entry (other than Special Case Resources) is subject to screening for market power and mitigated to an appropriate offer floor if deemed to be uneconomic. The conduct screen basically establishes whether, at the time a commitment to proceed with the unit is made, a rational decision maker would find the unit to be economic as compared with a forecast of expected market outcomes. There are no exceptions to mitigation for being a net buyer and only Special Case Resources are exempted. There is no exclusion for self-supply.

2—If the initial conduct evaluation is failed, the offer is mitigated. There is no subsequent impact threshold other than the offer floor; the unit either clears or remains mitigated.

3—There is no limit on duration for uneconomic supplies being mitigated. Units determined to be uneconomic remain constrained to offer at their mitigated price until they clear the market for a sufficient period to be deemed economic.

With this foundation in mind, I now proceed to my recommended changes to the Minimum Offer Price Rule.

Q WHAT CONDUCT SCREENS DO YOU RECOMMEND FOR LONG-LEAD-TIME UNITS?

A The conduct screens that I recommend each review the offer to determine whether it will be economic at the proposed time of new entry. This is similar to the conduct screen used in the NYISO In City capacity mitigation. The nominal levelized Unit Specific Net Cost of New Entry would be reviewed to determine whether it would be economic and clear two Base Residual Auctions. If so, the unit would not be mitigated when ultimately it becomes operational. If the long-lead-time unit is not forecast to clear, and the party chooses to proceed with construction anyway, its capacity Sell Offers would be mitigated to its forecasted Unit Specific Net Cost of New Entry until the unit cleared in two auctions.

The evaluation of whether a long-lead-time unit is forecast to clear the market would be based on a demonstrated nominal levelized Unit Specific Net Cost of New Entry. This would be calculated in a similar manner to that currently used by PJM and the Independent Market Monitor to make such determinations for the Reference

Resource. If the new entrant is deemed to clear for such a period, then its offers in the capacity market when the unit actually commences operations would not be mitigated, and it could offer into the market up to its then applicable Avoidable Cost Rate as determined in accordance with the existing tariff.[43]

This allows for a clean, bright-line evaluation of all new entry. If at the time of the execution of an Interconnection Service Agreement, it is deemed rational to proceed with the new facility, then regardless of subsequent actual events and prices, the new entrant would not be mitigated. If deemed uneconomic, the party could still proceed, but would face mitigation. This decision is prior to actually commencing construction or signing the Interconnection Service Agreement.

This allows for a party to proceed with certainty regarding the status of its unit when it enters the market, and avoids future second guessing regarding what constitutes economic entry. Further, to the extent that a unit is mitigated, and actual prices turn out to be higher than forecasted, the application of this criteria is self correcting, as the new unit at the mitigated prices would then likely clear, be determined to be economic, and then subsequently have the mitigated offer floor removed.[44] As mentioned, any unit that can demonstrate it does not receive any discriminatory benefits is fully exempt from mitigation.

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[43] See revised tariff language at Attachment A to the Complaint.

[44] It can be argued that this type of determination could be made repeatedly, even after the Interconnection Service Agreement is executed, to assess whether it is still rational to proceed with the new unit. However, at the time a resource commits to PJM to build necessary transmission upgrades, which will be built regardless, it seems that this is a reasonable point to consider the unit "committed," and to provide it with certainty regarding mitigation.

Q WHY DO YOU NOT RECOMMEND THAT THIS SAME SCREEN BE APPLIED TO SHORT-LEAD-TIME RESOURCES?

A Unlike the situation in NYISO where commitments to proceed with new capacity must be made prior to the actual auction, in PJM it is possible to first test the economics of a new facility in the auction. There, a new resource can determine the need for new unit prior to building it. By definition, a short-lead-time unit can be built within the three-year window between the auction and the delivery year. This means that mitigation can focus on the actual behavior of the new entrant. At the time of the auction, it can be determined whether the new entrant is receiving out-of-market support or other types of discriminatory payments that may be covered by non-bypassable charges through the "real" project sponsor or beneficiaries of uneconomic entry. As a result a reasonably straightforward mitigation approach for short-lead-time units can be implemented that addresses uneconomic entry without the need to substitute a forecast by PJM or the Independent Market Monitor for the business discretion of the project sponsor.

Q WHAT CONDUCT SCREEN DO YOU PROPOSE FOR SHORT-LEAD-TIME UNITS, INCLUDING COMBUSTION TURBINES AND COMBINED CYCLES?

A Subject to the exceptions noted below, any resource—and, in particular, short-lead units—would pass the conduct screen if its bid is at least 100 percent of the net cost of new entry of the Reference Resource (a combustion turbine as defined in Attachment DD of the PJM tariff, section 2.58). If it offers below 100 percent of its benchmark, the conduct screen is failed.

Q ARE THERE ANY OTHER WAYS TO PASS THE CONDUCT SCREEN?

A Yes. A safe harbor will be created for any new entrant that can demonstrate conclusively and warrant that it has not and will not be the beneficiary, directly or indirectly of any out-of-market payments. This is the same as for long-lead time units. A discriminatory or out-of-market payment is any payment, direct or indirect, that is not available to other market participants, but is principally only available to new entry. Thus a payment is discriminatory or out-of-market if it results from an auction or request for proposals for new entry and excludes existing resources. A bilateral agreement for new entry, or a more general bilateral agreement—like a futures agreement—is also discriminatory or out-of-market if priced above market and in support of a portfolio that includes new entry. It does not matter if the payment is directly to the project or to an affiliate or third party. Rate-based recovery for a new resource is also discriminatory and out-of-market.

If, on the other hand, a payment is not contingent upon a resource being new, there is a good chance it is not discriminatory.

To show its payments are not discriminatory or out-of-market, the new entrant would have to provide the Independent Market Monitor or PJM with sufficient information to allow a determination of whether the new entrant, its owners or affiliated entities are the beneficiaries of any discriminatory payments or other out-of-market benefits that may be recovered via some non-bypassable mechanism such as distribution company tariffs, state taxes or similar mechanisms. Such information would have to be provided with a sufficient level of detail so that mechanisms like contracts for differences or other contract payments and arrangements via third parties would all be disclosed. Further, such submissions, as well as an affirmation that no such arrangements exist would have to be provided by an officer of the relevant companies involved. This waiver of mitigation also applies to long-lead-time units.

Q IF ALL OF THE CONDUCT SCREENS ARE FAILED, WHAT IMPACT SCREEN DO YOU RECOMMEND?

A I recommend eliminating the impact screen. If the conduct screens I outline above are failed, the offers should be mitigated.

Q WHAT SUBSTITUTE SELL OFFER DO YOU RECOMMEND IN THE MITIGATION?

A If a new entrant is not determined to be economic at the initial screening and does not fall within one of the exemptions, it is then mitigated to an offer floor of 100 percent of the nominal levelized Unit Specific Net Cost of New Entry. This substitute Sell Offer applies for both long and short-lead-time units.

Q HOW WOULD THE SHORT-LEAD-TIME RESOURCE DEMONSTRATE ITS UNIT SPECIFIC COSTS?

A The process would be similar to the screening of a long-lead-time unit at the time of signing the Interconnection Service Agreement. A short-lead-time new entrant would provide the Independent Market Monitor or PJM with sufficient information to support such a calculation for nominal levelized unit gross Cost of New Entry (utilizing current PJM and Independent Market Monitor capital structure assumptions). The Independent Market Monitor or PJM would calculate location-specific energy and ancillary service offsets in a way similar to that currently used by the Independent Market Monitor to determine the net Avoidable Cost Rate for all offerers. Such mitigation would apply to all PJM auctions, the Base Residual Auction and all incremental auctions. The mitigation would continue for any portion of the unit until it cleared in two Base Residual Auctions.

Q WHY IS IT IMPORTANT TO USE THE GENERAL MARKET ASSUMPTIONS REGARDING THE COSTS OF CAPITAL FOR A MERCHANT GENERATION PLANT WHEN CALCULATING THE NOMINAL LEVELIZED UNIT SPECIFIC NET COST OF NEW ENTRY?

A For any party with a long-lead-time unit that may be receiving an out-of-market payment, the mitigated price needs to reflect the conditions and costs such a unit would face absent the out-of-market payment. The principal distortion that such payments create is in access to the cost of capital. Thus, mitigated unit specific costs must remove this bias. This is accomplished by using the capital structure any third party would face absent the out-of-market payments.

Q EXPLAIN WHAT IS MEANT BY NOMINAL LEVELIZATION AND WHY IT IS THE APPROPRIATE METHOD TO ESTABLISH A MITIGATED PRICE?

A Levelized prices can be established in two ways, nominal or real. Nominal levelized payments are calculated to create a constant annual stream of the same dollar amount each year that has a present value at a designated discount equal to a given amount. Real levelized payments reflect a stream of dollars increasing over time at the forecasted rate of inflation that has the present value when discounted equal to the same given amount. In this instance the “given amount” is the cost of constructing a new generating facility.

It is appropriate to base mitigation on the nominal stream because that is the cost stream that most closely matches the type of financial obligations associated with project financing. It basically is a cost structure similar to a mortgage. PJM and its Independent

Market Monitor have supported the use of the nominal levelized net Cost of New Entry in the calculation of the net Cost of New Entry values for the Reference Resource. In the current tariff, the first year of a real levelized stream of payments is used. To my knowledge this departure from the general calculation procedure was never justified.

Q WHY DO YOU PROPOSE THE "MITIGATED-TO" VALUE TO BE 100% OF THE UNIT SPECIFIC NET CONE FOR BOTH LONG AND SHORT-LEAD-TIME UNITS?

A While NYISO utilizes 75% of the reference Net Cost of New Entry and PJM currently would mitigate to 90% of that value, I concluded that these values are all too low. I discussed this at length above. The Reference Resource's Net Cost of New Entry is the value that the market is expected to average over time. If the new entrant were the Reference Resource, then mitigation to 100% of the Reference Resource essentially sets a cap on capacity compensation at the average value. It is hard to see how payments structured at average or less than average can be compensatory. Similarly as explained above, such a mitigation level is consistent with minimizing the cost of errors in trying to replicate competitive pricing levels. If anything, a higher value is needed to allow prices to hit the average and make up for the below average years and assure that market prices are not capped by mitigation at levels below that needed to support competitive entry.

Q ARE THERE OTHER REASONS FOR DEPARTING FROM THE NEW YORK CITY PRECEDENT AND USING THE 100% VALUE?

A Yes. A major distinction between NYC and just about anywhere else is the issue of open and competitive new entry. Most parties acknowledge that entry is very difficult in NYC, but there is no indication of such limitations in PJM or specifically in New Jersey. As noted, several thousand megawatts of supply have been originated in New Jersey to serve

New York, and several thousand MWs of generation and demand response have also been procured for New Jersey via RPM. If new entry were constrained, this might justify lower thresholds, but if competitive entry is already happening, it is difficult to reject the logic of the two main arguments I presented in the last answer regarding using 100% as the appropriate screen and mitigation levels.

In addition, under my recommendations, true competitive entry without a subsidy would not be mitigated. If an unsubsidized unit so desires, it can even offer as a price taker in the capacity auctions. This amplifies the point that not only is *competitive* entry allowed, but that my recommended mitigation raises no barrier to its entry. Thus the use of the 100% value for both the Reference Resource conduct screen and the unit specific "mitigate-to" value is both reasonable and justified.

Q HOW LONG SHOULD THE MITIGATION LAST?

A The mitigation would continue until the new entrant's mitigated offer clears two Base Residual Auctions. The mitigation would also be divisible for each portion of the unit that clears the auction. This period is consistent with the precedent in the Commission's recent NYISO In City Capacity mitigation Order.[45] There, with a monthly clearing process, the requirement was to clear in twelve auctions, which didn't necessarily need to be consecutive. Thus, because typically demand is higher, and capacity lower during the summer, the most likely clearing scenario is during two summer periods. Because PJM clears annually based on summer requirements, the use of two Base Residual Auctions is directly analogous.

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[45] *See N.Y. Indep. Sys. Operator*, 133 FERC ¶ 61,178 at P 49.

Q WHAT OTHER CHANGES DO YOU RECOMMEND?

A As outlined above, I would remove the conduct screen regarding net buyer status, and eliminate the ability of self-supply to circumvent any market mitigation. I would also eliminate the Minimum Offer Price Rule's limitation of mitigation to Planned Generation Capacity Resources as currently modified in the tariff and discussed above.

I also recommend a very strict anti-gaming provision that would provide that to the extent that the Independent Market Monitor determines that a mitigated new entrant cleared an auction due to any manipulation or scheme to circumvent the above provisions, mitigation will be re-imposed. Similarly, to the extent that any party finds a way to circumvent the above screens and mitigation, the Commission should actively enforce its market manipulation protections. Because of the forward nature of the markets, there is no reason why an auction should be settled without proper mitigation if there is concern regarding manipulation.

Q SHOULD THE COMMISSION ADOPT YOUR PROPOSED MITIGATION?

A Yes. My proposal is consistent with the Commission's approval of the NYISO in city capacity buyer-side mitigation and is otherwise economically efficient. Counsel has prepared matching tariff language to incorporate these recommendations into the provisions of Attachment DD of the PJM tariff.[46] I support the addition of this text into the PJM tariff to resolve the concerns addressed in this testimony.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

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[46] *See* Attachment A to the Complaint.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-___-000
	)	
PJM Interconnection, L.L.C.	)	
	)	

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the PJM Power Providers Group is true, correct, accurate and complete to the best of my knowledge, information, and belief.

Roy J Shanker
____
Roy Shanker

SUBSCRIBED AND SWORN to before me this _____ day of January 2011.

____
(Notary Public)

My commission expires: ______________

State of California County of
Monterey
Subscribed and sworn to (or affirmed)
before me on this 28 day of January, 2011, by
Roy Shanker,
proved to me on the basis of satisfactory evidence
to be the person(s) who appeared before me.
Signature Ramona L Nason
(Seal)

RAMONA L. NASON
Commission # 1816592
Notary Public - California
Monterey County
My Comm. Expires Oct 9, 2012

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 60450 Potomac MD 20854 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W.

Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2010

New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381

Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

Federal Energy Regulatory Commission. Docket ER11-2059Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cinergy Solutions regarding an energy services agreement related to a cogeneration facility.

Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacitycredits.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000,ER90-145-000 and El90-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided cost methodology recommended by the SCC Task Force.

Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

Florida Public Service Commission. Docket No. 8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factor application and relationship to avoided costs.

District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

Bonneville Power Administration. Case No. VI86.
Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas transportation rates.

Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

Scenario #	Input Parameters Tab	Scenario Description	Auction Results	RTO	MAAC	SWMAAC	PEPCO	EMAAC	DPL-SOUTH	PSEG	PS-NORTH
			Cleared MW	152,743.3	67,639.9	11,242.1	4,791.7	32,835.4	1,612.4	8,019.1	4,159.4
BASE	BASE	Actual 2013/2014 BRA Results	Resource Clearing Price	$ 27.73	$ 226.15	$ 226.15	$ 247.14	$ 245.00	$ 245.00	$ 245.00	$ 245.00
		Revise VRR Curve (*redefine curve using IRM-4%, IRM and IRM+4%*	Cleared MW	151,442.4	67,424.2	11,139.6	4,709.8	32,744.5	1,612.4	7,950.8	4,091.1
1	Simulation 1	*instead of IRM-3%, IRM+1% and IRM+5%*)	Resource Clearing Price	$ 24.34	$ 196.17	$ 196.17	$ 247.14	$ 206.34	$ 206.34	$ 206.34	$ 206.34
			Cleared MW	156,493.0	68,308.1	11,768.2	5,288.9	32,977.5	1,612.4	8,033.1	4,173.4
2	Simulation 2	Eliminate 2.5% Short-Term Resource Procurement Target (STRPT)	Resource Clearing Price	$ 42.00	$ 272.34	$ 272.34	$ 272.34	$ 324.01	$ 324.01	$ 324.01	$ 324.01
			Cleared MW	155,192.1	67,865.0	11,453.2	4,973.9	32,849.4	1,612.4	8,033.1	4,173.4
3	Simulation 3	Revise VRR Curve and Eliminate 2.5% STRPT	Resource Clearing Price	$ 37.51	$ 263.78	$ 263.78	$ 263.78	$ 303.30	$ 303.30	$ 303.30	$ 303.30
			Cleared MW	153,653.90	67,625.60	11,239.30	4,790.30	32,826.00	1,612.10	8,011.30	4,152.30
4	Simulation 4	Use 2012/2013 BRA IRM and FPR Values	Resource Clearing Price	$ 30.00	$ 226.06	$ 226.06	$ 247.14	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	67,338.50	11,053.90	4,660.60	32,744.50	1,612.40	7,950.80	4,091.10
5	Simulation 5	Use 2012/2013 BRA CONE Values	Resource Clearing Price	$ 27.73	$ 186.41	$ 186.41	$ 227.26	$ 210.46	$ 210.46	$ 210.46	$ 210.46
			Cleared MW	152,743.3	62,690.1	9,578.7	3,783.3	30,394.3	1,184.7	7,191.5	3,927.5
6	Simulation 6	Remove LDA Import Constraints	Resource Clearing Price	$ 60.32	$ 60.32	$ 60.32	$ 60.32	$ 60.32	$ 60.32	$ 60.32	$ 60.32
			Cleared MW	152,743.30	67,639.9	11,242.10	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
7	BASE	Remove 5000 MW from bottom of supply stack in rest of RTO	Resource Clearing Price	$ 62.00	$ 226.15	$ 226.15	$ 247.14	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	66,865.00	11,453.20	4,973.90	32,849.40	1,612.40	8,033.10	4,173.40
8	BASE	Remove 1000 MW from bottom of supply stack in rest of MAAC	Resource Clearing Price	$ 28.85	$ 261.23	$ 261.23	$ 261.23	$ 261.23	$ 261.23	$ 261.23	$ 261.23
			Cleared MW	152,743.30	66,981.00	11,441.10	4,973.90	31,977.50	1,612.40	8,033.10	4,173.40
9	BASE	Remove 1000 MW from bottom of supply stack in rest of EMAAC	Resource Clearing Price	$ 28.52	$ 256.05	$ 256.05	$ 256.05	$ 330.93	$ 330.93	$ 330.93	$ 330.93
			Cleared MW	152,743.30	67,270.70	11,258.90	4,791.70	32,449.40	1,612.40	7,633.10	3,773.40
10	BASE	Remove 400 MW from bottom of supply stack in PS-North LDA	Resource Clearing Price	$ 27.73	$ 243.07	$ 243.07	$ 247.14	$ 286.98	$ 286.98	$ 286.98	$ 286.98
			Cleared MW	152,743.30	67,591.80	11,194.00	4,726.80	32,835.40	1,612.40	8,019.10	4,159.40
11	BASE	Remove 400 MW from bottom of supply stack in PEPCO LDA	Resource Clearing Price	$ 27.73	$ 228.69	$ 228.69	$ 269.68	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	67,270.70	11,258.90	4,791.70	32,449.40	1,212.40	8,033.10	4,173.40
12	BASE	Remove 400 MW from bottom of supply stack in DPL-South LDA	Resource Clearing Price	$ 27.73	$ 243.06	$ 243.06	$ 247.14	$ 286.96	$ 286.96	$ 286.96	$ 286.96
			Cleared MW	152,743.30	67,639.9	11,242.10	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
13	BASE	Increase rest of RTO Supply by 5000 MW at $0	Resource Clearing Price	$ 16.06	$ 226.15	$ 226.15	$ 247.14	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	68,487.50	11,119.20	4,791.70	32,835.40	1,612.40	8,019.10	4,159.40
14	BASE	Increase rest of MAAC Supply by 1000 MW at $0	Resource Clearing Price	$ 25.64	$ 165.44	$ 172.36	$ 247.14	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	68,070.10	11,221.50	4,791.70	33,308.50	1,206.80	7,937.30	4,077.60
15	BASE	Increase rest of EMAAC Supply by 1000 MW at $0	Resource Clearing Price	$ 25.64	$ 195.33	$ 195.33	$ 247.14	$ 195.33	$ 195.33	$ 195.33	$ 195.33
			Cleared MW	152,743.30	67,931.90	11,225.00	4,791.70	33,144.50	1,612.40	8,350.80	4,491.10
16	BASE	Increase PS-NORTH LDA Supply by 400 MW at $0	Resource Clearing Price	$ 26.07	$ 205.23	$ 205.23	$ 247.14	$ 205.23	$ 205.23	$ 205.23	$ 205.23
			Cleared MW	152,743.30	67,891.80	11,493.90	5,060.60	32,835.50	1,612.40	8,019.20	4,159.50
17	BASE	Increase PEPCO LDA Supply by 400 MW at $0	Resource Clearing Price	$ 26.07	$ 208.11	$ 208.11	$ 208.11	$ 245.00	$ 245.00	$ 245.00	$ 245.00
			Cleared MW	152,743.30	67,931.90	11,225.00	4,791.70	33,144.50	2,012.40	7,950.80	4,091.10
18	BASE	Increase DPL-SOUTH LDA Supply by 400 MW at $0	Resource Clearing Price	$ 26.07	$ 205.23	$ 205.23	$ 247.14	$ 205.23	$ 205.23	$ 205.23	$ 205.23
			Cleared MW	152,743.3	67,565.8	11,258.9	4,791.7	32,744.5	1,612.4	7,950.8	4,091.1
19	Simulation 19	Full Susquehanna-Roseland Line	Resource Clearing Price	$ 27.73	$ 229.86	$ 229.86	$ 247.14	$ 229.86	$ 229.86	$ 229.86	$ 229.86
			Cleared MW	152,743.3	66,172.0	10,515.2	4,455.5	32,266.6	1,206.2	7,905.1	4,065.6
20	Simulation 20	Full Susquehanna-Roseland Line & PATH	Resource Clearing Price	$ 33.00	$ 135.59	$ 135.59	$ 135.59	$ 135.59	$ 135.59	$ 135.59	$ 135.59
			Cleared MW	152,743.3	65,638.8	10,217.0	4,339.3	32,087.2	1,206.2	7,845.1	4,046.0
21	Simulation 21	Full Susquehanna-Roseland Line & PATH & Partial MAPP	Resource Clearing Price	$ 37.51	$ 114.63	$ 114.63	$ 135.59	$ 114.87	$ 114.87	$ 114.87	$ 114.87
			Cleared MW	152,743.3	65,092.9	10,204.7	4,339.3	31,648.7	1,200.5	7,758.7	4,016.6
22	Simulation 22	Full Susquehanna-Roseland Line & PATH & Full MAPP	Resource Clearing Price	$ 38.10	$ 100.00	$ 100.00	$ 135.59	$ 100.00	$ 100.00	$ 100.00	$ 100.00

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments					5/17/2010	573450v8		

Updated: 5/17/2010 with Post-Clearing BRA Credit Rate

	RTO	Notes:
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.
Preliminary Forecast Peak Load	160,634.0	
Short-Term Resource Procurement Target	2.5%	
Pre-Clearing BRA Credit Rate, $/MW	$34,816	

		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,868.4**	99%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.

2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.

3/11/10 Update: Adjusted for FRR Alternative elections and obligations

4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	141,035.6	68,913.5	38,070.8	16,880.6	12,633.9	5,987.8	2,829.0	8,922.8
Point (b) UCAP Level, MW	146,239.0	71,451.0	39,472.3	17,501.5	13,098.8	6,208.0	2,933.0	9,250.4
Point (c) UCAP Level, MW	151,442.4	73,988.4	40,873.8	18,122.5	13,563.7	6,428.2	3,036.9	9,578.0
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
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PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

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2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	0.0%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
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Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	146,086.1	71,238.9	39,346.9	17,433.3	13,052.3	6,181.9	2,918.0	9,196.3
Point (b) UCAP Level, MW	151,289.6	73,776.4	40,748.4	18,054.2	13,517.2	6,402.0	3,022.0	9,523.9
Point (c) UCAP Level, MW	156,493.0	76,313.8	42,149.9	18,675.2	13,982.1	6,622.2	3,125.9	9,851.5
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**0.0**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	0.0	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	0.0	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	0.0	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	0.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	0.0	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	0.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	0.0	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	0.0	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	0.0	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	0.0	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	0.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	0.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	0.0	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	0.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	0.0	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	0.0	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	0.0	0.0	7,627.0
PS	5,950	**5,868.4**	99%	10,340.0	11,188.0	1.08201	0.0	0.0	11,188.0
PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	0.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	0.0	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	0.0	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	0.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	0.0	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	0.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	0.0	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.
2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	**Notes:**						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	0.0%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	144,785.3	70,604.5	38,996.5	17,278.0	12,936.1	6,126.8	2,892.1	9,114.4
Point (b) UCAP Level, MW	149,988.7	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Point (c) UCAP Level, MW	155,192.1	75,679.5	41,799.5	18,520.0	13,865.9	6,567.2	3,099.9	9,769.6
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**0.0**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	0.0	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	0.0	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	0.0	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	0.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	0.0	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	0.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	0.0	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	0.0	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	0.0	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	0.0	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	0.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	0.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	0.0	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	0.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	0.0	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	0.0	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	0.0	0.0	7,627.0
PS	5,950	**5,868.4**	99%	10,340.0	11,188.0	1.08201	0.0	0.0	11,188.0
PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	0.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	0.0	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	0.0	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	0.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	0.0	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	0.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	0.0	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.
2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments					5/17/2010	573450v8	

Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction

	RTO	Notes:
Installed Reserve Margin (IRM)	16.2%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.
Pool-Wide Average EFORd	6.44%	2. See "Net CONE" worksheet for Net CONE calculations.
Forecast Pool Requirement (FPR)	1.0872	3. Fixed Resource Requirement (FRR) elections were made on 3/3/10.
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.
Preliminary Forecast Peak Load	160,634.0	
Short-Term Resource Procurement Target	2.5%	
Pre-Clearing BRA Credit Rate, $/MW	$34,816	

		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	174,641.3	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,708.6**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**150,932.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,773.3	1,701.7	931.5	400.0	304.1	139.9	63.4	192.8
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	143,262.7	69,552.0	38,423.5	17,036.9	12,750.9	6,043.3	2,855.2	9,005.4
Point (b) UCAP Level, MW	148,458.3	72,069.8	39,814.1	17,653.1	13,212.2	6,261.7	2,958.3	9,330.4
Point (c) UCAP Level, MW	153,653.9	74,587.6	41,204.8	18,269.2	13,673.5	6,480.2	3,061.5	9,655.5
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.4%	69.8%	61.9%	67.5%	34.4%	64.3%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,773.3**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	82.1	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.9	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	240.8	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	363.2	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	207.1	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	656.1	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.7	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	79.4	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	574.5	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	110.3	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.4	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	183.0	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	83.3	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	240.0	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.6	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	192.8	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	207.3	0.0	7,627.0
PS	5,950	**5,868.4**	99%	10,340.0	11,188.0	1.08201	304.1	0.0	11,188.0
PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	139.9	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.1	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	931.5	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	400.0	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	370.2	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	1,701.7	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,497.1	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
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DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

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2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments					5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction							
	RTO	**Notes:**					
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.					
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.					
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.					
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.					
Preliminary Forecast Peak Load	160,634.0						
Short-Term Resource Procurement Target	2.5%						
Pre-Clearing BRA Credit Rate, $/MW	$34,816						

		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	7,095.0	6,724.9	5,868.4	2,570.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$276.09**	**$176.44**	**$212.50**	**$176.44**	**$212.50**	**$212.50**	**$212.50**	**$176.44**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$414.14	$264.66	$318.75	$264.66	$318.75	$318.75	$318.75	$264.66
Point (b) UCAP Price, $/MW-Day	$276.09	$176.44	$212.50	$176.44	$212.50	$212.50	$212.50	$176.44
Point (c) UCAP Price, $/MW-Day	$55.22	$35.29	$42.50	$35.29	$42.50	$42.50	$42.50	$35.29
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	89.9%	70.3%	62.3%	67.9%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.
*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**
DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,868.4**	99%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,570.0**	98%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**7,095.0**	101%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	6,724.9	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:
2/1/10: Original posting contained incorrect value for JCPL CETL.
2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0	99,999.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	-161.0%	-516.4%	-716.4%	-1684.3%	-3846.9%	-1181.5%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	99,999.0	7407%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**99,999.0**	> 115%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**99,999.0**	> 115%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**99,999.0**	> 115%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**99,999.0**	> 115%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	**99,999.0**	> 115%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**99,999.0**	> 115%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Pleasant View 500/230 kV transformer.
EMAAC	Elroy - Branchburg 500 kV line.
SWMAAC	Pleasant View 500/230 kV transformer.
PS, PSNORTH	Roseland - Cedar Grove "B" and "F" 230 kV lines.
DPLSOUTH	Voltage collapse after loss of Cedar Creek - Red Lion 230 kV line.
PEPCO	Pleasant View 500/230 kV transformer.

Prior Updates:

2/1/10: Original posting contained incorrect value for JCPL CETL.
2/5/10 Update: JCPL is removed as a constrained LDA as the corrected CETL exceeds 115% of CETO.
3/11/10 Update: Adjusted for FRR Alternative elections and obligations
4/13/2010 Update: Non-Zone Load (51 MW) associated with AEP Zone removed as it will not be served by PJM effective June 1, 2013.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	**Notes:**						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	4,460.0	8,707.0	6,724.9	5,973.0	2,742.0	2,123.0	4,483.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	70.3%	61.5%	64.8%	34.6%	64.7%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**4,483.0**	111%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,973.0**	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,742.0**	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**8,707.0**	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	**6,724.9**	117%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**4,460.0**	106%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	Notes:						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	7,192.0	8,707.0	7,728.0	5,973.0	2,742.0	2,123.0	5,077.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	64.0%	61.5%	64.8%	34.6%	57.0%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**5,077.0**	126%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,973.0**	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,742.0**	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**8,707.0**	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	**7,728.0**	135%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**7,192.0**	172%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction								
	RTO	**Notes:**						
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.						
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.						
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.						
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.						
Preliminary Forecast Peak Load	160,634.0							
Short-Term Resource Procurement Target	2.5%							
Pre-Clearing BRA Credit Rate, $/MW	$34,816							
		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	8,018.0	8,707.0	8,126.0	5,973.0	2,742.0	2,123.0	5,158.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	85.6%	61.5%	61.5%	64.8%	34.6%	55.9%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
APS	700	> 805	> 115%	8,150.0	8,859.0	1.08699	239.3	0.0	8,859.0
ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	2,123.0	157%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**5,158.0**	128%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,973.0**	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,742.0**	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**8,707.0**	124%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	**8,126.0**	142%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**8,018.0**	191%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

2013-2014 RPM Base Residual Auction Planning Parameters with FRR Adjustments					5/17/2010	573450v8	
Yellow Cell indicates that input parameter differs from that used in actual 2013/2014 Base Residual Auction							

	RTO	Notes:
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2010 Load Report, adjusted for Non-Zone Load.
Pool-Wide Average EFORd	6.30%	2. See "Net CONE" worksheet for Net CONE calculations.
Forecast Pool Requirement (FPR)	1.0804	3. Fixed Resource Requrement (FRR) elections were made on 3/3/10.
Demand Resource (DR) Factor	0.957	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.
Preliminary Forecast Peak Load	160,634.0	
Short-Term Resource Procurement Target	2.5%	
Pre-Clearing BRA Credit Rate, $/MW	$34,816	

		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**
CETO	NA	4,190.0	7,050.0	5,740.0	5,950.0	2,620.0	1,350.0	4,030.0
CETL	NA	8,768.0	9,555.0	8,126.0	5,973.0	2,742.0	2,406.0	5,158.0
Reliability Requirement	173,549.0	73,142.0	40,398.0	17,899.0	13,401.0	6,347.0	2,996.0	9,442.0
Total Peak Load of FRR Entities	21,807.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Preliminary FRR Obligation	**23,560.3**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**149,988.7**	**73,142.0**	**40,398.0**	**17,899.0**	**13,401.0**	**6,347.0**	**2,996.0**	**9,442.0**
Short-Term Resource Procurement Target	3,749.7	1,691.0	925.7	397.5	302.2	139.0	63.0	191.6
Net CONE, $/MW-Day (UCAP Price)	**$317.95**	**$227.20**	**$261.06**	**$227.20**	**$261.06**	**$261.06**	**$261.06**	**$227.20**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$476.93	$340.80	$391.59	$340.80	$391.59	$391.59	$391.59	$340.80
Point (b) UCAP Price, $/MW-Day	$317.95	$227.20	$261.06	$227.20	$261.06	$261.06	$261.06	$227.20
Point (c) UCAP Price, $/MW-Day	$63.59	$45.44	$52.21	$45.44	$52.21	$52.21	$52.21	$45.44
Point (a) UCAP Level, MW	142,336.4	69,547.9	38,421.2	17,035.8	12,750.1	6,042.9	2,855.0	9,004.7
Point (b) UCAP Level, MW	147,539.9	72,085.3	39,822.7	17,656.8	13,215.0	6,263.0	2,958.9	9,332.3
Point (c) UCAP Level, MW	152,743.3	74,622.8	41,224.2	18,277.7	13,679.9	6,483.2	3,062.9	9,659.8
Min % Int. Resources Req'd for FRR Load	NA	100.0%	83.3%	61.5%	61.5%	64.8%	23.4%	55.9%
Participant-Funded ICTRs Awarded	NA	**159.0**	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate, $/MW	$ 7,300.00	$ 16,509.00	$ 17,885.00	$ 16,509.00	$ 17,885.00	$ 17,885.00	$ 17,885.00	$ 18,041.00

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL South and PS North values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2009 W/N Zonal Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	Short-Term Resource Procurement Target	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load
RTO	NA	NA	NA	**145,930.0**	**160,634.0**	NA	**3,749.7**	0.0	**138,827.0**
AE	1,710	> 1967	> 115%	2,550.0	3,019.0	1.18392	81.5	0.0	3,019.0
AEP	*	*	NA	22,540.0	24,084.0	1.06850	61.5	21,807.0	2,277.0
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ATSI	3,870	> 4451	> 115%	12,150.0	13,364.0	1.09992	361.0	0.0	13,364.0
BGE	3,970	> 4566	> 115%	7,000.0	7,621.0	1.08871	205.8	0.0	7,621.0
COMED	2,880	> 3312	> 115%	21,300.0	24,138.0	1.13324	652.0	0.0	24,138.0
DAYTON	720	> 828	> 115%	3,150.0	3,521.0	1.11778	95.1	0.0	3,521.0
DLCO	910	> 1047	> 115%	2,760.0	2,922.0	1.05870	78.9	0.0	2,922.0
DOM	1,300	> 1495	> 115%	18,290.0	21,138.0	1.15571	570.9	0.0	21,138.0
DPL	1,000	> 1150	> 115%	3,800.0	4,059.0	1.06816	109.6	0.0	4,059.0
DPLSOUTH	1,350	**2,406.0**	178%	NA	2,333.9	NA	63.0	0.0	2,333.9
JCPL	4,140	> 4761	> 115%	6,060.0	6,733.0	1.11106	181.9	0.0	6,733.0
METED	550	> 633	> 115%	2,770.0	3,064.0	1.10614	82.8	0.0	3,064.0
PECO	2,720	> 3128	> 115%	8,260.0	8,830.0	1.06901	238.5	0.0	8,830.0
PENLC	340	> 391	> 115%	2,680.0	2,929.0	1.09291	79.1	0.0	2,929.0
PEPCO	4,030	**5,158.0**	128%	6,690.0	7,094.0	1.06039	191.6	0.0	7,094.0
PL (incl. UGI)	670	> 771	> 115%	7,030.0	7,627.0	1.08492	206.0	0.0	7,627.0
PS	5,950	**5,973.0**	100%	10,340.0	11,188.0	1.08201	302.2	0.0	11,188.0
PSNORTH	2,620	**2,742.0**	105%	NA	5,146.5	NA	139.0	0.0	5,146.5
RECO	NA	NA	NA	410.0	444.0	1.08293	12.0	0.0	444.0
EMAAC	7,050	**9,555.0**	136%	NA	34,273.0	NA	925.7	0.0	Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,740	**8,126.0**	142%	NA	14,715.0	NA	397.5	0.0	
Western MAAC	*	*	NA	NA	13,620.0	NA	367.9	0.0	
MAAC	4,190	**8,768.0**	209%	NA	62,608.0	NA	1,691.0	0.0	
Western PJM	*	*	NA	NA	76,888.0	NA	1,487.7	21,807.0	

NOTE: Sensitivity scenarios 19 through 22 required calculation of CETL values for each LDA that was modeled in the 2013/2014 BRA given various backbone transmission line assumptions. To provide a comparison with the original 2013/2014 BRA CETL results, power flow cases similar to those used for the original 2013/2014 BRA CETL analysis were modified based on the given scenario and CETL values were calculated. Other assumptions regarding load, generation and transmission topology that are currently being used in the 2010 RTEP were not included in this analyses.

BEFORE THE
NEW JERSEY SENATE ENVIRONMENT AND ENERGY COMMITTEE

November 15, 2010
December 9, 2010

S-2381 (Smith, Bateman)
Assembly 3442

STATEMENT OF ROY J. SHANKER PH.D.
ON BEHALF OF COMPETITIVE SUPPLIERS COALITION

1) My name is Roy J. Shanker. I am an independent consultant working principally in the electricity markets. I have been asked here today by Constellation NewEnergy, Inc. and Constellation Commodities Group, Inc., Exelon Corporation, Mirant Corporation, PPL Energy, RRI Energy, and Suez Energy (Competitive Suppliers Coalition) to comment on the proposed actions being considered by the New Jersey legislature in Senate Bill 2381/Assembly Bill 3442 (S-2318 or the Bill).

2) I have significant experience with both the PJM markets and with energy policy matters and associated regulation in New Jersey. I participated as part of the team that drafted the very first New Jersey State Energy Plan over thirty years ago, and have worked for a number of electric suppliers, utilities, and industrial customers in the state. I have over 37 years of experience, and have been an independent consultant for 30 years. During much of that period I worked with the same range of clients in

other matters related to PJM. In particular I have been very active in the PJM competitive electricity markets and the associated stakeholder processes since the very inception of the new ISO/RTO construct in the mid 1990's. I have attached a summary of my qualifications and relevant experience.

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS.

3) I have reviewed S-2381 and the revised version and amendments provided with ASM-3442 and have concluded that the proposal to enact new customer surcharges on all New Jersey customers in order to guarantee revenues and thereby induce construction of new in-state electric generation will increase New Jersey electricity costs in the long run, and impose risks on customers that should be borne by energy company shareholders. In reaching this conclusion, I have identified several major flaws with Bill.

4) First, there appears to be no need to use revenue guarantees to induce new generating capacity in New Jersey. The preponderance of indications are that current supplies, coupled with future transmission enhancements, are more than sufficient to serve New Jersey electricity customers reliably and the Bill does not reasonably identify anything to the contrary. Further, there is no indication that the underlying PJM capacity

market and transmission planning process is deficient in terms of meeting reliability goals.[1]

5) Second, based on my review, the apparent reason for the proposal is the perceived “savings” in energy and capacity markets associated with the anti-competitive behavior of purchasing excess uneconomic supplies to suppress overall market prices.

6) In combination, these flaws fatally undermine any legitimate rationale for this Bill that would commit millions of consumer dollars to subsidizing select new electric generating capacity in New Jersey. Understanding the widespread harmful impact of this uneconomic initiative should clarify the public interest at issue.

7) This legislation would give discriminatory and preferential treatment to certain new generation capacity suppliers or undefined implementation of environmental upgrades, which would have the effect of shifting the risks of unnecessary new generation capacity and investment to New Jersey ratepayers from those generation developers. That subsidized generation then would be used to depress prices in the competitive market. This applies equally to new generation or out of market inducements related to environmental investment. Thus this Bill would have the effect in the market

[1] I do take issue with other elements of the PJM Reliability Pricing Model forward capacity market design.

of artificially depressing market prices using anti-competitive buyer market power. In the long run it would harm competitive capacity markets and cost customers more for generation capacity than otherwise.

8) Further, the use of rate-funded subsidies to support discriminatory investment would result in higher, not lower, overall costs to supply electricity. Although short-term wholesale market prices may be lower than they would have been without the subsidized new generation capacity, total societal costs are higher, because of both excess new capacity and uneconomic retirement of existing capacity. The subsidized entry is "unnecessary" and consumes resources that could be better used elsewhere in the economy. At the same time, the wholesale market price suppression will prompt uneconomic retirement, as some resources may be unable to continue to operate at artificially depressed prices. The uneconomic retirement can also increase the total costs of electricity as more costly new capacity replaces the capacity that was prematurely retired. Similarly, total employment may decrease, as the jobs lost at the older, otherwise economic generators that retire could exceed new jobs created.

9) New Jersey does not need new generation capacity. The argument for "energy independence" for New Jersey turns its back on more than half

a century of increasingly efficient coordination among Pennsylvania, Maryland and New Jersey utilities to share in the benefits of economic dispatch of baseload generation and the resulting integrated regional electric network. Further, to my knowledge there has been no demonstration of any real adverse reliability problems in New Jersey. In fact, as discussed below, the current and near future situations seem more indicative of a surplus market. Moreover, New Jersey has over 17,000 MWs of generation capacity in operation and significant demand response, none of which are subsidized by customers. Over the last decade alone, companies in New Jersey have built over 4,500 MWs of new generation, added nearly a 1000 MW of demand response, and upgraded dozens of existing plants, without relying on such subsidies.

II. BACKGROUND: EXPLANATION OF THE TERMS OF S-2381 AND ASSEMBLY 3442 (AS AMENDED)

10) If enacted as proposed, the Bill would establish a long-term capacity agreement pilot program to enable the construction or environmental improvements of at up to 1000 MW of generation facilities in certain locations within the state of New Jersey. The Bill would do so by creating a program in which eligible new generators will be awarded contracts to sell capacity to New Jersey utilities, with the price set at the higher of the PJM

Reliability Pricing Model (RPM) auction clearing price or a legislatively-set floor. Eligible generators would be required to bid and clear in the RPM auction in order to participate in the pilot. Effectively this would force them to bid as a price taker or at a zero offer price. But these select generators would be guaranteed a price of for their capacity that clears in the RPM auction based on the legislative price regardless of the actual auction results. (Originally this was proposed as $232.75 per MW/day) If the RPM clearing price is below that guaranteed price, the generator would be paid the difference between the RPM clearing price and guaranteed price by the utility, with that guaranteed payment funded through a non-bypassable charge to all state utility customers. If the clearing price is above the guaranteed price, the generator will be paid the higher clearing price, or as now proposed refund this amount retaining the “locked in” floor. The stated purpose of the Bill is to avoid reliance on out-of-state at-risk power plants and to ensure that in-state generation will help the state reduce the cost and volatility of electricity prices. It is also intended to assist the state’s economic development through employment opportunities.

III. THE CURRENT RELIABILITY PROCEDURES ARE WORKING AND THERE IS NO RELIABILITY FAILURE.

11) The legislature has a reasonable concern that New Jersey residents continue to be provided with reliable electric service. But there is no indication that the current energy and capacity markets and transmission system operated by PJM are unreliable. To my knowledge, there has been no formal planning exercise, subject to the open participation of expert parties such as the BPU, FERC, PJM and others, as contemplated in PJM's tariff, which has reached any conclusion that generation is inadequate in New Jersey. Further, there is simply no factual basis developed anywhere for any concern there may be a reliability need justifying more "in state" supplies for New Jersey. In fact, as discussed below, it appears that many New Jersey "expert" bodies reached exactly the opposite conclusion.

12) PJM offered comments In The Matter of the New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs, Docket No. EO09110920, Technical Conference (June 24, 2010), related to overall reliability concerns as reflected by supply/demand balances and the associated pricing and functionality of RPM, which is used as the "engine" of the PJM capacity market. I have reviewed those comments, and while

PJM acknowledged the potential for decline in supply due to impending emission controls under EPA regulations that would result in some coal plant retirements, PJM also concluded that the general balance in supply and demand has been maintained over time, and that the RPM process complements continued reliability. Further, while some “vulnerability” was noted in northern New Jersey, this appears to be fully addressed by the timely addition of the Susquehanna-Roseland transmission facility. Thus, RPM is doing what it is intended to do, providing locational price signals tied to local capacity needs to complement the overall PJM planning processes, which assure reliability.

13) Potential changes in supply and demand are addressed in PJM’s multi-tiered reliability planning processes, which are designed to ensure adequate regional supplies. While the detail is extensive, one of the basic building blocks for reliability, in both the capacity market and in transmission planning, entails maintaining adequate supplies in the Local Deliverability Areas (LDAs) such as Eastern MAAC, PSEG and North PSEG.[2] In fact, any deficiency in these requirements (e.g. a projected

[2] While reliability requirements for PJM as a whole (and nationally) are based on one outage in ten years, within PJM the standard is one event in 25 years between each LDA and the remainder of PJM. This one event in 25 years criterion is used to assure reliability based on having sufficient transmission deliverability between internal LDA resources and supplies on a pool wide basis at levels that are consistent with the overall one event in ten years objective.

shortage of local resources or transmission limits into an LDA) mandates new transmission facilities for reliability, and also results in financial incentives for generation to be retained in any potentially deficient area. The mandate is just that – it is incorporated in the formal reliability rules that PJM has adopted and *must* follow. Further, PJM also has incorporated backstop rules into its generation procurement should "normal" purchases not be enough due to unanticipated events. Thus while there may be "swings" in supply they are anticipated and the entire process is designed to ensure that no reliability shortage can persist.

14) To my knowledge no one has demonstrated that this process isn't working. Further, the New Jersey Board of Public Utilities, the Public Power Association of New Jersey and the New Jersey Department of the Public Advocate, Division of Rate Counsel joined in a formal complaint proceeding at FERC alleging that this process is too conservative and results in an unnecessarily high level of reliability and associated capacity. These three New Jersey parties were part of a group that challenged this entire reliability planning concept, seeking ***lower*** levels of reliability and planning standards than current PJM practices. They were advocating approximately a 3.5% reduction in installed capacity in the eastern regions

of PJM.[3] Thus these parties, presumably the most knowledgeable parties in New Jersey with respect to electric utility matters, argued that there is too much, not too little, reliability under the status quo.

15) Empirically the results of the RPM auctions also seem to confirm this. As noted above, Mr. Wilson testified on behalf of New Jersey ratepayer interests that the cleared capacity for EMAAC was far in excess of what was appropriate during the initial RPM auctions. For PJM as a whole, quantities of capacity in excess of target requirements have cleared in all of the RPM auctions. For the EMAAC and New Jersey LDA's, this also has typically been the case. A summary of these results, initially compiled by

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[3] *See Maryland Public Service Comm'n, et al. v. PJM Interconnection, LLC,* Docket No. EL08-67, Complaint of the RPM Buyers (filed May 30, 2008) (Affidavit of James Wilson at 58-59, footnotes omitted, emphasis added). The RPM Buyers included the New Jersey Board of Public Utilties, the New Jersey Public Power Association and New Jersey Rate Counsel, sponsoring the following testimony of James Wilson:

> PJM Used An Unreasonable Reliability Standard For LDAs.
>
> In determining CETO and Reliability Requirements for LDAs, PJM applied a much more stringent planning resource adequacy standard than the traditional one-occurrence-in-ten years, thereby further increasing the Reliability Requirement in LDAs and, again, shifting the VRR curve to the right. PJM has reasoned that in order for the entire PJM region to be planned based on a single reserve margin reflecting the one-occurrence-in-ten years resource adequacy criterion, the PJM transmission system must be planned so that LDAs meet a much more rigorous criterion. While this standard may be reasonable for transmission planning, the manner in which PJM carried it over and applied it to establishing LDA Reliability Requirements during the transition period is not reasonable.
>
> In setting the CETO and the Reliability Requirement for each LDA, PJM has chosen to apply a one-occurrence-in-25 years standard, *i.e.*, the LDA is expected to shed load due to insufficient internal generation plus import capability only once in 25 years. Earlier studies of the relationship between reserve margin and outage frequency suggest that this more stringent criterion applied to the calculation of LDA Reliability Requirements increases the capacity that must be provided by at least three percentage points, further shifting the VRR curve to the right and increasing the clearing price. By applying this overly conservative planning standard, PJM set Reliability Requirements for SWMAAC that correspond to installed reserve margins of more than 20 percent, *and the actual cleared capacity in EMAAC and SWMAAC corresponded to installed reserve margins of 19 percent or more in all four transitional BRAs – far above the 15.5 percent reserve that PJM deems adequate for system reliability and that it applies to the RTO Region as a whole.*

the PJM Market Monitor, appears below in Table A. The highlighted row shows the excess of the actual procured amount over the target values. New studies emphasize this as a continuing trend as new transmission facilities are added to the system. In fact, technical evaluations conducted by the Competitive Supplier Coalition by Charles River Associates indicate that after planned transmission improvements, prices will decline significantly in New Jersey, to a level approximately $100 per MW/day lower than the original Senate proposal. This would result in locking in New Jersey customers for what was proposed to be 15 years of “out of the money capacity”.

BRA AUCTION RESULTS	PY '07/08	PY '08/09	PY '09/10	PY '10/11	PY '11/12	PY '12/13			PY '13/14	
	EMAAC	EMAAC	MAAC+APS	RTO	RTO	MAAC	EMAAC	PS-North	MAAC	EMAAC
Reliability Requirement	37,236.7	37,890.7	77,902.9	132,698.8	130,658.7	72,125.0	40,145.0	6,324.0	73,142.0	40,398.0
Total Cleared	30,797.8	30,231.3	72,547.7	132,190.4	132,221.5	65,452.4	31,080.2	3,521.9	67,653.9	32,849.4
CETL	5,845.0	7,930.0	4,941.0	N/A	N/A	6,377.0	9,079.0	2,755.0	4,460.0	7,095.0
Total Resources	36,642.8	38,161.3	77,488.7	N/A	N/A	71,829.4	40,159.2	6,276.9	72,113.9	39,944.4
Short Term Hold Back	N/A	N/A	N/A	N/A	N/A	1,673.9	922.8	136.8	1,691.0	925.7
Net Excess/(Deficit)	(593.9)	270.6	(414.2)	1,149.2	3,156.6	1,378.3	937.0	89.7	662.9	472.1
ILR Forecast	385.5	396.1	1,055.7	2,110.5	1,593.8	N/A	N/A	N/A	N/A	N/A
DR Offered	44.7	343.4	820.6	967.9	1,652.4	5,029.2	1,787.3	67.6	5,871.1	2,461.3
DR Cleared	44.7	168.7	813.9	939.0	1,364.9	4,723.7	1,638.4	67.6	5,871.1	2,461.3
Resource Clearing Price	$197.67	$148.80	$191.32	$174.29	$110.00	$133.37	$139.73	$185.00	$226.15	$245.00

TABLE A

16) Adopting S-2381/A-3224 would work against the existing reliability construct. Indeed, the reason developers pursue the type of revenue guarantee offered by the Bill is because market prices are signaling that new capacity is not needed. But guaranteeing a price for unneeded capacity simply makes matters worse. As discussed below, subsidizing uneconomic new capacity adds to the existing capacity surplus, suppresses prices for all other suppliers, deters competitive new entry, and likely forces some existing capacity to retire prematurely. It is a form of price discrimination, pure and simple. Essentially the Bill would result in a world where new entry can occur only via this type of discriminatory contract thereby undermining existing mechanisms in which utility and generation shareholders bear the bulk of the risk. The simple observation here is that the current system appears to be working, at least with respect to reliability (though prices may actually be too low),[4] and it is a mistake to introduce a discriminatory mechanism that will distort prices and undermine the legitimate stated objective – reliability.

[4] While reliability thus far has been maintained, there are legitimate arguments that several aspects of the current RPM design depress prices below truly competitive levels.

IV. THE UNDERLYING REASON FOR THE LEGISLATIVE PROPOSAL APPEARS TO BE THE ANTI-COMPETITIVE SUPPRESSION OF CAPACITY AND ENERGY PRICES.

A. AN "IN MARKET" COMPETITIVE BI-LATERAL AGREEMENT VERSUS BUYER MARKET POWER.

17) It certainly isn't unreasonable for New Jersey to consider entering into bi-lateral agreements for the purchase of energy and capacity on behalf of the state's electricity consumers. However, I would expect that such agreements would be competitive, economic, fuel-neutral, arms' length, and non-discriminatory bi-lateral contracts that would not differentiate between new and existing resources. Though the answer may be complicated, the question to determine whether such criteria are met is simple: on a *stand-alone* basis, do the economics of the transaction convey sufficient benefit to the buyer to justify the cost. If the answer is yes, then it is reasonable to proceed.[5]

18) Buyer market power is the ability of buyers to make discriminatory investments in uneconomic capacity resources that then flood the market with excess capacity, thereby artificially suppressing market prices for all capacity resources and allowing the buyers to recover their above-market expenditures by means of the portfolio savings. That is, the resource

[5] This question is analogous to one of the FERC's considerations regarding whether a market action is appropriate versus potential market manipulation: does the transaction reflect a legitimate business purpose?

purchased is itself uneconomic, but the purchase results in "savings" based on artificially lowering all other prices. The ability to recover the uneconomic costs of the new resource through cost-of-service rate making or its equivalent makes such an anti-competitive strategy even more effective and destructive. Consumers are essentially guaranteeing that those exercising market power are both successful and profitable.

B. THE BILL WOULD RESULT IN UNECONOMIC ENTRY AND EXERCISE OF BUYER MARKET POWER.

19) In all the material I have reviewed, I have seen no analyses that support the view that the generation procurement proposed by the Bill makes economic sense. All information I have seen relates to the "portfolio effect" of the acquisition on total energy and capacity prices, not the stand-alone economics of any proposed transaction. To me this indicates that the real underlying rationale of the proposed procurement is not reliability, and that it does not further a legitimate business purpose. Rather, the proposed legislation is designed to exercise buyer market power to purchase uneconomic supplies in order to artificially suppress prices.

20) The Bill is proposing to discriminate among generation resources by guaranteeing a price to some, but not all, suppliers in order to attract only new uneconomic resources. These suppliers would be able to bid into the

capacity auction at a price below their long-term average cost because that cost would be paid by the non-bypassable surcharge subsidy. The purchasers of the uneconomic resource, i.e. the utilities, are protected from the direct out of market cost by the non-bypassable surcharge to consumers, and all purchasers benefit from the price suppressing impact of the excess. The only economic analyses that have been presented in this and related BPU proceedings address ***only*** these portfolio benefits of the exercise of market power. Nowhere is there any indication of the stand-alone value of the proposed bi-lateral agreements supported by the Bill. Presentations by LS Power indicate that energy prices as a whole may be depressed by $98 million per year.[6] Similarly, the New Jersey Rate Counsel submitted recent comments to the BPU estimating that capacity prices would be suppressed on the order of $465 million by adding 500 MW of otherwise unneeded capacity.[7] These are not true savings, however, they are just wealth transfers from unsubsidized, competitive sellers to buyers, realized via the exercise of the buyers' market power.

21) As I recently commented at FERC, market sellers could engage in analogous behavior by cooperating to uneconomically withhold supply from

[6] LS Power Presentation, page 11. Note that this is likely a high side estimate as it is based on the absence of the significant new transmission being planned for the region. (Susquehanna Roseland)
[7] BPU Docket No. EO09110920, Submission of New Jersey Rate Counsel, at 8 (July 2, 2010).

the market, such as by paying otherwise economic resources to retire from the market to realize increased prices for their remaining portfolio and that of remaining market participants. For example, using the Rate Counsel's estimate, if suppliers withheld 500 MW of capacity, the remaining participants would increase their revenues by approximately $465 million dollars per year. This results in sufficient funds to "bribe" the 500 MW to retire, with the remaining market suppliers sharing excess. This isn't good economics, it is the symmetric application of inappropriate market power.

22) Finally, as I stated above, new studies sponsored by the Competitive Supplier Association now finally do provide at least a glimpse of a stand-alone evaluation, and show that after transmission improvements are in place the rate proposed in the Senate version of the Bill, New Jersey would initially be overpaying by approximately $100 per MW day versus market priced capacity.

C. THE EXERCISE OF SUCH BUYER MARKET POWER ULTIMATELY HARMS THE PUBLIC INTEREST.

23) A market cannot remain viable if it is subject to the exercise of market power, intentional or not, by either buyers or sellers. The Bill represents a classic example of monopsony or "buyer market power" that would artificially suppress market prices for the benefit of select suppliers who

have guaranteed subsidies outside the market. Under the declining demand curve design of the PJM capacity market, forcing excess supply into the market reduces all prices paid, and the cost of the inefficient excess can be offset by “savings” from reducing payments to others. While more entry and price suppression may seem like good things for customers, the reality is that uneconomic entry subsidized by ratepayers increases total electricity costs in the long run and is not compatible with efficient wholesale markets. Such market manipulation is harmful because it can (a) stimulate uneconomic demand for power and consequent inefficient consumption of resources; (b) increase total societal costs due to both excess new supply and premature retirement of resources that would be economic in a competitive market; and (c) discourage new competitive entry, including demand response, and add risk premiums to supplier costs. In other words, as I explain in more detail below, it can undermine the long-run viability of the entire competitive market model and ultimately result in higher total costs.

24) Consumers are harmed because lack of competition and distorted short term gains from market manipulation spawn inefficiencies in the supply of electricity. Some of this is even visible in the proposed legislation itself. For example, typically I would expect that since New Jersey rate

payers are bearing all of the capital risk of the new projects, they would also see the benefit of the energy margins earned when prices exceed the production cost of the underlying new facility. That is not the case here, since all energy margins accrue to the seller. Similarly in most such contracts the presence of a guaranteed capacity payment “fixes” the price, with any upside going to the buyer. Again that is not the case here. The proposed $232 MW/day price is a floor, with all upside from the market going to seller. Because there is no competition in these arrangements, and the reliance on the anti-competitive price suppression effect is superficially attractive, such typical contract protections for the buyers are overlooked. This is exactly why we tried to avoid totally administrative solutions and introduce market mechanisms into procurement in the electric energy sector. In addition, the non-bypassable charge to consumers would especially penalize those customers who acted prudently on their own to hedge their exposure to market prices, as they already will have expended funds for the hedge positions, but then would be forced to pay a second time via the surcharge.

25) Suppliers are victimized by the price discrimination which effectively creates an unjustified two-tier market where all market participants provide the same reliability product or service, but certain individual new entrants

are paid a higher price and all other existing suppliers unjustifiably are paid a lower price. Ultimately no one will seek to enter the market other than by such subsidies, as a supplier without such protection would be victimized through the exercise of buyer market power. To compensate for that risk, any entrant would have to be compensated by ever increasing price levels, encouraging ever greater use of buyer market power. The increased risk shows up in all of the future bilateral contract costs and total costs to consumers are increased.

26) Both consumers and suppliers would be harmed by the effect of the market distortion on existing generation capacity. Because market prices would be artificially depressed, some resources that would have cleared in a competitive auction will fail to clear the market, and therefore will retire. This effect will inefficiently accelerate the “turn-over” of the entire capital generation stock and the associated premature loss of jobs, while increasing unnecessary investments.

27) These types of adverse effects are not news to either economists or regulators. The Federal Energy Regulatory Commission has explicitly rejected this type of discriminatory pricing in the ISO-NE, PJM and NYISO capacity markets. In accepting the NYISO demand curve design for capacity payments, the Commission explicitly rejected the argument that it

would be appropriate to price in such a manner so as to discriminate between new entrants and existing capacity, stating: "The Commission finds that all capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. . . . The Commission does not see how [new] generators could receive ICAP revenues that were fundamentally different from those paid to other generators."[8] Any attempt to bypass such decisions via the exercise of market power would impair the function of the capacity market over time and as a result also lead to the need for existing suppliers to rely on cost-based Reliability Must Run contracts for the remaining capacity that otherwise would have been "in market" but for the price discrimination. This bill fosters the very harm the FERC has spent the last three years attempting to rectify in all three of the eastern RTO capacity markets.[9]

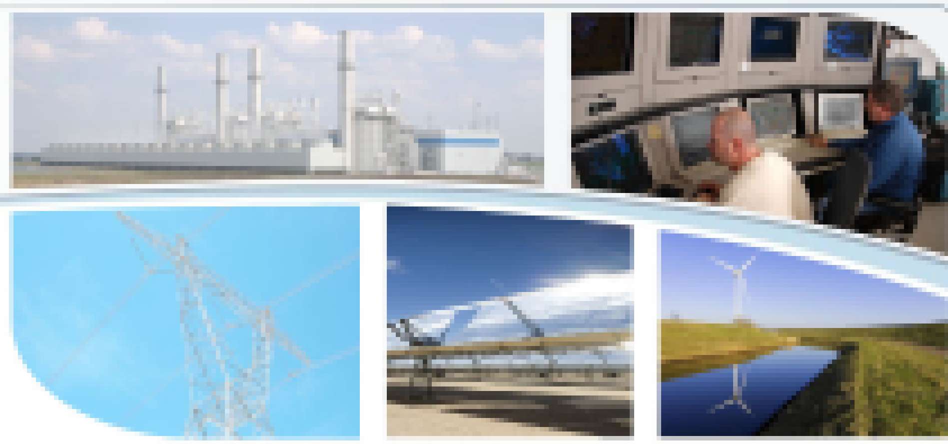
28) Thus I would expect that the Bill will exacerbate the very problem it purports to address. It will have a further chilling effect on future economic

[8] *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 81 (2003). Similarly, the Commission endorsed uniform market clearing prices for all participants, new entrant or existing. *See id.* at PP 77, 81.

[9] *See*, *e.g.*, *ISO New England Inc.*, 120 FERC ¶ 61,087 at P 2 (2007) (recounting history of FCM in New England, and highlighting "concerns regarding the number of generators seeking" RMR contracts "and the effect that widespread use of such contracts could have on the competitive market"); *Devon Power LLC.*, 103 FERC ¶ 61,082 at P 29 (2003) ("extensive use of RMR contracts undermines effective market performance"); *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, *order on reh'g*, 128 FERC ¶ 61,157 (2009); *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006), *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power LLC.*, 113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340 at P 7 (2006); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh'g denied*, 122 FERC ¶ 61,064 (2008); *New York Indep. Sys. Operator, Inc.*, 111 FERC ¶ 61,117, *reh'g denied*, 112 FERC ¶ 61,283 (2005); *New York Indep. Sys. Operator, Inc.*, 89 FERC ¶ 61,109 (1999).

capacity development, and may ultimately challenge the sustainability of the competitive market model. If utility funding of new entry creeps into the market construct, developers will not commit substantial capital to new merchant generation, because they will not take the risk that their investment could be "devalued" by regulatory guarantees.

LS Power



New In-State Generation
LS Power Energy Savings Analysis

November 2010

Bringing Energy Forward

Energy Savings
Impact of New, In-State Generation

- Developing new, efficient, combined cycle generation in NJ will reduce energy and capacity costs to NJ ratepayers
- Energy savings
  - LS Power estimates that energy savings would be approximately $125 million/year
  - These savings are in addition to Rate Counsel's estimate of capacity savings
- Following is a discussion of the LS Power energy savings analysis

- Note on Capacity Market savings
  - NJ Rate Counsel provided comments in the June 24, 2010 BPU Technical Conference suggesting new, in-state generation could save NJ ratepayers approximately $465 million/year in capacity payments. The analysis herein only considers the savings realized in the energy market

Analysis Model Description/Overview – Model Provider Overview

- Energy analysis model provided by Cambridge Energy Solutions (“CES”)
- CES is a software company with a mission to develop software tools for participants in deregulated electric power markets.
- CES provides information and tools to assist market participants in analyzing the electricity markets on a locational basis, forecast and value transmission congestion, and to understand the fundamental drivers of short- and long-term prices
- Additional information on CES is available on their website
    - http://www.ces-us.com/

Analysis Model Description/Overview – Model Overview

- The energy analysis model is the Day-Ahead Locational Market Clearing Prices Analyzer ("DAYZER") from CES
  - DAYZER is a tool that can forecast Day-Ahead hourly energy price using Locational Marginal Prices ("LMPs") (Zonal or Nodal)
    - PJM calculates LMPs in clearing the PJM energy market
  - Simulates the operation of the electricity markets, RTO dispatch procedures and calculations made by the RTOs in solving for the security constrained, least-cost unit commitment and dispatch in the day-ahead markets.
  - Forecasts the day-ahead and hourly locational market-clearing prices and congestion costs
  - Updates using the most recently available data on fuel prices, demand forecast, unit & transmission line outages, emission permits costs
  - Incorporates all the security, reliability, economic and engineering constraints on generation units and transmission system components
  - See the website for additional information
    - http://www.ces-us.com/products.html

What is Locational Marginal Pricing (LMP)?

- The "Locational Marginal Price" ("LMP") is a market-pricing approach used to manage the efficient use of the transmission system when congestion occurs on the bulk power grid
  - Transmission system congestion occurs when available, low cost supply cannot be delivered to the demand location due to transmission system limitations
- Marginal pricing is the idea that the market price of any commodity should be the cost of bringing the last unit of that commodity - the one that balances supply and demand - to market
- In electricity, LMP recognizes that this marginal price may vary at different times and "locations" based on transmission congestion
- When the lowest-priced electricity can reach all locations, prices are the same across the entire grid (e.g., all of PJM)
- When there is heavy use of the transmission system, the lowest-priced energy cannot flow freely to some locations. In that case, more expensive electricity is ordered to meet that locational demand. As a result, the locational marginal prices are higher on the receiving end of the congestion (load) and lower on the sending end

Location Marginal Pricing - PJM

- PJM Interconnection uses Locational Marginal Pricing (LMP) to establish the price of energy in the PJM wholesale electricity market
- Offers by generators to sell power are accepted in increasing price order
- Generators are selected (dispatched) by PJM with the lowest-priced offers committed and dispatched first
- Increasingly higher-priced generators are brought on-line as demand (load) increases
- Energy clearing price increases as higher-priced generators are bought on-line
  - Market-clearing prices are based on the last generating unit needed to meet demand
- With no congestion, all generators receive the same clearing price
- When congestion arise, generators receive the clearing price at their bus (node)

Sources of Model Input Data

- The energy analysis modeled the year 2013 (Jan 1, 2013 thru Dec 31, 2013) and the savings are for the entire year
- Long–term load forecast is based on historical load shape and forecasted peak demand by PJM
- Fuel prices (fuel oil and natural gas) from NYMEX
- Generator availability is based on the North American Electric Reliability Corporation ("NERC"), Generation Availability Data System ("GADS") database by unit types.
- The heat rates are based on EPA Continuous Emissions Monitoring Systems ("CEMS") data.
- Unit output is based on PJM Energy Information Agency ("EIA") data

Sources of Model Input Data

- Generation additions/retirements
  - All generation with interconnection agreements and in-service dates up to the analysis year (2013) are assumed to be in service
  - All transmission upgrades associated with the projects are also assumed to be in service
- Generation retirements are based on PJM's future deactivation list.
  - For example: Cromby 1 & 2 and Eddystone 1 are scheduled to be deactivated before 2013 and Eddystone 2 is scheduled to be deactivated on 12/31/2013
- Transmission upgrades
  - The model is similar to PJM's 2013 transmission system representation
    - All the planned projects are in service except MAPP, PATH & Branchburg-Roseland-Hudson 500 kV

Analysis Methodology

- The model was run for the year 2013 with the inputs discussed on prior pages and no new in-state generator
  - Energy costs for each Load Zone (including each NJ utility) were determined
- Then a new, efficient, combined-cycle, natural gas fired generator in southern NJ was included with the following parameters
  - Output – 640 MW (summer) / 725 MW (winter)
  - Heat Rate – 7100
- The energy costs for each Load Zone (including each NJ utility) was then determined with the new generator in-service
- The difference in the energy costs without the new generator and with the new generator is the annual energy savings NJ ratepayers can expect from a new, in-state generator in NJ

Results of Energy Savings Analysis

- The new generator operated ~61% of the year
- During this operating time, the new generator displaced more expensive units that, but for the new generator, would have cleared the energy market at a higher price
- ***The total energy savings for NJ for the 2013 model year were found to be on the order of $98 million***

Zone Name	Load Savings
Atlantic Electric	$39,884,810
JCP&L	$20,378,254
PSEG	$37,971,745
RECO	$238,265
Total	$98,473,074

Additional Benefits from New, In-State Generation

- The new combined-cycle generator displaced approximately 1621 GWh of less efficient and less environmentally-advanced coal generation

- The new combined-cycle generator displaced approximately 567 GWh of less efficient and less environmentally-advanced peaking units (gas turbines)

- The new combined-cycle generator displaced approximately 1769 GWh of less efficient and less environmentally-advanced older combined-cycle and oil-fired generation

Summary of Benefits of New, In-State Generation

- ***<u>Total Energy-only savings to NJ ratepayers ~ $98 million/year</u>***
- In addition, a typical new, ~600 MW, combined-cycle plant would create
  - Up to **<u>500 construction jobs</u>** with a payroll of ~$100 million
  - **<u>25 permanent, skilled jobs</u>** during operation
  - **<u>Additional economic benefits to the community</u>** through the purchase of local goods and services
  - **<u>New tax revenues</u>** to the local community of ~$100 million over the life of the project

Worst Case Energy Savings Analysis

- The pending legislation calls for a capacity floor price of $232.75/MW-Day fixed for the term of the contact
  - This represents a discount to the most recent wholesale capacity market clearing price
- The pending legislation would require a payment from the utilities to the generation owner ONLY in the event the wholesale capacity market clearing price fell below the floor price of $232.75/MW-Day
- Assuming the wholesale capacity market clearing price was $0.00/MW-Day (worst case), and therefore the utilities have to pay the generator the entire $232.75/MW-Day, there is still an annual net savings to the ratepayers of $43 million compared to the status quo of not building new combined-cycle generation. The savings are also in addition to the other benefits previously discussed

Bringing Energy Forward

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NEW JERSEY LAW

[Fourth Reprint]

SENATE, No. 2381

STATE OF NEW JERSEY

214th LEGISLATURE

INTRODUCED OCTOBER 18, 2010

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District 6 (Camden)

Co-Sponsored by:
Assemblymen Giblin, Amodeo, Wisniewski, Conners and Assemblywoman Rodriguez

SYNOPSIS

Establishes a long-term capacity agreement pilot program to promote construction of qualified electric generation facilities.

CURRENT VERSION OF TEXT

As amended by the General Assembly on January 10, 2011.

(Sponsorship Updated As Of: 1/11/2011)

AN ACT establishing a long-term capacity agreement pilot program to promote construction of qualified [2][in-State][2] electric generation facilities, amending and supplementing P.L.1999, c.23.

BE IT ENACTED *by the Senate and General Assembly of the State of New Jersey:*

1. The Legislature finds and declares:

a. In 2007, PJM Interconnection, L.L.C., the firm that manages the regional electric power grid, changed the method of procuring capacity in the wholesale electricity market with the implementation of the reliability pricing model [1][which, as estimated by the Board of Public Utilities, costs New Jersey ratepayers an additional $1 billion per year for capacity][1];

b. The PJM reliability pricing model [1][created additional barriers to entry for new, efficient generators, by imposing a one to three year term requirement for contracts entered into by new entrants. The maximum three-year term is insufficient to support the project financing necessary to develop new, efficient generation within the State] sought to create enhancements to the previously ineffective capacity procurement mechanism which had resulted in projected capacity deficiencies in New Jersey and other areas of the regional power grid. While the reliability pricing model has resulted in significant capacity additions in the form of new demand response resources, new energy efficiency resources, reversals of generation unit retirements, upgrades of existing generating units and certain new peaking facilities [2][in] available to the region and[2] the State, the reliability pricing model has not resulted in large additions of peaking facilities or any additions of intermediate or base load resources [2][in] available to the region and[2] the State[1];

c. The PJM reliability pricing model [1][continues to undergo structural changes that make it unreliable as an indicator of the true cost of capacity and therefore unreliable as an incentive for developing new generation] could, through structural changes, provide necessary incentives, such as the expansion of the "New Entry Price Adjustment" mechanism for the construction of new capacity, including new intermediate and base load plants, by allowing new resources to qualify and receive a guaranteed capacity price for a longer period of time. However, the implementation of similar structural changes [2][were] was[2] previously denied by FERC and any future implementation is uncertain at this time[1];

EXPLANATION – Matter enclosed in bold-faced brackets [thus] in the above bill is not enacted and is intended to be omitted in the law.

Matter underlined thus is new matter.
Matter enclosed in superscript numerals has been adopted as follows:
[1]Senate SEN committee amendments adopted November 15, 2010.
[2]Assembly ATU committee amendments adopted December 13, 2010.
[3]Assembly floor amendments adopted January 6, 2011.
[4]Assembly floor amendments adopted January 10, 2011.

d. To [1][alleviate the cost burden and barriers to new entry created by the PJM] address the lack of incentives under the[1] reliability pricing model, the construction of new, efficient [2][,in-State][2] generation must be fostered by State policy [1][to avoid higher electricity prices, higher congestion, and reliability concerns] that [2][assures that] ensures sufficient[2] generation is [2][constructed] available to the region, and thus the users[2] in the State in a timely and orderly manner[1];

e. Due to PJM's lack of authority to order new generation as a means to mitigate local electrical system reliability concerns and solve other issues related to the lack of local generation, and since only PJM has the authority to order transmission system upgrades and expansions to mitigate electrical system reliability concerns caused by transmission system overloads or the lack of local generation being developed, [1][New Jersey continues to send] New [2][Jersey's] Jersey is experiencing an electric power[2] capacity deficit [2]and high power prices that[2] may result in the loss of[1] jobs and investment [1][out-of-state to] due to the necessity for the[1] upgrade [1]of[1] the transmission system to the west of New Jersey to ensure a reliable supply of electricity and capacity from generators located outside of New Jersey;

f. As a result of a lack of new, efficient [2][, in-State][2] electric [2][generating] generation[2] facilities, New Jersey has become more reliant on [2][out-of-state][2] coal-fired power plants;

g. The PJM State of the Market Report for 2009 by the PJM Independent Market Monitor states that there [2]are[2] over 11,000 megawatts ("MW") of coal-fired units at risk of retirement due to their inability to cover their avoided costs;

h. [1][Many of New Jersey's in-State generating facilities, as a result of new emission reduction requirements, will need to have installed new emissions control technology or retire them by April 30, 2015. In one instance, the rule will have a significant impact on New Jersey's in-State fleet of electric generation facilities, as the rule imposes nitrogen oxide ("NOx") emission limits that will likely require the retirement of up to 102 combustion turbines, representing approximately 2,800 MW, and five older New Jersey steam electric generating units, representing approximately 800 MW, by April 30, 2015;

i.][1] New Jersey's in-State fleet of electric generation facilities [1][are] is[1] aging, with over 50 percent of these facilities being more than 30 years old and over 70 percent being more than 20 years old; and

[1][j.] i.[1] Fostering and incentivizing the development of [1]a limited program for[1] new [2][in-State][2] electric generation facilities [2][[1], while potential enhancements to the reliability pricing model and other PJM mechanisms are under consideration,[1]][2] will [2]help

ensure sufficient capacity to stabilize power prices to[2] assist the State's economic development [2][by creating] and create[2] [1][numerous][1] opportunities for employment in the energy sector while helping to reduce the cost and volatility of electricity prices in New Jersey.

2. Section 3 of P.L.1999, c.23 (C.48:3-51) is amended to read as follows:

3. As used in P.L.1999, c.23 (C.48:3-49 et al.):

"Assignee" means a person to which an electric public utility or another assignee assigns, sells or transfers, other than as security, all or a portion of its right to or interest in bondable transition property. Except as specifically provided in P.L.1999, c.23 (C.48:3-49 et al.), an assignee shall not be subject to the public utility requirements of Title 48 or any rules or regulations adopted pursuant thereto;

[2]"Base load electric power generation facility" means an electric power generation facility intended to be operated at a greater than 50 percent capacity factor including, but not limited to, a combined cycle power facility and a combined heat and power facility;[2]

"Base residual auction" means the auction conducted by PJM, as part of PJM's reliability pricing model, three years prior to the start of the delivery year to secure electrical capacity as necessary to satisfy the capacity requirements for that delivery year;

"Basic gas supply service" means gas supply service that is provided to any customer that has not chosen an alternative gas supplier, whether or not the customer has received offers as to competitive supply options, including, but not limited to, any customer that cannot obtain such service for any reason, including non-payment for services. Basic gas supply service is not a competitive service and shall be fully regulated by the board;

"Basic generation service" or "BGS" means electric generation service that is provided, to any customer that has not chosen an alternative electric power supplier, whether or not the customer has received offers for competitive supply options, including, but not limited to, any customer that cannot obtain such service from an electric power supplier for any reason, including non-payment for services. Basic generation service is not a competitive service and shall be fully regulated by the board;

"Basic generation service provider" or "provider" means a provider of basic generation service;

"Basic generation service transition costs" means the amount by which the payments by an electric public utility for the procurement of power for basic generation service and related ancillary and administrative costs exceeds the net revenues from the basic generation service charge established by the board pursuant to section 9 of P.L.1999, c.23 (C.48:3-57) during the transition period, together with interest on the balance at the board-approved rate, that is reflected in a deferred balance account approved by the board in an order addressing the electric public utility's unbundled rates, stranded costs, and restructuring filings pursuant to P.L.1999, c.23 (C.48:3-49 et al.). Basic generation service transition costs shall include, but are not limited to, costs of purchases from the spot market, bilateral contracts, contracts with non-utility generators, parting contracts with the purchaser of the electric public utility's divested generation assets, short-term advance purchases, and financial instruments such as hedging, forward contracts, and options. Basic generation service transition costs shall also include the payments by an electric public utility pursuant to a competitive procurement process for basic generation service supply during the transition period, and costs of any such process used to procure the basic generation service supply;

"Board" means the New Jersey Board of Public Utilities or any successor agency;

"Bondable stranded costs" means any stranded costs or basic generation service transition costs of an electric public utility approved by the board for recovery pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.), together with, as approved by the board: (1) the cost of retiring existing debt or equity capital of the electric public utility, including accrued interest, premium and other fees, costs and charges relating thereto, with the proceeds of the financing of bondable transition property; (2) if requested by an electric public utility in its application for a bondable stranded costs rate order, federal, State and local tax liabilities associated with stranded costs recovery or basic generation service transition cost recovery or the transfer or financing of such property or both, including taxes, whose recovery period is modified by the effect of a stranded costs recovery order, a bondable stranded costs rate order or both; and (3) the costs incurred to issue, service or refinance transition bonds, including interest, acquisition or redemption premium, and other financing costs, whether paid upon issuance or over the life of the transition bonds, including, but not limited to, credit enhancements, service charges, overcollateralization, interest rate cap, swap or collar, yield maintenance, maturity guarantee or other hedging agreements, equity investments, operating costs and other related fees, costs and charges, or to assign, sell or otherwise transfer bondable transition property;

"Bondable stranded costs rate order" means one or more irrevocable written orders issued by the board pursuant to P.L.1999, c.23 (C.48:3-49 et al.) which determines the amount of bondable stranded costs and the initial amount of transition bond charges authorized to be imposed to recover such bondable stranded costs, including the costs to be financed from the proceeds of the transition bonds, as well as on-going costs associated with servicing and credit enhancing the transition bonds, and provides the electric public utility specific authority to issue or cause to be issued, directly or indirectly, transition bonds through a financing entity and related matters as provided in P.L.1999, c.23, which order shall become effective immediately upon the written consent of the related electric public utility to such order as provided in P.L.1999, c.23;

"Bondable transition property" means the property consisting of the irrevocable right to charge, collect and receive, and be paid from collections of, transition bond charges in the amount necessary to provide for the full recovery of bondable stranded costs which are determined to be recoverable in a bondable stranded costs rate order, all rights of the related electric public utility under such bondable stranded costs rate order including, without limitation, all rights to obtain periodic adjustments of the related transition bond charges pursuant to subsection b. of section 15 of P.L.1999, c.23 (C.48:3-64), and all revenues, collections, payments, money and proceeds arising under, or with respect to, all of the foregoing;

"British thermal unit" or "Btu" means the amount of heat required to increase the temperature of one pound of water by one degree Fahrenheit;

"Broker" means a duly licensed electric power supplier that assumes the contractual and legal responsibility for the sale of electric generation service, transmission or other services to end-use retail customers, but does not take title to any of the power sold, or a duly licensed gas supplier that assumes the contractual and legal obligation to provide gas supply service to end-use retail customers, but does not take title to the gas;

"Buydown" means an arrangement or arrangements involving the buyer and seller in a given power purchase contract and, in some cases third parties, for consideration to be given by the buyer in order to effectuate a reduction in the pricing, or the restructuring of other terms to reduce the overall cost of the power contract, for the remaining succeeding period of the purchased power arrangement or arrangements;

"Buyout" means an arrangement or arrangements involving the buyer and seller in a given power purchase contract and, in some cases third parties, for consideration to be given by the buyer in order to effectuate a termination of such power purchase contract;

"Class I renewable energy" means electric energy produced from solar technologies, photovoltaic technologies, wind energy, fuel cells, geothermal technologies, wave or tidal action, and methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner;

"Class II renewable energy" means electric energy produced at a resource recovery facility or hydropower facility, provided that such facility is located where retail competition is permitted and provided further that the Commissioner of Environmental Protection has determined that such facility meets the highest environmental standards and minimizes any impacts to the environment and local communities;

"Co-generation" means the sequential production of electricity and steam or other forms of useful energy used for industrial or commercial heating and cooling purposes;

[2]"Combined cycle power facility" means a generation facility that combines two or more thermodynamic cycles, by producing electric power via the combustion of fuel and then routing the resulting waste heat by-product to a conventional boiler or to a heat recovery steam generator for use by a steam turbine to produce electric power, thereby increasing the overall efficiency of the generating facility;[2]

"Combined heat and power facility" or "co-generation facility" means a generation facility which produces electric energy, steam, or other forms of useful energy such as heat, which are used for industrial or commercial heating or cooling purposes. A combined heat and power facility or co-generation facility shall not be considered a public utility;

"Competitive service" means any service offered by an electric public utility or a gas public utility that the board determines to be competitive pursuant to section 8 or section 10 of P.L.1999, c.23 (C.48:3-56 or C.48:3-58) or that is not regulated by the board;

"Commercial and industrial energy pricing class customer" or "CIEP class customer" means that group of non-residential customers with high peak demand, as determined by periodic board order, which either is eligible or which would be eligible, as determined by periodic board order, to receive funds from the Retail Margin Fund established pursuant to section 9 of P.L.1999, c.23 (C.48:3-57) and for which basic generation service is hourly-priced;

"Comprehensive resource analysis" means an analysis including, but not limited to, an assessment of existing market barriers to the implementation of energy efficiency and renewable technologies that are not or cannot be delivered to customers through a competitive marketplace;

"Customer" means any person that is an end user and is connected to any part of the transmission and distribution system within an electric public utility's service territory or a gas public utility's service territory within this State;

"Customer account service" means metering, billing, or such other administrative activity associated with maintaining a customer account;

"Delivery year" or "DY" means the 12-month period from June 1st through May 31st [2]**[**and shall be**]** ,[2] numbered according to the calendar year in which it ends;

"Demand side management" means the management of customer demand for energy service through the implementation of cost-effective energy efficiency technologies, including, but not limited to, installed conservation, load management and energy efficiency measures on and in the residential, commercial, industrial, institutional and governmental premises and facilities in this State;

"Electric generation service" means the provision of retail electric energy and capacity which is generated off-site from the location at which the consumption of such electric energy and capacity is metered for retail billing purposes, including agreements and arrangements related thereto;

"Electric power generator" means an entity that proposes to construct, own, lease or operate, or currently owns, leases or operates, an electric power production facility that will sell or does sell at least 90 percent of its output, either directly or through a marketer, to a customer or customers located at sites that are not on or contiguous to the site on which the facility will be located or is located. The designation of an entity as an electric power generator for the purposes of P.L.1999, c.23 (C.48:3-49 et al.) shall not, in and of itself, affect the entity's status as an exempt wholesale generator under the Public Utility Holding Company Act of 1935, 15 U.S.C. s.79 et seq.;

"Electric power supplier" means a person or entity that is duly licensed pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.) to offer and to assume the contractual and legal responsibility to provide electric generation service to retail customers, and includes load serving entities, marketers and brokers that offer or provide electric generation service to retail customers. The term excludes an electric public utility that provides electric generation service only as a basic generation service pursuant to section 9 of P.L.1999, c.23 (C.48:3-57);

"Electric public utility" means a public utility, as that term is defined in R.S.48:2-13, that transmits and distributes electricity to end users within this State;

"Electric related service" means a service that is directly related to the consumption of electricity by an end user, including, but not limited to, the installation of demand side management measures at the end user's premises, the maintenance, repair or replacement of appliances, lighting, motors or other energy-consuming devices at the end user's premises, and the provision of energy consumption measurement and billing services;

"Electronic signature" means an electronic sound, symbol or process, attached to, or logically associated with, a contract or other record, and executed or adopted by a person with the intent to sign the record;

"Eligible generator" means a developer of a [2][new, natural gas fired, combined-cycle] base load[2] [4]or mid-merit[4] electric power [2][generating] generation[2] facility [2][with a net summer output rating of 100 megawatts or larger, that is physically located within the State of New Jersey,] including, but not limited to, an on-site generation facility that qualifies as a capacity resource under PJM criteria [4][but exclusive of a combustion turbine generation facility that is directly interconnected with the electric public utilities' transmission or distribution system,[2]][4] and that commences construction [4][[2]of new generation[2]][4] after the effective date of P.L. , c. (C.) (pending before the Legislature as this bill);

"Energy agent" means a person that is duly registered pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.), that arranges the sale of retail electricity or electric related services or retail gas supply or gas related services between government aggregators or private aggregators and electric power suppliers or gas suppliers, but does not take title to the electric or gas sold;

"Energy consumer" means a business or residential consumer of electric generation service or gas supply service located within the territorial jurisdiction of a government aggregator;

"Energy efficiency portfolio standard" means a requirement to procure a specified amount of energy efficiency or demand side management resources as a means of managing and reducing energy usage and demand by customers;

"Energy year" or "EY" means the 12-month period from June 1st through May 31st [2][and shall be] ,[2] numbered according to the calendar year in which it ends;

"Federal Energy Regulatory Commission" or "FERC" means the federal agency established pursuant to 42 U.S.C. s.7171 et seq. to regulate the interstate transmission of electricity, natural gas, and oil;

"Financing entity" means an electric public utility, a special purpose entity, or any other assignee of bondable transition property, which issues transition bonds. Except as specifically provided in P.L.1999, c.23 (C.48:3-49 et al.), a financing entity which is not itself an electric public utility shall not be subject to the public utility requirements of Title 48 or any rules or regulations adopted pursuant thereto;

"Gas public utility" means a public utility, as that term is defined in R.S.48:2-13, that distributes gas to end users within this State;

"Gas related service" means a service that is directly related to the consumption of gas by an end user, including, but not limited to, the installation of demand side management measures at the end user's premises, the maintenance, repair or replacement of appliances or other energy-consuming devices at the end user's premises, and the provision of energy consumption measurement and billing services;

"Gas supplier" means a person that is duly licensed pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.) to offer and assume the contractual and legal obligation to provide gas supply service to retail customers, and includes, but is not limited to, marketers and brokers. A non-public utility affiliate of a public utility holding company may be a gas supplier, but a gas public utility or any subsidiary of a gas utility is not a gas supplier. In the event that a gas public utility is not part of a holding company legal structure, a related competitive business segment of that gas public utility may be a gas supplier, provided that related competitive business segment is structurally separated from the gas public utility, and provided that the interactions between the gas public utility and the related competitive business segment are subject to the affiliate relations standards adopted by the board pursuant to subsection k. of section 10 of P.L.1999, c.23 (C.48:3-58);

"Gas supply service" means the provision to customers of the retail commodity of gas, but does not include any regulated distribution service;

"Government aggregator" means any government entity subject to the requirements of the "Local Public Contracts Law," P.L.1971, c.198 (C.40A:11-1 et seq.), the "Public School Contracts Law," N.J.S.18A:18A-1 et seq., or the "County College Contracts Law," P.L.1982, c.189 (C.18A:64A-25.1 et seq.), that enters into a written contract with a licensed electric power supplier or a licensed gas supplier for: (1) the provision of electric generation service, electric related service, gas supply service, or gas related service for its own use or the use of other government aggregators; or (2) if a municipal or county government, the provision of electric generation service or gas supply service on behalf of business or residential customers within its territorial jurisdiction;

"Government energy aggregation program" means a program and procedure pursuant to which a government aggregator enters into a written contract for the provision of electric generation service or gas supply service on behalf of business or residential customers within its territorial jurisdiction;

"Governmental entity" means any federal, state, municipal, local or other governmental department, commission, board, agency, court, authority or instrumentality having competent jurisdiction;

"Greenhouse gas emissions portfolio standard" means a requirement that addresses or limits the amount of carbon dioxide emissions indirectly resulting from the use of electricity as applied to any electric power suppliers and basic generation service providers of electricity;

[2]"Incremental auction" means an auction conducted by PJM, as part of PJM's reliability pricing model, prior to the start of the delivery year to secure electric capacity as necessary to satisfy the capacity requirements for that delivery year, that is not otherwise provided for in the base residual auction;[2]

"Leakage" means an increase in greenhouse gas emissions related to generation sources located outside of the State that are not subject to a state, interstate or regional greenhouse gas emissions cap or standard that applies to generation sources located within the State;

[2]"Locational deliverability area" or "LDA" means one or more of the zones within the PJM region which are used to evaluate area

transmission constraints and reliability issues including electric public utility company zones, sub-zones, and combinations of zones.[2]

"Long-term capacity agreement pilot program" or "LCAPP" means a [2][one-time][2] pilot program established by the board that [4][is limited to] includes[4] participation by eligible generators, to seek offers [2][no later than February 4, 2011,][2] for financially-settled standard offer capacity agreements [2][that extend for a term of not less than 15 years, to quickly and safely construct new, natural gas fired, combined-cycle electric power generating facilities with a net summer output rating of 100 megawatts or larger within the State] with eligible generators pursuant to the provisions of P.L. , c. (C.) (pending before the Legislature as this bill)[2];

"Market transition charge" means a charge imposed pursuant to section 13 of P.L.1999, c.23 (C.48:3-61) by an electric public utility, at a level determined by the board, on the electric public utility customers for a limited duration transition period to recover stranded costs created as a result of the introduction of electric power supply competition pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.);

"Marketer" means a duly licensed electric power supplier that takes title to electric energy and capacity, transmission and other services from electric power generators and other wholesale suppliers and then assumes the contractual and legal obligation to provide electric generation service, and may include transmission and other services, to an end-use retail customer or customers, or a duly licensed gas supplier that takes title to gas and then assumes the contractual and legal obligation to provide gas supply service to an end-use customer or customers;

[4]"Mid-merit electric power generation facility" means a generation facility that operates at a capacity factor between baseload generation facilities and peaker generation facilities;[4]

"Net proceeds" means proceeds less transaction and other related costs as determined by the board;

"Net revenues" means revenues less related expenses, including applicable taxes, as determined by the board;

"Offshore wind energy" means electric energy produced by a qualified offshore wind project;

"Offshore wind renewable energy certificate" or "OREC" means a certificate, issued by the board or its designee, representing the environmental attributes of one megawatt hour of electric generation from a qualified offshore wind project;

"Off-site end use thermal energy services customer" means an end use customer that purchases thermal energy services from an on-site generation facility, combined heat and power facility, or co-generation facility, and that is located on property that is separated from the property on which the on-site generation facility, combined heat and power facility, or co-generation facility is located by more than one easement, public thoroughfare, or transportation or utility-owned right-of-way;

"On-site generation facility" means a generation facility, and equipment and services appurtenant to electric sales by such facility to the end use customer located on the property or on property contiguous to the property on which the end user is located. An on-site generation facility shall not be considered a public utility. The property of the end use customer and the property on which the on-site generation facility is located shall be considered contiguous if they are geographically located next to each other, but may be otherwise separated by an easement, public thoroughfare, transportation or utility-owned right-of-way, or if the end use customer is purchasing thermal energy services produced by the on-site generation facility, for use for heating or cooling, or both, regardless of whether the customer is located on property that is separated from the property on which the on-site generation facility is located by more than one easement, public thoroughfare, or transportation or utility-owned right-of-way;

"Person" means an individual, partnership, corporation, association, trust, limited liability company, governmental entity or other legal entity;

<u>“PJM Interconnection, L.L.C.” or “PJM” means the privately-held, limited liability corporation that is a FERC-approved Regional Transmission Organization</u> [2]<u>, or its successor,</u>[2] <u>that manages the regional, high-voltage electricity grid serving all or parts of 13 states including New Jersey and the District of Columbia, operates the regional competitive wholesale electric market, manages the regional transmission planning process, and establishes systems and rules to ensure that the regional and in-State energy markets operate fairly and efficiently;</u>

"Private aggregator" means a non-government aggregator that is a duly-organized business or non-profit organization authorized to do business in this State that enters into a contract with a duly licensed electric power supplier for the purchase of electric energy and capacity, or with a duly licensed gas supplier for the purchase of gas supply service, on behalf of multiple end-use customers by combining the loads of those customers;

"Public utility holding company" means: (1) any company that, directly or indirectly, owns, controls, or holds with power to vote, ten percent or more of the outstanding voting securities of an electric public utility or a gas public utility or of a company which is a public utility holding company by virtue of this definition, unless the Securities and Exchange Commission, or its successor, by order declares such company not to be a public utility holding company under the Public Utility Holding Company Act of 1935, 15 U.S.C. s.79 et seq., or its successor; or (2) any person that the

Securities and Exchange Commission, or its successor, determines, after notice and opportunity for hearing, directly or indirectly, to exercise, either alone or pursuant to an arrangement or understanding with one or more other persons, such a controlling influence over the management or policies of an electric public utility or a gas public utility or public utility holding company as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties, and liabilities imposed in the Public Utility Holding Company Act of 1935 or its successor;

"Qualified offshore wind project" means a wind turbine electricity generation facility in the Atlantic Ocean and connected to the electric transmission system in this State, and includes the associated transmission-related interconnection facilities and equipment, and approved by the board pursuant to section 3 of P.L.2010, c.57 (C.48:3-87.1);

"Regulatory asset" means an asset recorded on the books of an electric public utility or gas public utility pursuant to the Statement of Financial Accounting Standards, No. 71, entitled "Accounting for the Effects of Certain Types of Regulation," or any successor standard and as deemed recoverable by the board;

"Related competitive business segment of an electric public utility or gas public utility" means any business venture of an electric public utility or gas public utility including, but not limited to, functionally separate business units, joint ventures, and partnerships, that offers to provide or provides competitive services;

"Related competitive business segment of a public utility holding company" means any business venture of a public utility holding company, including, but not limited to, functionally separate business units, joint ventures, and partnerships and subsidiaries, that offers to provide or provides competitive services, but does not include any related competitive business segments of an electric public utility or gas public utility;

"Reliability pricing model" or "RPM" means PJM's capacity-market model, and its successors, that secures capacity on behalf of electric load serving entities to satisfy load obligations not satisfied through the output of electric generation facilities owned by those entities [2],[2] [1]or otherwise secured by those entities through bilateral contracts[1] ;

"Renewable energy certificate" or "REC" means a certificate representing the environmental benefits or attributes of one megawatt-hour of generation from a generating facility that produces Class I or Class II renewable energy, but shall not include a solar renewable energy certificate or an offshore wind renewable energy certificate;

"Resource clearing price" or "RCP" means the clearing price established for the applicable locational deliverability area by the base residual auction [1]or incremental auction[1] [2], as determined by the optimization algorithm for each auction,[2] conducted by PJM as part of PJM's reliability pricing model;

"Resource recovery facility" means a solid waste facility constructed and operated for the incineration of solid waste for energy production and the recovery of metals and other materials for reuse;

"Restructuring related costs" means reasonably incurred costs directly related to the restructuring of the electric power industry, including the closure, sale, functional separation and divestiture of generation and other competitive utility assets by a public utility, or the provision of competitive services as such costs are determined by the board, and which are not stranded costs as defined in P.L.1999, c.23 (C.48:3-49 et al.) but may include, but not be limited to, investments in management information systems, and which shall include expenses related to employees affected by restructuring which result in efficiencies and which result in benefits to ratepayers, such as training or retraining at the level equivalent to one year's training at a vocational or technical school or county community college, the provision of severance pay of two weeks of base pay for each year of full-time employment, and a maximum of 24 months' continued health care coverage. Except as to expenses related to employees affected by restructuring, "restructuring related costs" shall not include going forward costs;

"Retail choice" means the ability of retail customers to shop for electric generation or gas supply service from electric power or gas suppliers, or opt to receive basic generation service or basic gas service, and the ability of an electric power or gas supplier to offer electric generation service or gas supply service to retail customers, consistent with the provisions of P.L.1999, c.23 (C.48:3-49 et al.);

"Retail margin" means an amount, reflecting differences in prices that electric power suppliers and electric public utilities may charge in providing electric generation service and basic generation service, respectively, to retail customers, excluding residential customers, which the board may authorize to be charged to categories of basic generation service customers of electric public utilities in this State, other than residential customers, under the board's continuing regulation of basic generation service pursuant to sections 3 and 9 of P.L.1999, c.23 (C.48:3-51 and 48:3-57), for the purpose of promoting a competitive retail market for the supply of electricity;

"Shopping credit" means an amount deducted from the bill of an electric public utility customer to reflect the fact that such customer has switched to an electric power supplier and no longer takes basic generation service from the electric public utility;

"Social program" means a program implemented with board approval to provide assistance to a group of disadvantaged customers, to provide protection to consumers, or to accomplish a particular societal goal, and includes, but is not limited to, the winter moratorium program, utility practices concerning "bad debt" customers, low income assistance, deferred payment plans, weatherization programs, and late payment and deposit policies, but does not include any demand side management program or any environmental requirements or controls;

"Societal benefits charge" means a charge imposed by an electric public utility, at a level determined by the board, pursuant to, and in accordance with, section 12 of P.L.1999, c.23 (C.48:3-60);

"Solar alternative compliance payment" or "SACP" means a payment of a certain dollar amount per megawatt hour (MWh) which an electric power supplier or provider may submit to the board in order to comply with the solar electric generation requirements under section 38 of P.L.1999, c.23 (C.48:3-87);

"Solar renewable energy certificate" or "SREC" means a certificate issued by the board or its designee, representing one megawatt hour (MWh) of solar energy that is generated by a facility connected to the distribution system in this State and has value based upon, and driven by, the energy market;

"Standard offer capacity agreement" or "SOCA" means a financially-settled transaction agreement, approved by board order, that provides for [1]**[**an**]**[1] eligible [1]**[**generator**]** generators [2]**[**: (1)[1]**]**[2] to receive [2]**[**a payment**]** payments[2] from [2]**[**one or more**]** the[2] electric public utilities [2]**[**, in the event the SOCP is greater than the [1]base residual auction[1] RCP for any applicable delivery year, [1]and[1] that [1]**[**provides for**]**[1] such payment [1]**[**to be**]** is[1] equal to the difference between the SOCP and the [1]base residual auction[1] RCP multiplied by the contract capacity [1]**[**, that provides**]** ; and (2) to remit a payment to one or more electric public utilities for the benefit of ratepayers, in the event the base residual auction RCP is greater than $290 per megawatt day for any applicable delivery year, and that such payment is equal to the result of the difference between the base residual auction RCP and $290 per megawatt day for the applicable delivery year multiplied by the contract capacity. The SOCA shall provide[1]**]**[2] for a defined amount of electric capacity for [4]**[**the term of the transaction of not less than**]** a term to be determined by the board but not to exceed 15 years,[4] [2]**[**15 years,**]** [4]**[**seven years or not more than 10 years,[2]**]**[4] and [1]**[**that provides**]**[1] for [1]**[**such payment**]** [2]such[2] payments [2]**[**made pursuant to paragraph (1)[1]**]**[2] to be a fully non-bypassable charge, with such an order, once issued, being irrevocable;

"Standard offer capacity price" or "SOCP" means the capacity price that is fixed for the term of the SOCA and [2]which[2] is the [2]**[**minimum**]**[2] price to be received by [1]**[**an**]**[1] eligible [1]**[**generator**]** generators[1] under a board-approved SOCA;

"Stranded cost" means the amount by which the net cost of an electric public utility's electric generating assets or electric power purchase commitments, as determined by the board consistent with the provisions of P.L.1999, c.23 (C.48:3-49 et al.), exceeds the market value of those assets or contractual commitments in a competitive supply marketplace and the costs of buydowns or buyouts of power purchase contracts;

"Stranded costs recovery order" means each order issued by the board in accordance with subsection c. of section 13 of P.L.1999, c.23 (C.48:3-61) which sets forth the amount of stranded costs, if any, the board has determined an electric public utility is eligible to recover and collect in accordance with the standards set forth in section 13 of P.L.1999, c.23 (C.48:3-61) and the recovery mechanisms therefor;

"Thermal efficiency" means the useful electric energy output of a facility, plus the useful thermal energy output of the facility, expressed as a percentage of the total energy input to the facility;

"Transition bond charge" means a charge, expressed as an amount per kilowatt hour, that is authorized by and imposed on electric public utility ratepayers pursuant to a bondable stranded costs rate order, as modified at any time pursuant to the provisions of P.L.1999, c.23 (C.48:3-49 et al.);

"Transition bonds" means bonds, notes, certificates of participation or beneficial interest or other evidences of indebtedness or ownership issued pursuant to an indenture, contract or other agreement of an electric public utility or a financing entity, the proceeds of which are used, directly or indirectly, to recover, finance or refinance bondable stranded costs and which are, directly or indirectly, secured by or payable from bondable transition property. References in P.L.1999, c.23 (C.48:3-49 et al.) to principal, interest, and acquisition or redemption premium with respect to transition bonds which are issued in the form of certificates of participation or beneficial interest or other evidences of ownership shall refer to the comparable payments on such securities;

"Transition period" means the period from August 1, 1999 through July 31, 2003;

"Transmission and distribution system" means, with respect to an electric public utility, any facility or equipment that is used for the transmission, distribution or delivery of electricity to the customers of the electric public utility including, but not limited to, the land, structures, meters, lines, switches and all other appurtenances thereof and thereto, owned or controlled by the electric public utility within this State; and

"Universal service" means any service approved by the board with the purpose of assisting low-income residential customers in obtaining or retaining electric generation or delivery service.

(cf: P.L.2010, c.57, s.1)

3. (New section) Notwithstanding any provisions of the "Administrative Procedure Act," P. L. 1968, c.410 (C.52:14B-1 et seq.) to the contrary, the board shall [2][, within 10 days of the effective date of P.L. , c. (C.) (pending before the Legislature as this bill),][2] initiate [2]and complete[2] a proceeding [2][on] in accordance with[2] the schedule set forth in this section [2][allowing such proceeding to be completed][2] to support the commencement of the LCAPP [2][no later than January 31, 2011, and shall adopt, after notice, the opportunity for comment, and public hearing on the schedule set forth in this section, the following requirements for the LCAPP][2]:

[2][a. the establishment of the LCAPP that allows for offering financially-settled SOCAs for the purpose of facilitating the development of eligible generators;

b. the establishment of the LCAAP on the following schedule:

(1) the board shall complete the process to develop the SOCA no later than January 1, 2011; and

(2) SOCAs resulting from this process shall be awarded, executed and approved by the board with a written board order no later than February 25, 2011;

c. the participation of selected eligible generators with board approved, executed SOCAs in and clearing of the base residual auction conducted by PJM and scheduled to commence on May 2, 2011, as part of PJM's reliability pricing model for the delivery year 2015;

d. that it be limited to eligible generators in order to maximize economic benefits and job creation in the State;

e. that electric public utilities shall procure at least 500 megawatts and not more than [1][1500] 1,000[1] megawatts of financially-settled SOCAs from the eligible generators;

f. [1][that no single eligible generator or its affiliate may enter into more than 900 megawatts of financially-settled standard offer capacity agreements;

g.][1]]

a. The board shall initiate [4][the proceeding within 30 days of the effective date of P.L. , c. (C.) (pending before the Legislature as this bill),][4] and allow such proceeding to be completed no later than [4][March 1, 2011] 60 days after the effective date of P.L , c. (C.) (pending before the Legislature as this bill)[4] to allow for the commencement of the LCAPP. The SOCA or SOCAs resulting from that proceeding shall be awarded [4][,] and[4] executed [4][and approved by the board with a written board order][4] no later than [4][April 15, 2011] 30 days after the approval of the form of the SOCA or SOCAs[4]. The LCAPP shall require selected eligible generators with board approved and executed SOCAs to participate and be accepted as a capacity resource in the base residual auction conducted by PJM [4][and scheduled to commence either on May 2, 2011, as part of PJM's reliability pricing model for the delivery year 2015, or May 2012, as part of PJM's reliability pricing model for the delivery year 2016][4];

b. The board shall require [4][, within 10 days of the effective date of P.L. , c. (C.)(pending before the Legislation as this bill)][4] that the electric public utilities within the State retain an agent [4], with the approval of the board,[4] to administer the LCAPP. The agent retained in accordance with this section shall [4], on behalf of the board,[4] be responsible for:

(1) assisting the board with the establishment of the LCAPP that allows for offering financially-settled SOCAs for the purpose of facilitating the development of eligible generators;

(2) prequalifying eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date [4][. Eligible generators must prequalify by April 1, 2011 and seek a SOCA by submitting an offer price and term by April 1, 2011][4] ; and

(3) recommending to the board the selection of winning eligible generators based on the net benefit to ratepayers of each prequalified eligible generator's offer price and term. [4][Eligible generators that are located in an "area in need of redevelopment" in accordance with the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.) or a brownfield development area in accordance with the "Brownfield and Contaminated Site Remediation Act," P.L.2005, c.223 (C.58:10B-1 et seq.), and eligible] Eligible[4] generators that can enter commercial operation for delivery year 2015 [4][, shall have] are to be provided with[4] a weighted preference in addition to the net benefit [4][to ratepayers ranking provided for in this subsection] ratepayer test[4] . Eligible generators shall also indicate the amount of capacity they are offering in the LCAPP.

c. In the proceeding initiated by the board pursuant to this section, the board shall adopt, after notice, the opportunity for comment, and public hearing, an order addressing the following requirements for the LCAPP:

(1) that electric public utilities shall procure [3][1,000] 2,000[3] megawatts of financially-settled SOCAs from eligible generators, which shall include new generation capacity [4][for the 2015 or 2016 delivery year][4];

(2)[2] that eligible generators participating in the LCAPP shall be required to offer [2][the maximum] a[2] quantity, in megawatts, [2]offer a price per megawatt-day, and a term[2] of the SOCA [2][at the standard offer [1]capacity[1] price of $232.75 per megawatt per day, which represents a discount to the most recent clearing price established by the base residual auction conducted by the PJM in May, 2010 as part of the PJM's reliability pricing model] to be evaluated by the agent and approved by the board[2];

[1][h.] [2][g.[1]] (3)[2] that [2], taking into consideration the agent's recommendation,[2] the board [2][select] approve the selected[2] [1][an][1] eligible [1][generator] generators[1] from among the [2]qualified[2] eligible generators participating in the LCAPP for the award of [2][a][2] board-approved long-term financially-settled [2][SOCA] SOCAs[2] for a term [4][of not less than] to be determined by the board but not to exceed 15 years[4] [2][15 years] [4][seven years or more than 10 years at the offer price and term of each selected eligible generator[2]][4] ;[1][.][1]

[2](4) that the board establish a method and the contract terms for providing for selected eligible generators to receive payments from the electric public utilities for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the SOCP is greater than the RCP for any applicable delivery year and for providing for electric public utilities to receive refunds from the selected eligible generators for the difference between the SOCP and the RCP multiplied by the SOCA capacity in the event the RCP is greater than the SOCP for any applicable delivery year;

(5) that no single eligible generator or its affiliate may enter into more than 700 megawatts of financially-settled standard offer capacity agreements;

(6) that the board establish criteria associated with the prequalification of eligible generators for participation in the LCAPP through a showing of environmental, economic, and community benefits, and through demonstration of reasonable certainty of completion of development, construction and permitting activities necessary to meet the desired in-service date;

(7) that the board establish a method for evaluating and comparing the net [4][present][4] value [4]to ratepayers[4] of each eligible generator's offer price and term;

(8) that the board establish a method for providing [4][for a weighted preference for eligible generators in an "area in need of redevelopment" in accordance with the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.) or a brownfield development area in accordance with the "Brownfield and Contaminated Site Remediation Act," P.L.2005, c.223 (C.58:10B-1 et seq.), and][4] a weighted preference for eligible generators that can enter commercial operation for delivery year 2015;[2]

[1][i.] [2][h.[1] that the selection of winning eligible generators give preference to those eligible generators located in "areas in need of

redevelopment” in accordance with the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 et seq.), that based on the board’s determination, can provide the greatest environmental, economic, and community benefits, and can demonstrate certainty of completion of development and permitting activities necessary to meet the desired in-service date;

[1][j.] i.[1]] (9)[2] that [1][an][1] eligible [1][generator] generators[1] [2][selected] approved[2] by the board, enter into a SOCA with each of the State’s four electric public utilities provided that each electric public utility shall pay [2]or receive refunds pursuant to[2] [1][a] an annually calculated[1] load-ratio share [2]of the capacity[2] of the SOCA [2][price][2] based upon each electric public utility’s annual forecasted peak demand as determined by PJM;

[1][k.] [2][j.[1]] (10)[2] that the resulting SOCA shall bind the electric public utilities to the board approved SOCAs with [1][a][1] selected eligible [1][generator] generators[1] for [2][not less than 15 years] the term of the SOCA[2];

[1][l.] [2][k.[1]] (11)[2] that the selected eligible generators with executed SOCAs shall offer the capacity, electricity, and ancillary services into the PJM wholesale markets as required by the PJM market rules; [2]and[2]

[1][m.] [2][l.[1]] (12)[2] that selected eligible generators with executed SOCAs shall participate in and clear the annual base residual auction conducted by the PJM as part of [2][PJM’s] its[2] reliability pricing model for each delivery year of the entire term of the agreement [2][;] .[2]

[1][n.] [2][m.[1] that the] d. The[2] board shall order the full recovery of all costs associated with the electric public utilities’ resulting SOCAs [2], and the costs of the agent retained pursuant to subsection b. of this section,[2] from ratepayers through a non-bypassable, irrevocable charge;

[2][(1) notwithstanding] e. Notwithstanding[2] any other provision of law, each [2][LCAPP standard offer capacity agreement] SOCA[2] shall become irrevocable upon the issuance of such order [2]approving a SOCA[2]; and

[2][(2) neither] f. Neither[2] the board or any other governmental entity shall have the authority, directly or indirectly, legally or equitably, to rescind, alter, repeal, modify or amend [2]a SOCA or[2] an LCAPP cost rate order, to revalue, re-evaluate [2],[2] or revise the amount of LCAPP costs, or to determine that the LCAPP charges or the revenues to recover the LCAPP charges for such SOCAs are unjust or unreasonable [2][; and

[1][o.] n.[1] that the board shall have complete discretion to approve any and all SOCAs resulting from the LCAPP][2].

[2]4. (New section) If one or more provisions in P.L.   , c. (C.)(pending before the Legislation as this bill) are challenged in an administrative or judicial proceeding, the board may suspend the applicability of the challenged provision or provisions during the pendency of those proceedings until final resolution of the challenge and any appeals, and shall issue such orders and take such other actions as it deems appropriate to ensure that the provisions that are not challenged are implemented expeditiously to achieve the public purposes of P.L.   , c.   (C.   )(pending before the Legislature as this bill).[2]

[2]5. (New section) Notwithstanding the provisions of any other law, rule, regulation, or order to the contrary, gas public utilities shall not impose a societal benefits charge pursuant to section 12 of P.L.1999, c.23 (C.48:3-60), or any other charge designed to recover the costs for social, energy efficiency, conservation, environmental or renewable energy programs, on natural gas delivery service or commodity that is used to generate electricity that is sold for resale.[2]

[2][4.] 6.[2] This act shall take effect immediately.

MARYLAND RFP

(attachments omitted)

STATE OF MARYLAND

PUBLIC SERVICE COMMISSION

December 29, 2010

In the Matter of Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service	* * * * * *	Case No. 9214

* * * * *

NOTICE OF COMMENT PERIOD ON REQUEST FOR PROPOSALS FOR NEW GENERATING FACILITIES

To: Parties of Record and Interested Persons

On September 29, 2009, the Commission issued Order No. 82936, which initiated this proceeding and invited parties to file proposals for Maryland-located new generating facilities by December 1, 2009. On October 9, 2009, Technical Staff ("Staff") of the Public Service Commission ("Commission") filed a letter asking that the Commission offer some clarification regarding the scope of proposals requested. In its letter, Staff provided a list of additional information that Staff recommended, should be contained in the proposals submitted pursuant to the Order for the Commission's review. On October 15, 2009, the Commission set a comment period to allow parties and interested persons an opportunity to comment on Staff's recommendations, or to provide any additional elements that any party or interested person believed would be helpful to the Commission's review of the proposals. On November 10, 2009, the Commission issued a Notice tolling the date by which any proposals would be required to be filed in this matter.

After reviewing the comments made as a result of the Notice issued in the matter on October 15, 2009, the Commission determined that a more formal request for proposals ("RFP") is required to seek offers for new generating facilities in or around Maryland, including the possibility that electric distribution companies ("EDCs") could be required to enter into long term contracts with persons that construct a new generating facility in or around Maryland. The Commission has prepared a draft RFP, including form of contracts, to solicit offers from persons for new generating facilities in or around Maryland, a copy of which is attached to this Notice. In addition, the Commission anticipates that it will order the EDCs to submit proposals to construct, acquire, or lease, and operate new generation capacity resources in or around Maryland that meet the requirements of the RFP issued in this matter. Prior to issuing the RFP,

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MDRS: 1-800-735-2258 (TTY/Voice) • Website: www.psc.state.md.us/psc/

the Commission is setting a comment period to allow parties to the proceeding and interested persons to review the draft and provide any comments on, or suggested edits or revisions to, the draft RFP. The fact that the Commission issued this Notice or has prepared a draft RFP should not be construed as a finding by the Commission that new generation is required or that the Commission has decided to order any party to construct, acquire, lease or operate new capacity resources in or around Maryland.

Accordingly, any party or interested person shall file an original and seventeen paper copies, and an electronic version, of its comments to Terry J. Romine, Executive Secretary, Maryland Public Service Commission, William Donald Schaefer Tower, 6 St. Paul Street, Baltimore, Maryland 21202 by Friday, January 28, 2011. Five of the paper copies shall be three-hole punched. The Commission encourages persons to file the electronic public version of the comments via the Commission's "e-file" system which can be accessed via the Commission's website, www.psc.state.md.us.

By Direction of the Commission,

/s/ T. J. Romine

Terry J. Romine
Executive Secretary

REQUEST FOR PROPOSALS
FOR
GENERATION CAPACITY RESOURCES
UNDER LONG-TERM CONTRACT

DATED
[DATE]

Request for Proposals For Generation Capacity Resources under Long-Term Contracts

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1 INTRODUCTION

Pursuant to Sections 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, the "Customer Choice Act") of the Maryland Public Utilities Article, *Annotated Code of Maryland* ("PUA") the Maryland Public Service Commission (PSC or Commission) hereby directs Baltimore Gas and Electric Company (BGE), Delmarva Power and Light Company (DP&L), The Potomac Edison Company d/b/a Allegheny Power (AP), and Potomac Electric Power Company (Pepco) (collectively referred to as the Maryland electric distribution companies or "EDCs") to issue this Request For Proposals (RFP) for Capacity, Energy, Ancillary Services, and, if applicable, Maryland Tier 1 Renewable Energy Credits (RECs) (collectively referred to as Products).[1] This RFP supplements other reliability initiatives undertaken by the Commission in Case 9149.[2]

The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers. During the Commission's Summer 2007 Electricity Planning Conference, PJM Interconnection L.L.C. (PJM) first reported to the Commission the possibility of power supply shortages on hot summer days beginning in 2011. More recently, as part of the Commission's ongoing review of electricity supply and demand in Maryland, PJM updated its projections on Maryland's potential capacity "gap." In a March 2, 2010 presentation provided by PJM as part of Case No. 9149, PJM opined that the Capacity Emergency Transfer Limit (CETL) of the Mid-Atlantic area, which includes Maryland's Eastern Shore and the Pepco load delivery area was limited

[1] PUA § 7-510 provides for the phased implementation of customer choice. PUA § 7-510(c) details the obligations of electric companies and the Commission in that regard. PUA § 7-510(c)(4)(ii)1.B provides that "Under the obligation to provide standard offer service …the Commission, by regulation or order, and in a manner that is designed to obtain the best price for residential and small commercial customers in light of market conditions at the time of procurement, and the need to protect these customers from excessive price increases… may require or allow an investor-owned electric company to procure electricity for these customers directly from an electricity supplier through one or more bilateral contracts outside the competitive process." PUA Article § 7-510(c)(4)(ii)2.A allows, at the Commission's direction, an investor-owned electric company to solicit bids "to supply anticipated standard offer service load for residential and small commercial customers as part of a portfolio of blended wholesale supply contracts of short, medium or long terms and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner." PUA § 7-510(c)(6) permits the Commission to require an investor-owned electric company to construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply.

[2] "In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland."

by the Pleasant View 500/230 kV transformer. In a follow-up letter to the Commission, dated March 18, 2010, PJM reiterated its commitment to further analysis of the facilities limiting deliverability into the Pepco and Mid-Atlantic areas. PJM noted that removing the Pleasant View constraint would increase the CETL into these two areas. And at the April 14, 2010 Transmission Expansion Advisory Committee (TEAC) meeting, PJM reported that it had conducted preliminary load deliverability thermal and voltage analyses on selected Locational Deliverability Areas (LDAs) which include MAAC, Southwest MAAC (SWMAAC) and Pepco. The results show reactive deficiencies in 2015 with MAAC and the other areas being voltage limited.

The Pleasant View constraint is the most recent example of how resource and transmission limitations, often outside of Maryland, constrain the availability of resources to serve Maryland's needs. Although the Commission recognizes and appreciates PJM's role in planning regional transmission solutions, Maryland law directs this Commission to ensure an adequate and reliable supply of electricity to Maryland citizens. Where that supply may fall short, Public Utilities Article § 7-510(c)(6) authorizes this Commission to require investor-owned electric companies in Maryland to "construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply." The reactive deficiencies PJM is predicting for 2015 would, if not cured, limit the amount of electricity available to import into Maryland. And that potential capacity shortage could be exacerbated further if new emissions regulations being considered by the United States Environmental Protection Agency were to cause coal-fired plants in PJM to cease operations. For all of these reasons, Maryland law requires this Commission to consider the impact of these potential constraints and shortfalls upon Maryland ratepayers and identify all possible mitigating solutions, including new generation. Because market forces have not produced new generation in our region, the Commission may need to invoke its authority under § 7-510(c)(6) if, after an evidentiary hearing, the record in this case demonstrates that a projected capacity shortfall in the Delivery Year may affect Maryland and that ordering the construction, acquisition , lease or operation of additional capacity resources would satisfy the long-term anticipated demand in Maryland for Standard Offer Service or other electricity supply.

Throughout this RFP, capitalized terms used but not defined herein have the meanings ascribed to such terms in PJM's Reliability Assurance Agreement (RAA) or PJM's Open Access Transmission Tariff (OATT), or in the model agreements (the "Agreements") for cost-of-service pricing or fixed/indexed pricing (see Section 4 below). This RFP is issued by and will be administered by the EDCs. The Commission will evaluate all proposals submitted hereunder and by the EDCs.

The Commission is solely responsible for determining contract awards under this RFP, and may authorize one or more of the Maryland EDCs to enter into a long-term Contract for Differences as Buyer, or may direct one or more EDCs to construct new generation, if and when it determines a need for additional generation in Maryland. The Commission will conduct an evidentiary hearing to evaluate these issues.

2 PRODUCTS REQUESTED

2.1 PRODUCT DEFINITION

The Commission is requesting proposals for Products, which must include Capacity, Energy and any available Ancillary Services and which may include Maryland Tier 1 RECs. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located in or around Maryland so long as such Generation Capacity Resource is interconnected to the System such that the Generation Capacity Resource's output is infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion. Generation Capacity Resources may be conventional or renewable generation technology, but Generation Capacity Resources do not include demand resources or energy efficiency resources. Generation Capacity Resources may include new up-rates of existing generation resources, but only the incremental portion of such generation resources may be considered a Generation Capacity Resource.

Generation Capacity Resources offered can be either Dispatchable or Non-Dispatchable.

2.1.1 DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Dispatchable Generation Capacity Resource will be dispatched in the PJM Day Ahead Market (DAM) or Real Time Market (RTM) based on an offering that reflects actual fuel costs plus non-fuel variable operation and maintenance (O&M) costs, and by the actual availability of the unit or units which make up the Dispatchable Generation Capacity Resource. Each such unit shall be offered into the DAM or RTM using the same definition of total variable cost as used to determine the Supplier's compensation for energy, as set forth in Article 6 of the Agreements. If appropriate, Supplier shall also offer relevant Ancillary Service products into the PJM markets so as to optimize net revenues.

2.1.2 NON-DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Non-Dispatchable Generation Capacity Resource will be determined by the availability of a natural energy source (such as wind or solar) and the availability of the conversion unit or units that make up the Non-Dispatchable Generation Capacity Resource. Any ability to control the schedule of the energy output from a Non-Dispatchable Generation Capacity Resource is assumed to be very limited.

2.2 TERM OF AGREEMENT

Respondents may submit proposals to commit Generation Capacity Resources for an initial term of a maximum period of twenty years beginning no earlier than June 1, 2015 and no later than [TBD]. Generation Capacity Resources that can achieve a Commercial Operation Date (COD) on or around June 1, 2015 will be favored in this solicitation.

2.3 PRODUCT QUANTITY

Respondents may offer Products in any quantity from Generation Capacity Resources not to exceed 1,800 MW on an installed capacity basis. The quantity of Capacity offered by a Respondent must be constant over the contract term.

The Commission may award one or more contracts to one or more Suppliers for Products derived from Generation Capacity Resources or may direct one or more EDCs to construct new generation up to, but not to exceed, a total installed capacity of 1,800 MW. The Commission reserves the right to reject all submissions to this RFP and reject the EDCs' proposals if in its sole discretion the Commission determines that Respondents' submissions or the EDCs' proposals are not in the public interest.

3 CONTRACT STRUCTURE

The Supplier will own and operate the Generation Capacity Resource committed in response to this RFP. The Supplier will remain responsible for O&M of the Generation Capacity Resource, including offering and scheduling the Generation Capacity Resource in PJM's DAM and/or RTM. In accordance with Section 3.2 (Payment), the Buyer will enter into a financial arrangement with the Supplier in which the physical delivery to the EDC of the Capacity, Energy and Ancillary Services is not required. Rather, the obligation of physical delivery and related performance of the Capacity, Energy and Ancillary Services, including the Offer Requirements in the Reliability Pricing Model (RPM) and the DAM and/or RTM will be an obligation of the Supplier to PJM in accordance with the PJM RAA, the PJM Operating Agreement and OATT. The financial arrangement between the Buyer and a Supplier for Capacity, Energy and Ancillary Services will be a Contract-for-Differences (CfD). Hence, the delivery of Capacity, Energy and Ancillary Services will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity, Energy and Ancillary Services. At Respondent's election, pricing for Capacity, Energy and Ancillary Services from Dispatchable Generation Capacity Resources may be offered on a cost-of-service basis, or, alternatively, based on a combination of a firm and indexed pricing basis, as described in Section 6.1, m. Pricing for Capacity, Energy and Ancillary Services from Non-Dispatchable Generation Capacity Resources shall not be offered on a cost-of-service basis but rather on a Fixed/Indexed price basis.

If the Products include RECs, the Buyer will pay the Supplier the contract price for RECs, and the Supplier will deliver RECs to the Buyer in accordance with the terms of the Agreements.

3.1 RESOURCE REQUIREMENTS

The Generation Capacity Resources provided must meet the following requirements:

a. The Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM capacity auction;

b. Capacity from the Generation Capacity Resources must meet all requirements to qualify for the BRA. The Supplier must offer the Capacity from the Generation Capacity Resource into the BRA for the Delivery Year that begins on the first

June 1 following the target Commercial Operation Date of the Generation Capacity Resource and into any Incremental Auctions for a Delivery Year that occurs after the Commercial Operation Date but prior to the June 1 following the target Commercial Operation Date of the Generation Capacity Resource(s.) The Supplier must offer such Capacity into the PJM BRA so that it will clear and be committed, subject to the direction and timely notification of the Commission;

c. The Supplier must keep separate in the PJM eRPM system the Generation Capacity Resources committed as a result of this RFP from other Generation Capacity Resources of the Supplier; and

d. The Supplier must provide the Buyer read-only access to its PJM eRPM system, Market Settlements Reporting System (MSRS), and Load Response system accounts for the Generation Capacity Resource(s) committed as a result of this RFP. Such accounts shall be used for the sole purpose of verifying contract performance.

3.2 PAYMENT

For the Supplier's Capacity and Energy, the financial arrangement between the EDC and the Supplier will be a CfD between a) the Supplier's contract Capacity price and the RPM LDA clearing price applicable to the Maryland EDC's service territory, and between b) the Supplier's contract Energy price and the hourly PJM nodal Locational Marginal Pricing (LMP) in the PJM DAM and/or RTM, as applicable, at the point of delivery into the EDC's service territory. If applicable, similar determinations of differences for Ancillary Services will be defined. If applicable, payments to Supplier for RECs will be based on the REC price set forth in the Agreements between the Supplier and the Buyer. ***For illustration purposes only***, a sample CfD transaction for Capacity, Energy, and Ancillary Services from a Dispatchable Generation Capacity Resource is shown in Attachment 1, Example 1. Example 2 in Attachment 1 illustrates a transaction for Capacity, Energy and RECs from a Non-Dispatchable Generation Capacity Resource. The schedule for billing net amounts of CfD obligations due to either party will be monthly.

3.3 NON-PERFORMANCE PENALTIES

Penalties for failure to provide proposed Products or to meet proposed heat rate and availability standards are defined in the Agreements (Attachments 9 and 10).

3.4 CREDIT REQUIREMENTS

All Respondents must provide financial information as described in Section 6.1 below. The Commission will determine if a Respondent and its Guarantors meet minimum standards of financial integrity.

General requirements for construction and operating phase security are described in Attachment 2. Specific preferred terms are presented in the Agreements (Attachments 9 and 10).

4 AGREEMENTS

Two model Agreements to be executed as a result of this RFP are provided as Attachment 9 (for cost-of-service pricing) and Attachment 10 (for Fixed/Indexed pricing). The Agreements contain the parties' rights and obligations for providing and receiving Capacity, Energy, Ancillary Services and, if applicable, RECs. While suggested changes to the model Agreements will be considered, offers which conform to all major terms will receive preference in evaluation.

5 ELIGIBILITY OF RESPONDENTS

5.1 ELIGIBILITY REQUIREMENTS

A Respondent is eligible to offer a proposal if, in a timely and complete fashion, the Respondent submits the following Eligibility Documents by the respective due dates indicated in Section 8:

a. A non-binding Expression of Interest Form, provided as Attachment 3;

b. An executed copy of the certification that the Generation Capacity Resource which the Respondent plans to commit under this RFP did not clear any prior PJM capacity auction, provided as Attachment 4;

c. An executed copy of the certification that the Respondent meets the PJM membership requirements, provided as Attachment 5;

d. An executed copy of the Binding Offer Agreement, provided as Attachment 6; and

e. An executed copy of the Confidentiality/Non-disclosure Agreement, provided as Attachment 11. A Respondent and the EDC issuing the RFP will be required to execute the Confidentiality/Non-disclosure Agreement. Once the agreement is received from the Respondent, the EDC will complete the execution of the agreement and send a copy of the fully executed agreement to the Respondent and to the Commission by mail, courier service, or appropriate electronic means.

5.2 AFFILIATE PARTICIPATION

An unregulated affiliate of an EDC may participate as a Respondent in this RFP process. The unregulated affiliate and its affiliated EDC will be subject to the provisions of the Code of Maryland Regulations, Title 20, Subtitle 40- Electric and Gas Companies-Affiliate Regulations.

6 PROPOSAL

6.1 PROPOSAL CONTENT

Proposal content must include:

a. Summary description of the Respondent, including:

- Name

- Legal form (*e.g.*, sole proprietorship, partnership, limited partnership, joint venture, corporation, etc.)
- Principal contact information (name, mailing address, telephone number, fax number, and email address)
- Date of establishment
- State of incorporation
- Residency of organization
- Organization chart of the Respondent's company showing parent company, subsidiaries, and affiliates
- If the Respondent proposes to have a Guarantor guarantee its obligations, then the above information also must be provided for that Guarantor
- If the Respondent is a joint venture or consortium, the above information must be provided for each member of the venture or consortium
- Description of technical and managerial experience and qualifications in the areas of permitting, development, financing, construction, and operation of electric generating facilities, including experience in the control of cost overruns
- Description of familiarity and experience with PJM markets and requirements for membership status with PJM
- Description of financial condition and evidence of creditworthiness, including senior unsecured long-term debt credit ratings from major rating agencies and the most recent two years' audited financial statements for Respondent and Guarantor, if applicable
- Description of other generation owned or under contract within the State of Maryland, including resources currently under development or construction
- Description of other principal team members, such as Engineering, Procurement, and Construction (EPC) and Operations and Maintenance Contractors, if any, and relevant experience of those entities
- Description of defaults, non-compliance, fraud or criminal misconduct by a Respondent or any of its officers, directors, partners, guarantors, or affiliates with any obligations relating to power or natural gas sales or purchases or transmission obligations
- Description of instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was the subject of an investigation or a proceeding relating to conversion, fraud, misrepresentation, false statements, unfair or deceptive business practices, business theft, anti-competitive acts or omissions or collusive offering or other procurement- or sale-related irregularities

- Description of any instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was convicted of any felony, or any crime relating to the sale of power, natural gas or transmission, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions or collusive offering or other procurement or sale-related irregularities

b. Summary description of the proposed Generation Capacity Resource, including:

- Description of site and surroundings, including description of site control (ownership, contractual arrangements, etc.)
- Map showing location of site and interconnection facilities
- Electric interconnection point with transmission system
- Interconnection status and cost estimates
- Copies of transmission interconnection studies conducted
- Nominal capacity
- Technology type
- Size of unit(s)
- Number of unit(s)
- Site plan drawing showing layout of major equipment and structures
- Description of Ancillary Services capability
- Commercial Operation Date and detailed critical path schedule, including timelines for permitting, engineering, procurement, construction, startup, and commercial operation
- PJM market participation eligibility
- Proposed contract term

c. Fuel Supply Plan / Energy Resource Assessment

- Fuel type and secondary fuel, if applicable
- Liquid fuel storage capacity on-site or contracted for, fuel replenishment rate, and oil tankage refill logistics
- Natural gas interconnection points, source of supply, interstate and local transportation arrangements
- Character of service on interstate pipelines, including definition of primary firm, secondary firm, and/or interruptible transportation rights with specific designation of receipt and delivery points on each pipeline segment on which Supplier has an entitlement

- Imbalance resolution arrangements with a gas utility, marketer or third party
- Identification of storage, Park & Loan, other arrangement providing for natural gas scheduling flexibility
- Other fuel supply and transportation arrangements (*e.g.*, supply plan for biomass fuel, landfill gas, or other if applicable)
- For Generation Capacity Resources using wind, solar, or other Non-Dispatchable sources of energy, a detailed assessment of the available resource, including expected P50 (50% probability estimate) annual seasonal and daily profiles, and upper and lower expectations, *e.g.*, P10, P90, (10% and 90% probability estimates) for annual energy potential

d. Permitting Plan

- List of any applicable federal, state, and local permits, certifications, and approvals required to construct and operate the Generation Capacity Resource and a projected timeline for securing any applicable federal, state and local permits
- Current status of all permits, certifications, and approvals required to construct and operate the Generation Capacity Resource including electric and gas interconnections
- Documentation of community support for Generation Capacity Resource

e. Capital Cost Estimate: If the proposed Generation Capacity Resource is offered on a cost-of-service basis, a detailed capital cost estimate must be provided. Additional detail must be provided in the form of a narrative supporting the scope of and level of confidence in the estimate.

f. Pass-Through Component: If the proposed Generation Capacity Resource is offered on a Fixed/Indexed basis, Respondents may offer certain components of capital costs on a "pass-through" basis from the Respondent if such costs can not be determined until after the completion of certain analyses, such as gas or electric interconnection studies. In this case, the estimated capital cost of the items to be passed through must be provided in detail, along with a description of all assumptions regarding scope, level of confidence and other factors.

g. Operating Cost Estimate: If the proposed Generation Capacity Resource is offered on a cost-of-service basis, a detailed operating cost estimate must be provided. The estimate should be summarized and narrative detail must be provided supporting the scope and level of confidence in the estimate.

h. Financing Plan: Description of plan and demonstration that the proposed Generation Capacity Resource can be financed. The sources of debt and equity investment must be provided. Anticipated usage of federal loan guarantees and/or production or investment tax credits available under federal programs must be identified, if applicable. Other sources of tax benefits attributable to accelerated depreciation benefits for specific Generation Capacity Resource technology types must be stated. The Financing Plan shall include a detailed *pro forma* cash flow statement showing the financial viability of the Generation Capacity Resource.

i. Ratepayer Benefits: Description of the reliability and economic benefits which are likely to be realized by Maryland ratepayers as a result of the Generation Capacity Resource.

j. State of Maryland Benefits: Description of other reliability, economic, socioeconomic and, if applicable, environmental benefits that are likely to be realized in Maryland as a result of the Generation Capacity Resource, *e.g.*, construction jobs, permanent employment during the operating period, tax effects, community improvements, other.

k. Contract: State any exceptions to the contract terms appearing in the Agreements (Attachments 9 and 10) or state that contract terms are acceptable in their entirety.

l. Detailed Operating Parameters

- For Dispatchable Generation Capacity Resources: Complete the worksheets appearing in Attachment 7 and provide any narrative that will facilitate the Commission's analysis of Generation Capacity Resource performance.
- For Non-Dispatchable Generation Capacity Resources: Complete the worksheets appearing in Attachment 8 and provide any narrative that will facilitate the Commission's assessment of Generation Capacity Resource performance. Specific information such as estimated monthly and hourly energy outputs from the project for a typical calendar year should be provided as well as a statement as to the certainty and probability of the energy projections. For solar projects, the manufacturer's guaranteed availability as well as climate shut-down constraints such as snow or ice storms should also be provided.
- The Commission reserves the right to seek additional information from Respondents to support its technical assessment of the Generation Capacity Resource submissions.

m. Pricing Proposal

- Respondents are invited to submit multiple pricing options for the same Generation Capacity Resource. Provide a narrative description of each separate pricing option offered with respect to the Generation Capacity Resource. The pricing option for each should include the total pricing provisions for the Capacity, Energy, Ancillary Services, and, if applicable, RECs produced by the Generation Capacity Resource over the contract term. Respondents are encouraged to provide pricing options that may also include contract extensions unilaterally exercisable by the Buyer. Principles for Fixed/Indexed pricing are described in detail in Exhibit G of Attachment 10 and on the pricing worksheets in Attachment 7 (Dispatchable Generation Capacity Resource) and Attachment 8 (Non-Dispatchable Generation Capacity Resource). Respondents offering a Dispatchable Generation Capacity Resource may choose to offer cost-of-service based pricing, as described in Exhibit E of Attachment 9. Pricing parameters under the cost-of-service option may only be provided in Attachment 7.

- Pricing may be specified for Capacity in either of the following forms:

1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:

    - A schedule of firm, fixed prices expressed as $/MW-day of Unforced Capacity ("UCAP") provided, for each Delivery Year (June 1 to May 31) of the contract term;
    - A fixed base price, expressed as $/MW-day of UCAP provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator;
    - A "pass-through" component, expressed as $/MW-day of UCAP provided, based on the actual capital cost of such items as electrical interconnection and natural gas interconnection costs, multiplied by a specified annual recovery factor and divided by a specified MW-day per year of UCAP.

2) A cost-of-service based Unit Annual Fixed Revenue Requirement, based on the principles defined in Exhibit E of Attachment 9 and applicable to Dispatchable Generation Capacity Resources only. A cost-of-service pricing proposal must include a proposed debt-to-equity ratio and a proposed return on equity (ROE), expressed as a basis point adder or deduction relative to the weighted average ROE authorized from time to time by the Commission for one or more Maryland EDCs that will enter into an Agreement pursuant hereto.

- Pricing for energy from a Non-Dispatchable Generation Capacity Resource must be specified as a combination of:

    - A schedule of firm, fixed prices expressed as $/MWh of energy delivered, for each Delivery Year (June 1 to May 31) of the contract term; and/or
    - A fixed base price, expressed as $/MWh of energy delivered, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.
    - The index-adjusted fixed base price multiplied by a table of price factors for on-peak and off-peak hours in the summer (June-September) and non-summer (October-May) months.

- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a Fixed/Indexed basis as described in Exhibit G of Attachment 10 shall consist of a heat rate call option with any or all of the following components:

1) A non-fuel variable component expressed as:
    - A schedule of firm, fixed prices expressed as $/MWh of energy delivered, for each Delivery Year (June 1 to May 31) of the contract term, and/or;
    - A fixed base price, expressed as $/MWh of energy delivered, and a formula for adjustment for each capacity Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.
2) A fuel component expressed as the product of:
    - a defined heat rate (MMBtu {Higher Heating Value (HHV)}/MWh) as a function of fuel, load, ambient temperature, and output degradation factor, and;
    - a fuel price ($/MMBtu) based on a published daily index plus defined adjustments for transportation and local delivery service adder(s), which is applied to energy output in each hour.
3) A start-up component consisting of:
    - A fixed base price, expressed as $/unit start, with a formula for adjustment for each capacity delivery year, based on a broad-based, published inflation index such as CPI or GDP deflator, and;
    - A fuel component defined as the product of a specified start-up fuel amount in MMBtu/unit start and a fuel price ($/MMBtu) based on a published daily index plus specified adjustments for transportation and delivery services.

- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a cost-of-service basis shall be priced in accordance with the provisions of Exhibit E of Attachment 9.
- If offered, a Black Start Service Price shall be specified as either:
    1) A Fixed/Indexed offer based on principles defined in Attachment 10, as a combination of:
        - A schedule of firm, fixed prices expressed as $/MW of Black Start Capacity provided, for each Delivery Year (June 1 to May 31) of the contract term;
        - A fixed base price, expressed as $/MW of Black Start Capacity provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator; or
    2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Black Start Service, based on the principles defined in Exhibit E of

Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.

- If offered, a Regulation Service Floor Price shall be specified as either:
  1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
     - A schedule of firm, fixed prices expressed as $/MW-hour of Regulation Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
     - A fixed base price, expressed as $/MW of Regulation Service provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator, and;
  2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Regulation Service, based on the principles defined in Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.
- If offered, a Synchronized Reserve Service Floor Price shall be specified as either:
  1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
     - A schedule of firm, fixed prices expressed as $/MW-hour of Synchronized Reserve Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
     - A fixed base price, expressed as $/MW of Synchronized Reserve Service provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator, or;
  2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Synchronized Reserve Service, based on the principles defined in Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.
- If offered, a Day-Ahead Scheduling Reserve Service Floor Price shall be specified as either:
  1) A Fixed/Indexed offer based on principles defined in Exhibit G of Attachment 10, as a combination of:
     - A schedule of firm, fixed prices expressed as $/MW-hour of Day-Ahead Scheduling Reserve Service provided, for each Delivery Year (June 1 to May 31) of the contract term;
     - A fixed base price, expressed as $/MW of Day-Ahead Scheduling Reserve Service provided, and a formula for

adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator; or

2) A cost-of-service based Unit Annual Fixed Revenue Requirement for Day-Ahead Scheduling Reserve Service, based on the principles defined in Exhibit E of Attachment 9 and applicable to Dispatchable Generation Capacity Resources only.

- If offered, REC prices may be fixed over the contract term or may include a formula for adjustment for each delivery year, based on a broad-based, published inflation index such as CPI or the GDP deflator, or indexation to energy prices in the PJM DAM.

6.2 Submittal of Proposals

Proposals from Respondents are due no later that 5:00 p.m. Eastern Prevailing Time (EPT), on September 15, 2011. Submit five (5) hard copies of the proposal through express mail (*e.g.*, FedEx, UPS, etc.) to the following name and address:

Name: Don Eveleth
Address: 6 St. Paul Street, 16th Floor, Baltimore, MD 21202
Phone: 410-767-8057
Fax: 410-333-3802

In addition to the hard copy submittal, submit electronic versions of the proposal to the following address:

develeth@psc.state.md.us

6.3 Proposal Confirmation

The Commission will confirm receipt of a Respondent's proposal by phone. As indicated in each proposal, the Respondent will provide a contact name and phone number which will be used for the receipt confirmation.

6.4 Expiration of Proposals

Proposals shall expire the earlier of the time Commission notifies the Respondent that its proposal has been rejected in full or part, or at midnight EPT on March 1, 2012. All Product pricing submissions must remain binding until midnight EPT on March 1, 2012.

6.5 Evaluation of Proposals

The Commission will evaluate the Generation Capacity Resource proposals and proposals from the EDCs to determine whether the proposals will enhance electric service reliability and are in the best interests of ratepayers. The Commission will evaluate all responsive proposals and proposals from the EDCs based on quantitative as well as qualitative evaluation criteria. After the proposals are submitted, the Commission may request additional information from Respondents or the EDCs in furtherance of the Commission's technical evaluation. A Respondent's failure to provide additional information on a timely basis may cause the Commission to reject such Respondent's proposal.

6.5.1 Minimum Threshold Criteria

In submitting proposals for the Commission's evaluation, Respondents must demonstrate that the proposed Generation Capacity Resource meets certain minimum threshold criteria related to the Respondent's managerial, technical, and financial capabilities. The minimum threshold criteria are those factors that are either explicitly mandated in this RFP or are otherwise deemed by the Commission to be integral to the successful development of the Generation Capacity Resource, in particular, the delivery of reliability and economic benefits for Maryland ratepayers. The minimum threshold criteria are designed to be straightforward factors that can be assessed by the Commission in an initial review of the proposals and therefore do not require extensive economic, commercial, or engineering analyses. Proposed Generation Capacity Resources that do not comply with each of the minimum threshold requirements will not be considered by the Commission for further evaluation.

The minimum threshold criteria are as follows:

1. The proposal includes all of the Eligibility Requirement documentation described in Section 5.1.
2. The Respondent possesses sufficient technical, managerial, and financial capability to implement the proposal in accordance with the Commission's requirements.
3. Proposals from an affiliate of a Maryland EDC must demonstrate that the Generation Capacity Resource will not receive any form of cross-subsidization by the EDC or other regulated affiliated entity.
4. Proponents must demonstrate a legal entitlement to each site on which a Generation Capacity Resource is proposed. Proof can be in the form of current ownership of the property, a current long-term lease on the property, or an option to lease or buy the property that can be exercised at any time until the Commission issues its final decision on the proposal and a contract is executed. Respondents must also demonstrate a legal entitlement to any required right-of-way to access electrical and fuel interconnection points.
5. The proposed Generation Capacity Resource must be interconnected to the System such that the Generation Capacity Resource's output may be infed to a node east of the Western Interface and deliverable to Maryland east of the Western Interface avoiding likely transmission congestion.
6. Respondents must provide proposals for building new Generation Capacity Resources. Existing generation capacity does not satisfy threshold procurement criteria set forth in this RFP. However, proposals for uprated capacity at existing

generation facilities or new units to be constructed at existing facilities will be considered in accord with the minimum threshold requirement set forth in this RFP, but only for the incremental capacity associated with the uprate or new unit at the existing facility. Any proposal for an uprate to an existing facility must include an explanation how the Products ascribable to the uprated capacity will be distinguishable from existing capacity.

7. Respondents must submit proposals that commit Generation Capacity Resources beginning no earlier than June 1, 2015 and no later than June 1, 2017.

8. Respondents or their guarantors must demonstrate a minimum investment grade credit rating, as defined in Attachment 2, if available. Absent an investment grade credit rating from Standard and Poor, Moody, or Fitch, comparable alternative credit support, including a Letter of Credit from a Qualified Institution as defined in Attachment 2 shall be provided.

9. While suggested changes to the model Agreements (Attachments 9 and/or 10) will be considered, offers which conform to all major terms will receive preference in evaluation.

6.5.2 Costs and Benefits to Ratepayers

Each proposed Generation Capacity Resource which meets the minimum threshold criteria will be evaluated with respect to the enhancement to reliability and the costs and benefits of the Products offered from the standpoint of Maryland's ratepayers.

For Generation Capacity Resources seeking cost of service pricing, Respondents must provide sufficient information to allow the Commission to conduct the requisite technical analysis to determine if the delineation of Generation Capacity Resource costs is reasonable. The Commission reserves the right to incorporate adjustments and modifications to account for missing or uncertain cost components. The Commission may seek clarification from Respondents regarding costs and technical operating parameters.

Respondents who propose Fixed/Indexed pricing must estimate costs for all pass-through items, *e.g.*, electric interconnection and transmission upgrade costs, natural gas interconnection costs to a pipeline or local distribution company, other facility improvements assignable to the Generation Capacity Resource, as well as "soft" costs including architectural, engineering, financing, and legal fees. The Commission may seek clarification from Respondents regarding such cost estimates. The Commission reserves the right to incorporate adjustments and modifications to pass-through cost data submitted by Respondents.

The Commission will evaluate the size and quality of the reliability enhancement and economic benefits associated with each proposal from Respondents and the EDCs that satisfies the minimum threshold criteria. Subject to the 1,800 MW limit available for long term contracts, the Commission also will consider the impact of different Generation Capacity Resource portfolios on the expected net benefits realized by the ratepayers of Maryland's EDCs.

6.5.3 QUALITATIVE FACTORS

Each proposal that meets the threshold criteria will also be subject to a qualitative evaluation based on an overall assessment of its merits. If the Commission determines that there is not a substantial difference in the costs to ratepayers of two or more proposals (including proposals from an EDC), the Commission will give proposals containing the following attributes (not necessarily listed in order of importance) more favorable consideration in determining which Generation Capacity Resources, if any, are in the best interest of ratepayers:

1. Early Commercial Operation Date (*i.e.*, on or around June 1, 2014) and low risk of project delays, certainty of achieving key project development milestones, including securing permits and interconnection agreements;
2. Low risk of cost increases to ratepayers resulting from factors such as electric transmission and fuel interconnection costs, payment in lieu of taxes (PILOT), and technical attributes of Generation Capacity Resource, cost of equipment and materials, etc.;
3. The Respondent's project development experience and managerial, technical, and financial capability in developing and operating generation projects;
4. Environmental benefits, including net reduction in emissions of air pollutants and greenhouse gases and reuse of existing generation or brown field sites;
5. Creation of construction and permanent jobs in Maryland.

The Commission will apply these criteria to all proposals that satisfy the minimum threshold criteria and include the analysis in the selection of a final award group, if any.

7 COMMUNICATIONS

This RFP, updates to this RFP, and other relevant information will be posted on the Maryland Public Service Commission's website at www.psc.state.md.us.

Questions regarding this RFP may be submitted to the Commission until the deadline indicated in Section 8. All questions regarding this RFP must be directed to:

Donald P. Eveleth

Deputy Executive Secretary

Maryland Public Service Commission

6 St. Paul Street, 16th Floor

Baltimore, Maryland 21202

The Commission will respond to questions as soon as practicable. Questions and responses will be posted on the Maryland Public Service Commission's website. Questions will be redacted as necessary to preserve the confidentiality of Respondents.

8 SCHEDULE FOR RFP PROCESS

In order to preserve a possible offering into the May, 2012 Base Residual Auction ("BRA") for the 2015-2016 delivery year, the RFP schedule is as follows:

Activity	Date
RFP issued	March 18, 2011
Solicitation for Expressions of Interest	April 8, 2011
Pre-offer conference	April 15, 2011
Eligibility Documents due	May 1, 2011
Issue Respondents' eligibility status	June 17, 2011
Deadline for receipt of Respondents' questions	July 1, 2011
Proposal Due Date	July 29, 2011
Staff/Consultant evaluation filed with Commission	December 2, 2011
Public comments due to Commission	December 30, 2011
Commission hearing	[TBD]
Commission selects and approves any winning offers	[TBD]
EDC(s) execute Commission-approved agreements	February 10, 2012
Advance notification of intent to offer due to PJM	March 1, 2012
Executed system impact study agreement in place	April 13, 2012

9 RESERVED RIGHTS

9.1 RESPONDENT ELIMINATION RIGHT

If, in the course of the RFP process, a Respondent is found to provide faulty information, misrepresent itself, or omit any pertinent information, the Commission reserves the right to eliminate such Respondent from the RFP process. The Commission also reserves the right to reject any proposal that does not comport with the requirements set forth in the RFP.

9.2 CONTRACT TERMINATION RIGHT

If a Respondent who engages in any conduct described in Section 9.1 (Respondent Elimination Right) is awarded an offer and executes the contract, the Commission reserves the right to terminate the contract and pursue remedies as outlined in the Agreements.

9.3 WITHDRAWAL AND REJECTION RIGHT

The Commission reserves the right to order the EDCs to withdraw, modify, or cancel this RFP at any time and the Commission may accept or reject any or all proposals received as a result of this RFP.

To the extent practicable, the Commission will inform Respondents that have filed an Expression of Interest form of any such change. The Commission further reserves the right to waive, in its sole discretion, any irregularity or defect in proposals received and to consider alternatives outside of this solicitation.

Nothing in this RFP limits the Commission's authority, and the Commission expressly reserves its authority to reject all submissions received under this RFP.

10 MISCELLANEOUS

10.1 WARRANTY ON INFORMATION

The information provided in the RFP has been prepared to assist Respondents in evaluating the RFP. It does not purport to contain all the information that may be relevant to a Respondent in satisfying its due diligence efforts. The Commission makes no representation or warranty, express or implied, as to the accuracy or completeness of the information in the RFP, and shall not be liable for any representation expressed or implied in the RFP or any omissions from the RFP, or any information provided to a Respondent by any other source.

Neither the RFP nor any other related correspondence from the Commission or its employees, agents, or consultants shall be considered legal, financial or other advice and does not establish a contract or any contractual obligations.

10.2 HOLD HARMLESS

Respondents shall hold the Commission and its employees, agents and consultants harmless of and from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a offer pursuant to this RFP.

Each Respondent is responsible for its costs incurred in responding to this RFP.

10.3 PROPOSALS BECOME COMMISSION PROPERTY

All proposals submitted by each Respondent pursuant to this RFP shall become the exclusive property of the Commission.

10.4 RESPONDENT'S ACCEPTANCE

The submission of a proposal to the Commission shall constitute a Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of this RFP and the Agreement(s) that are a result of this RFP.

The Respondent and its representatives irrevocably agree to submit to the personal jurisdiction of any State or Federal court located in the State of Maryland and any appellate court thereof in respect of any action, dispute or proceeding arising out of this RFP process, including but not limited to the execution, implementation and performance of an Agreement.

10.5 Permits, Licenses and Compliance with the Law

Respondent shall obtain all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to respond to this RFP. Subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

10.6 Regulatory Approvals

As indicated in Section 8 (Schedule for RFP Process) and as set out in the Agreements, the executed Agreements will be contingent upon the EDC's receipt of Commission approval. Respondent agrees to cooperate, to the fullest extent necessary, to obtain any and all required State, Federal or other regulatory approvals of the Agreement(s) resulting from its proposal(s).

10.7 Non-Discrimination Policy

Throughout the RFP evaluation, the Commission will not discriminate between, or grant preferences to, any Respondent based on race, gender, ethnic origin, creed or religion, in accordance with legal requirements. The Commission's consideration, evaluation and selection of proposals shall be entirely based on the merits of each proposal and not upon unrelated factors.