

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation )  
in Organized Wholesale Energy Markets ) Docket No. RM10-17-000

*COMMENTS OF THE  
NEW ENGLAND POWER GENERATORS ASSOCIATION*

The New England Power Generators Association Inc. (“NEPGA”) submits these comments on the Notice of Proposed Rulemaking the Commission issued regarding a potential uniform approach for compensating demand response resources in organized energy markets. *Demand Response Compensation in Organized Wholesale Energy Markets*, 130 FERC ¶ 61,213 (2010) (“NOPR”). As explained below, and in the attached affidavit from Dr. Roy Shanker (“Shanker Aff.,” attached hereto as NEPGA Exhibit 1), the Commission’s proposal suffers fundamental defects. With two carefully targeted, but critical, changes, however, the Commission’s proposal could improve the efficiency of organized markets—hence benefiting all stakeholders. We explain these targeted changes in detail below.

*INTRODUCTION*

NEPGA supports energy market demand response. So does sound economic reasoning. As far as we are aware, every economist who has ever given any substantial consideration to the issue of how to make energy markets work efficiently supports some form of demand response. Hence, our answer to the Commission’s question—“whether current compensation for demand response providers acting as a resource in the organized wholesale energy market[] is adequately procuring demand response” in the energy market (NOPR at P 20)—is no. Many potential energy market demand responders do not currently receive the right level of energy market compensation and hence, at least sometimes, either (a) will *not* respond when it *is* economically efficient for them to do so, or (b) *will* respond when it is *not* economically efficient for them to

do so. This is not, however, a situation where more is always better. Giving too small a price signal can result in economically inefficient—and thus wasteful—conduct. Conversely, giving too large a price signal results in equally, if differently, wasteful behavior. In Goldilocks fashion, only if the price is “just right”—or at least as close as practicable—will we see economically efficient levels of demand response.

The best way to solve this problem would be for all relevant state commissions to alter their retail ratemaking to ensure that all potential demand response providers “see” LMP as the price to which they can respond. But this obviously will take time to occur—if, in fact, it ever does. And given the division of jurisdiction over the electric industry between the states and the federal government, there obviously are limits to what the Commission can do to solve this problem.

One possibility, not explored in the NOPR, is for the Commission to rule, as it has in PJM, that entities capable of demand response, at least above a certain size threshold, can participate directly in the wholesale markets. *See Occidental Power Servs. v. PJM Interconnection*, 103 FERC ¶ 61,285, *reh’g denied*, 104 FERC ¶ 61,289 (2003). In fact, if it were possible for the Commission to mandate such participation, either directly or through aggregators, that would be the most effective step the Commission could take.

The Commission’s NOPR proposes another way to leapfrog over the jurisdictional divide that otherwise threatens efforts to achieve efficient levels of demand response. The Commission basically is proposing to let demand responders “see” LMP through redesigning RTO compensation for demand response, in addition to the compensation that exists at the retail level. In broad terms, this is a creative idea. But it will only work if the specific price signal is correctly calculated.

The NOPR proposes to pay LMP, with no adjustment, to demand response in any interval where that response occurs. The Commission thus rejected a proposal to pay LMP minus “G,” with G representing the generation component of the cost the demand responder pays for power at the retail level.<sup>1</sup> The Commission apparently considers its proposal comparable to the fact that generation is paid LMP for power delivered to the grid, without any “deduction” for the cost incurred to generate that power.

We wholeheartedly agree with the general proposition that demand response resources and generators should receive comparable payment for comparable products. Demand response resources and generators are not, however, comparable for all purposes. At least in New England, the two categories of resources face significantly different risks and obligations in the energy markets. They thus provide somewhat different products there. In addition, they each have different reliability implications—issues that arise mainly in the capacity market context. In fact, as we discuss below, the NOPR threatens to exacerbate already-serious comparability problems regarding the treatment of demand response resources and generation in the New England capacity markets.

If, however, we take the narrower focus used in the NOPR, we agree that demand response resources and generation are comparable tools, on the margin, to balance supply and demand in organized energy markets. Assuming appropriate effort is spent to harmonize, to the extent practicable, the risks and obligations the two types of resources assume in the energy markets, we agree with the goal of paying them comparable compensation in those markets.

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<sup>1</sup> See, e.g., *PJM Interconnection*, Docket No. EL09-68-000, Notice of Intervention, Comments, and Request for Settlement and Hearing, of the Indiana Utility Regulatory Commission at 1 (Sept. 16, 2009) (claiming that LMP-G “is an accepted indicator of cost-effectiveness”). Based on a recent presentation, we also expect NYISO to file comments today generally in agreement with the arguments herein. David Lawrence, New York Independent System Operator, *NYISO Response to FERC NOPR on Demand Response Compensation in Energy Markets 2* (2010) (“NYISO Presentation”), available at [http://www.nyiso.com/public/webdocs/committees/bic\\_prlwg/meeting\\_materials/2010-05-10/NOPR\\_on\\_DR\\_comp\\_MP\\_overview.pdf](http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2010-05-10/NOPR_on_DR_comp_MP_overview.pdf).

Putting these issues aside, the Commission’s proposal to pay LMP without any adjustment is facially wrong. By ignoring the existing retail price signal, it will get the wrong level of demand response (too much of it), and will create unjust, unreasonable and unduly discriminatory wholesale rates.

There is no need to deduct costs from the LMP payments made to generators, because generators actually incur those costs to deliver power. When they receive LMP, they earn the net amount equal to LMP minus their costs. Demand response providers, in contrast, would be paid, under the NOPR, to *not* do something—to *not* consume power. And in the normal course, the reward for not buying something is avoiding paying for what you do not buy.<sup>2</sup>

Ideally, as noted above, the retail price for power would be LMP, and demand response providers would earn LMP by avoiding paying it in retail rates. After all, everyone knows the truism, attributed to Benjamin Franklin, that “a penny saved is a penny earned.”<sup>3</sup> There is no economic difference between “saving” LMP by deciding not to pay it and “earning” LMP by being paid that price. Either way, you have LMP in your pocket—in one case by not removing it in the first place, and in the other case by placing it there anew.

The Commission is—or, at least, within the limits of its jurisdiction, should be—attempting to replicate that situation in the NOPR. And taking that perspective is the best way to

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<sup>2</sup> As one economist has wryly observed:

Normal markets allow consumers to sell what they do not consume as long as they own it, but no rational market pays consumers for not consuming what they do not own, even if they can prove that they would have bought it but didn’t. Paying somebody because they might have bought more but didn’t is as illogical, unfair, and inefficient as buying the Brooklyn Bridge from somebody who thought about buying it but decided to sell it instead.

Dr. Larry E. Ruff, Harvard Elec. Policy Group, *Economic Principles of Demand Response in Electricity* 4 (2002), [http://www.hks.harvard.edu/hepg/Papers/Ruff\\_economic\\_principles\\_demand\\_response\\_eei\\_10-02.pdf](http://www.hks.harvard.edu/hepg/Papers/Ruff_economic_principles_demand_response_eei_10-02.pdf).

<sup>3</sup> *Accord Abbeville Gen. Hosp. v. Ramsey*, 3 F.3d 797, 799 (5th Cir. 1993); *NLRB v. Gorbea, Perez & Morell, S. en C.*, 328 F.2d 679, 681 (1st Cir. 1964).

see the error of paying LMP, without adjustment, to demand response. Assume, for a moment, that a state commission has already gotten its retail rate design “right” for demand response purposes, and customers capable of demand response are paying LMP in retail rates for any incremental energy consumed. This means that these customers already earn LMP as compensation when they provide demand response, because they save paying LMP by not consuming. If these customers *also* are paid LMP by an RTO when they provide demand response, then they are double-dipping—they are getting LMP *twice*. That would over-compensate demand response, providing too powerful an incentive. The Commission thus would elicit the wrong amount of demand response while making wholesale rates unjust, unreasonable and unduly discriminatory.<sup>4</sup>

The correct outcome is for an end-user capable of demand response to be given a price signal at the RTO level equal to LMP minus what we will call “C” (this is our first recommended change to the NOPR). We define “C” as the marginal price that the consumer participating in a demand response program pays its load serving entity (“LSE”) for power at retail. If that amount is LMP, as in our prior example, then the “additional” price signal is zero (because LMP minus LMP equals zero). And that is exactly the right answer. If C is something less than LMP—which it typically would be in circumstances where demand response makes economic sense (and where retail rates do not yet “show” responders LMP)—then the correct answer is the amount by which LMP exceeds C.<sup>5</sup> The demand response provider earns C when it declines to consume power that it was entitled to buy from its LSE at the price of C. If an RTO then pays

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<sup>4</sup> See also NYISO Presentation at 7 (discussing possibility and problems of over-compensating demand response).

<sup>5</sup> See Prof. William W. Hogan, *Implications for Consumers of the NOPR’s Proposal to Pay the LMP for All Demand Response* (“Hogan Comments”), Attachment 1 to *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket No. RM10-17-000, Comments of the Electric Power Supply Association (May 12, 2010) (“EPSA Comments”).

LMP minus C, we “gross up” the total compensation for the demand response provider so that it equals LMP.<sup>6</sup> And once again, if we just pay LMP at the federal level, the compensation is too high: it will equal LMP *plus* C, which is the wrong answer.

One more component bears attention in this overview. The actual level of C will vary from case to case. And the best parties to identify the proper level of C are the demand response provider in question and its LSE, with appropriate input from state regulators. The NOPR is silent on how the cost of paying LMP (whether or not adjusted) will be allocated to load. We propose allocating the cost of paying LMP minus C directly to the LSE that serves the demand response provider at retail (our second recommended change to the NOPR). That appropriately incentivizes the LSE to ensure the right value of C. And it accomplishes this while holding the LSE harmless. Although the LSE will pay LMP minus C for every unit of demand response by the customer load it serves, it will also save exactly the same amount; it no longer will be buying that unit of power at LMP and then reselling it for the lower price of C.

As Dr. Shanker explains in detail in his affidavit, this structure properly tracks the underlying economics. In economic substance, the LSE is selling the end-use customer a call option—the right to call on power by paying a price of C. When LMP is higher than C, it may make sense for the demand response customer to stop consuming power and receive, instead, the market value of its call option, which would be LMP minus C (the value of the commodity minus the cost of executing the call at the agreed-upon strike price or retail rate).

In sum, if the Commission is going to create an additional price signal that seeks to supplement the compensation for demand response that already exists on the retail level—which

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<sup>6</sup> NYISO proposes two functionally very similar solutions: either having the demand responder paying retail price for the full baseline amount plus a payment for the amount of demand reduction at full LMP, NYISO Presentation at 9, or having the demand responder paying retail price for only the actual consumption plus for the amount of demand reduction at LMP reduced by the retail rate, *id.* at 10. Either will effectively result in a net payment to the demand responder of LMP minus C for the amount of demand reduction.

is the avoided cost of not paying retail rates—it has to take account of the specific retail rates that already exist in each instance. If it ignores this real-world factor, it will, by definition, get the wrong answer. And the result will be systematic overpayment for demand response—an unjust, unreasonable, and unduly discriminatory subsidy that violates the Federal Power Act.

### *ARGUMENT*

Under the NOPR, a section would be added to the Commission’s regulations:

Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must pay to those demand response providers, in all hours, the market price for energy for these reductions.

18 C.F.R. § 35.28(g)(1)(v) (as proposed in the NOPR). Unless altered as we set forth here, this proposal will create rates that (1) are unjust, unreasonable, unduly discriminatory and preferential; and (2) threaten to exceed the Commission’s jurisdiction, while, at the same time, effectively blocking states from fixing the demand response compensation problem at its source.

#### *I. THE DEMAND RESPONSE COMPENSATION PROPOSAL IS UNJUST, UNREASONABLE AND UNDULY DISCRIMINATORY*

One of the principal legal strictures on the Commission’s rate-making authority is to ensure that rates are not unduly discriminatory. The NOPR violates this obligation by paying demand response a higher net price in the energy markets than generation, although generation, if anything, is providing a higher-value product as the rules currently are constituted.

##### *A. The Right Demand Response Compensation Is LMP Minus C During Hours When LMP Is Higher Than C; Not LMP During All Hours*

We agree that at the margin in organized energy markets, demand response and generation can play interchangeable roles in balancing supply and demand. In that narrow sense they are comparable.

There also are, however, important differences. In particular, as we explain in the next section of these comments, there are significant differences in the respective risks and obligations that the current RTO rules, at least in New England, place on generation, on one hand, and demand response, on the other. Each type of resource thus provides a somewhat different product. The Commission should work on narrowing this gap as part of its rulemaking effort, requiring each RTO to propose appropriate changes to its existing tariff structure.

In addition, there are important differences in the reliability “value” provided by demand response and generation. It would be impossible, for example, to run the bulk power system solely on demand response. In our view, however, these issues, and the associated comparability concerns, primarily arise in the capacity market context, at least in New England. If the Commission is going to unilaterally impose a new scheme of “comparable” demand response compensation through the ISO-NE energy markets, it should at the same time remedy the comparability problems in the FCM design, particularly where imposing a new scheme of demand response energy market compensation will exacerbate problems in the FCM design.

Assuming these issues are appropriately resolved, the Commission should set RTO compensation for demand response so that total compensation for demand response at both the wholesale and retail level equals LMP. The presence of incremental demand response and incremental supply each can affect LMP in different ways. Backing off demand generally will reduce LMP from what it otherwise would be, while dispatching incremental supply generally will increase LMP from what it otherwise would be. Both types of resources should receive total compensation equaling LMP.

We strongly disagree, however, with the NOPR’s specific compensation proposal, which is for RTOs to pay LMP, with no adjustment, to demand response. Because any RTO demand

response compensation is *on top of*, rather than *instead of*, existing retail rate compensation for reducing demand, the right answer is to pay, at the federal level, LMP minus C. This produces total demand response compensation exactly equal to LMP (LMP minus C from the RTO, plus C from avoiding purchases at retail rates). In contrast, the NOPR would result in overcompensation—LMP *plus* C (LMP from the RTO, plus C from the foregone retail purchase).

This is the error in Professor Kahn’s contention. He states that “[t]he (incremental) costs saved by curtailments in demand clearly will be full LMP—including the marginal costs of generation. So, in the end, full LMP inducement is the economically correct one.”<sup>7</sup> We agree that “full LMP inducement is the economically correct one.” Kahn Aff. at 3. But ordering RTOs to pay full LMP, without adjustment, to demand response does not achieve that goal because it ignores the existing “inducement” at the retail level—the savings from not paying the applicable retail rate. Reducing consumption by one unit already saves the consumer the retail charge, of C, that it otherwise would have paid to the LSE. Adding an additional payment of LMP minus C will create a total price signal of LMP (LMP, plus C, then minus C), which Professor Kahn and, implicitly, the NOPR recognize is the economically correct one. Adding the full LMP, as proposed by the NOPR, on top of the consumer savings of C, would create a total price signal of C *plus* LMP, which is *not* the economically or legally correct one.

It has been argued, in contrast to our position, that a demand responder does not *actually receive* a payment of C from its LSE for each unit it declines to consume; rather it merely *saves* itself a payment of C to its LSE.<sup>8</sup> This is economically nonsensical. As noted above, a penny (or,

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<sup>7</sup> Affidavit of Alfred E. Kahn at 3 (“Kahn Aff.”), Attachment A to *PJM Interconnection*, Docket No. EL09-68-000, Comments and Protest of Demand Response Supporters (Sept. 16, 2009).

<sup>8</sup> *Cf.*, e.g., Donald J. Sipe, *Demand Response Compensation (A Reality-Based Approach)* 10-11 (“Sipe Comments”), Attachment A to *PJM Interconnection*, Docket No. EL09-68-000, Motion for Leave to File Comments Out of Time and Comments of The American Forest & Paper Association and White Paper (Dec. 14, 2009).

we might say, C) saved is a penny (or C) earned. *See supra* note 3. Dr. Shanker explains this point at length.<sup>9</sup>

It is instructive to analogize compensation for virtual supply. Virtual supply effectively buys power in the day-ahead market and then sells that same power in the real-time market to arbitrage the two. And the compensation paid for virtual supply is the difference between day-ahead and real-time power prices. The approach proposed in the NOPR is equivalent to paying virtual supply the real-time LMP without deducting the day-ahead market price—effectively giving energy to the market participant for free and allowing it to sell that energy back to the RTO at LMP. And that is effectively what the NOPR does.

Our approach also is consistent with the Commission’s prior pronouncements about compensating demand response in the energy markets. As the Commission explained in addressing demand response compensation in PJM:

The financial benefit is comprised of two components: (i) the retail rate that is avoided by not consuming, and (ii) the payment received under the program, which is equal to the difference between the LMP and the retail rate. For example, if the LMP is \$600/MWh and the retail rate is \$50/MWh, the customer who reduced consumption would avoid the \$50/MWh retail charge and would receive a payment under the program of \$550/MWh (i.e., \$600-\$50), for a total financial benefit of \$600/MWh, which is the value of the LMP. But with the subsidy payment, the financial benefit for reducing consumption would exceed the LMP. That is, with the subsidy payment, the customer would receive a payment of \$600/MWh (i.e., the LMP) and in addition would avoid the \$50/MWh retail rate, for a total financial benefit of \$650.

*PJM Industrial Customer Coalition v. PJM Interconnection*, 121 FERC ¶ 61,315 at n.19 (2007); *see also PJM Interconnection*, 99 FERC ¶ 61,227 at 61,941 (2002) (“PJM should compensate the customer by paying the difference between the LMP and what the customer would save by not

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<sup>9</sup> Under an ideal retail rate tariff, the consumer would already pay a marginal price of LMP for the power it consumes and this discussion would be unnecessary. *See Shanker Aff.* ¶¶ 7-12. Having a direct payment of C to the utility, topped off by a subsidy for reduction of *LMP-C* is a second best solution required by jurisdictional limitations. *See Shanker Aff.* ¶¶ 6, 43.

using power (the retail price it didn't have to pay)."). The Commission has failed to explain its sharp departure from this prior—and eminently correct—reasoning.

In addition, our proposal creates the right incentives for retail consumers. If, as the NOPR proposes, demand response is compensated at a total price of LMP plus C, productive activities that potential consumers would undertake at the correct price of LMP will no longer be undertaken. If, as we propose, total compensation for demand response equals LMP, then demand response will occur exactly when it should—when it is more efficient to save, by not consuming, than to buy and consume. Under the NOPR, wasteful demand response incentives will exist in virtually all situations; under our proposal, the incentives will be properly aligned. Shanker Aff. ¶ 4.

Furthermore, unlike the NOPR's proposal, our proposal can be fully funded from its beneficiaries. Under our proposal, every unit of demand response receives demand response compensation of LMP minus C. But at the same time, every unit of demand response saves the demand responder's LSE from having to buy that unit at a wholesale rate of LMP and resell it at C, making a loss on each unit of LMP minus C. Hence, the RTO can fully fund demand response by charging the LSE the same amount that the LSE saves by virtue of demand response, holding the LSE harmless on a net basis. In contrast, the NOPR cannot be fully funded out of the LSE's savings from demand response, because it would bestow an additional subsidy. There thus is a "missing money" problem with the NOPR's approach.<sup>10</sup> While the NOPR does not specify where the extra funds would come from, they would have to come from someone, and they are likely to be significant. There is, we submit, no rational or lawful basis for creating this type of subsidy and requiring other market participants to pay for it.

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<sup>10</sup> See also NYISO Presentation at 4-5 (recognizing same problem with NOPR).

*B. It Is Unduly Discriminatory for RTOs to Pay Demand Resources LMP, Rather Than LMP Minus C, for Energy*

The NOPR states that “a reduction in consumption is comparable to an increase in electricity production for purposes of balancing supply and demand.” NOPR at P 20. As explained above, we agree with this specific, narrow point: a reduction in consumption and an equal-size increase in production have the same effect on balancing supply and demand. Hence, at the margin in the energy markets, they are functionally equivalent. *See* Shanker Aff. ¶ 1 n.3.

If we assume *arguendo* from this that demand response and generation are fully comparable in the energy markets, it follows that they should get equivalent compensation in those markets. And as we explain above, paying demand response providers full LMP, without adjustment, would give them substantially greater overall compensation than generators receive. As set forth in the prior section, demand response should receive the same *net price* as generation. For demand response to receive the same total price, it only needs to be topped off by LMP minus C. The NOPR therefore unduly discriminates between products, while, at the same time, contending that they are equivalent. This is, on its face, undue discrimination that violates the Federal Power Act.

In reality, demand response and generation, viewed broadly, are not fully comparable in the energy markets. As noted above, the RTO rules, at least in New England, impose substantially greater risks and obligations on generation than on demand response providers. For example, under the existing ISO-NE Day-Ahead Load Response Program, demand response providers may offer a very small quantity into the ISO-NE day-ahead energy markets in order to obtain the ability to sell a much larger quantity in the real-time energy market. By this strategy, they can avoid real-time deviation uplift charges, unlike generation suppliers, which must offer, into the day-ahead market, all megawatts that have cleared in the capacity market, with more

substantial exposure to uplift. ISO-NE Tariff § III.13.6, III.E.2 . And in this situation, unlike generation resources, the demand response provider is *not* required to update the RTO/ISO throughout the day with its status and ability to curtail the additional increment of demand response offered into the real-time market (but not the day-ahead market). *Id.* Demand response providers also are not subject to the same metering or asset registration requirements as generation resources. ISO-NE Tariff § III.E.6 (and ISO-NE manuals LRP and MVDR referred to therein). This complicates efforts to verify the amount of demand response that actually has been provided.

Given these significant differences (and others, in addition to these), there is no rational or lawful basis for demand response to receive a *higher* level of total compensation than generation, particularly for assuming a *lower* level of obligations to the system. If anything, generation should be paid more. It would, however, be acceptable, from our perspective, for the Commission to modify its proposed compensation scheme to pay LMP minus C, and to allocate the resulting RTO costs to the relevant LSE, while directing RTOs to make appropriate changes in their energy market rules to minimize, to the extent practicable, the disparate levels of risk and obligation that those rules impose on generation and demand response in the energy markets. While the energy market rules need not be identical, where there are material differences in treatment that are not justified by differences in technology, those differences should be removed.

*C. Paying LMP Without Adjustment in the Organized Energy Markets Would Magnify Existing Unduly Discriminatory and Preferential Treatment for Demand Response in the New England Capacity Markets*

As also noted above, there are important differences between demand response resources and generation when it comes to maintaining the reliability of the system. These differences are particularly important in reliability planning. Hence, by focusing solely on the organized energy markets, the NOPR is looking at only part of the picture. There are significant comparability

issues in the New England capacity market context. In fact, demand response receives greater FCM compensation than generation, although it is, we submit, beyond dispute that generation provides more reliability support to the system than demand response—particularly where there is no way to enforce actual reductions in real time. And the NOPR will exacerbate this already unjust, unreasonable and unduly discriminatory situation.

For example, in the FCM design, capacity payments to generation resources are reduced by net energy revenues—the Peak-Energy Rent (“PER”)—above certain threshold levels. ISO-NE Tariff § III.13.7.2.7.1.1 (“Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations ... shall be decreased by Peak Energy Rents.”). The underlying reasoning is that energy markets that clear at high levels already include scarcity rents that are economically akin to capacity payments. By reducing capacity payments to reflect these scarcity rents in the energy markets, it is thought that the markets avoid double-paying for capacity.

Capacity payments to demand resources are, however, *exempt* from the PER reduction. *Id.* If demand resources received no energy market payments (and hence no PERs either), and the associated end-use customer load were required to rely on its own interruptions in positive PER hours, and not share in the PER distributions from the aggregate of capacity purchases made from non-demand response supply, such an exemption might be justified. But demand resources currently receive energy market payments under ISO-NE’s existing Day-Ahead Load Response Program; they also would under our proposal here, and under the NOPR’s. If demand response resources continue to receive energy market payments, or if they benefit from PER distributions from capacity purchased on behalf of other loads, then there is no justification for

exempting them from the PER reduction.<sup>11</sup> If it is appropriate to impose a PER reduction on capacity payments to other resources, it is appropriate to do the same for capacity payments to demand response resources. Notably, this is the end result reached by the capacity market designs in both PJM and New York. *See Shanker Aff.* ¶ 50.<sup>12</sup>

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Given these considerations, if the Commission proceeds with a generic requirement regarding demand response compensation in the energy markets, it should require each RTO to make other appropriate changes in any market where there is a lack of comparability in the treatment of demand response resources and generation. The Commission has the statutory duty to ensure that RTO rules are not unduly discriminatory. It should discharge that obligation fully here.

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<sup>11</sup> Under current FCM rules, a demand resource load paid as capacity supply receives the portion of the capacity payments attributed to valuation of Peak Energy Rents, has no PER deduction applied and therefore provides no PER hedge to other capacity buyers. Yet that demand resource load enjoys the PER distributions (peak energy rent hedge) required of all other forms of capacity purchased on behalf of other loads. This requires other loads to pay for the PER hedge the end customer receives, while those loads get nothing in return. This design actually creates a disincentive for the end-use customer to respond in the energy market in high LMP hours other than FCM performance hours. That is, the demand resource load receives payment (through the FCM clearing price) as if providing a peak energy hedge to other loads (returning that portion of the FCM payments), without actually doing so or needing to respond in those energy market hours. While the absence of interruption in FCM Performance Hours would result in loss of the FCM payments, there is no FCM consequence on demand resources for not interrupting in positive PER hours where no operating reserve depletion is forecasted day ahead or occurs in real time. They get the share of PER distributions paid by other loads whether they reduce load or not. *See ISO New England*, Docket No. ER10-787-000, Motion to Intervene and Protest of GDF SUEZ Energy Marketing NA, at 6-8 (Mar. 15, 2010).

<sup>12</sup> A second, related example concerns peak-load-share ratios. The FCM allocates charges for capacity among LSEs on the basis of their ratio of peak-load share. ISO-NE Tariff § III.8.9. Under the FCM, this peak load currently is not adjusted by amounts of coincident peak load reduction that is credited to demand response and paid as capacity through the FCM. This provides an additional level of overcompensation. In the normal course, capacity markets would compensate demand response by reducing the relevant LSE's share of peak load, thus reducing its capacity obligation. If, as capacity markets currently provide, we are going to compensate demand response providers as capacity suppliers, then we need to add the actual reduction in coincident peak hour demand back into the peak load data used to calculate capacity cost obligations. Otherwise we once again double-dip compensation to demand response resources. While other markets, such as PJM, may have fixed this problem, New England has not. This is unduly discriminatory and contrary to the Federal Power Act.

II. *THE COMMISSION SHOULD CLARIFY THE BASIS FOR ITS JURISDICTION, AND ADJUST ITS DEMAND RESPONSE COMPENSATION PROPOSAL TO AVOID UNDERCUTTING STATE AUTHORITY OVER DEMAND RESPONSE, WHICH IS, BY ANY MEASURE, MORE COMPREHENSIVE THAN THE COMMISSION'S*

A. *Congressional Policy Did Not Create Jurisdiction for the NOPR*

We respectfully request that the Commission clarify the basis for its jurisdiction to act as proposed in the NOPR. The NOPR relied on a congressional statement of policy “encourag[ing]” demand response programs under the Energy Policy Act of 2005 (“EPAAct 2005”). Specifically, Section 1252(f) of EPAAct of 2005 provides that:

*It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.*

EPAAct 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594, 965 (2005); *see also* NOPR at P 5 n. 17 (quoting emphasized language).

Subsequently, in *EnergyConnect*, 130 FERC ¶ 61,031 (2010), the Commission stated that it no longer would view transactions providing demand response as “wholesale sales that ‘involve the sale for resale of energy that would ordinarily be consumed’ by an end-use consumer,” *Id.* at P 31. In fact, there the Commission expressly disclaimed any direct jurisdiction over demand response. *Id.* at P 30.

Given these two pronouncements, the NOPR appears to rest, for jurisdictional purposes, on a congressional statement of policy. Only 19 days after the issuance of the NOPR, however, the D.C. Circuit rejected an exactly parallel argument by the FCC. In *Comcast Corp. v. FCC*, No. 08-1291, slip op. (D.C. Cir. Apr. 6, 2010), available at <http://pacer.cadc.uscourts.gov/common/opinions/201004/08-1291-1238302.pdf>, the court unanimously dismissed the argument

that a statement of congressional policy gives an agency jurisdiction to undertake any ancillary measure to support that policy. In that case, the FCC relied principally on a congressional statement that it “is the policy of the United States ... to promote the continued development of the Internet and other interactive computer services” and “to encourage the development of technologies which maximize user control over what information is received by individuals, families, and schools who use the Internet.” *Id.* at 17 (quoting 47 U.S.C. § 230). The FCC contended that because “Comcast’s network management practices frustrated both objectives,” it came within its “statutorily mandated responsibilities” and hence it had jurisdiction to regulate these practices. *Id.* at 17, 18.

The court, however, decisively rejected these arguments:

The teaching of [precedent]—that policy statements alone cannot provide the basis for the Commission’s exercise of ancillary authority—derives from the axiomatic principle that administrative agencies may act only pursuant to authority delegated to them by Congress. Policy statements are just that—statements of policy. They are not delegations of regulatory authority.

*Id.* at 22 (internal citations, alterations, and quotation marks omitted). Hence, while “statements of congressional policy can help delineate the contours of statutory authority” granted elsewhere, statements of policy cannot substitute for grants of authority. *Id.*

Given this, we respectfully request that the Commission clarify the basis for its jurisdiction to enact the NOPR. The Commission has, elsewhere, set forth additional jurisdictional reasoning regarding demand response programs in RTOs. The record developed in this rulemaking would benefit from clarity on this point.

*B. Unless Changed as We Propose, The NOPR Will Interfere With and Frustrate State Retail Ratemaking Policy*

As the NOPR recognizes, there is wide variation in state demand response policy:

[T]he levels of compensation for demand response vary significantly among RTOs and ISOs. PJM pays the Locational Marginal Price (LMP) minus the

generation and transmission portions of the retail. The Midwest ISO currently has a program that pays LMP for demand response in the real-time energy market when the demand response provider has purchased the amount reduced in the day-ahead market for energy and ancillary services. CAISO pays LMP in its participating load program that allows qualifying resources to provide day-ahead and real-time energy and non-spinning reserves rate. ISO-NE and NYISO currently pay LMP when prices are above a threshold level, with the levels differing between the RTOs. SPP currently has no demand response program at all.

NOPR at P 8 (internal citations omitted). The NOPR also recognizes that even this geographic variation is not stable, but can be expected to change from market to market and day to day.

NOPR at P 3 n.8. Hence it is not surprising that the NOPR sought “comment on whether requiring payment of LMP is appropriate across all ISOs and RTOs, or whether variations among ISOs and RTOs justify varying levels of demand response resource compensation.”

NOPR at P 20; *see also* NYISO Presentation at 11 (noting that proper compensation for demand response in the energy market must reflect the differences in design of the different markets).

The NOPR fails, however, to address a second source of relevant geographic variability: states, LSEs, and retail rate classes. This creates a wide diversity of incentives for end-use consumers—the individuals who are going to make demand response decisions—a spectrum vastly larger than the variation among organized markets. The NOPR erroneously ignores the reality of these many different existing retail price signals. Our proposal, by properly taking into account retail rates, bridges this gulf.

Consider, for example, a consumer who, under a well-designed existing retail rate plan, already pays a marginal rate of LMP for power and adjusts its usage accordingly. There appears to be near-universal agreement that this type of rate design creates just the right incentives for

efficient demand response without any need for further Commission action.<sup>13</sup> The consumer sees the right price directly through its retail arrangement with its LSE.<sup>14</sup>

Now imagine the NOPR's solution imposed on top of what would otherwise be the ideal retail-rate solution. Suddenly the consumer no longer sees the correct price of power—which is LMP—but effectively earns twice LMP when it reduces demand—once in reduced retail power bills and once again as a demand response resource under the NOPR. And because demand response is particularly important during wholesale price spikes, the difference between (1) the correct incentive (LMP) and (2) the incentive the NOPR wrongly would provide (twice LMP) could be very large indeed.

In short, whenever state commissions, LSEs and consumers adopt what indisputably is the most efficient retail rate design for achieving demand response, the approach proposed in the NOPR would, if adopted, ruin that effort. The excessive price signal the NOPR envisions would drown out any state effort to give the right price signal.

This is not, we respectfully submit, the right role for federal regulation here. If the Commission is going to seek to bridge the gap to create efficient price signals for demand

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<sup>13</sup> Cf. *PJM Industrial Customer Coalition v. PJM Interconnection*, 121 FERC ¶61,315 at n.19 (2007); See generally *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket RM10-17-000, Comments of Charles J. Cicchetti, Ph.D. (Apr. 27, 2010); Ruff, *supra* note 2; Monitoring Analytics, LLC, *Barriers to Demand Side Response in PJM* (2009), [http://www.monitoringanalytics.com/reports/Reports/2009/Barriers\\_to\\_Demand\\_Side\\_Response\\_in\\_PJM\\_20090701.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/Barriers_to_Demand_Side_Response_in_PJM_20090701.pdf); Monitoring Analytics, LLC, *PJM Regulation Market: Impact of December 1, 2008 Changes in Market Design, December 1, 2008 – October 31, 2009* (2009), [http://www.monitoringanalytics.com/reports/Reports/2009/IMM\\_PJM\\_Regulation\\_Market\\_Impact\\_20081201\\_Changes\\_20091130.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf); Prof. William W. Hogan, *Providing Incentives for Efficient Demand Response*, Attachment A to *PJM Interconnection*, Docket No. EL09-68-000, Motion for Leave to Answer and Answer of the Electric Power Supply Association (Oct. 30, 2009); Hogan Comments; Hung-po Chao, *Price-Responsive Demand Management for a Smart Grid World*, 23 *Electricity J.* 7 (2010); NYISO Presentation; *PJM Interconnection*, Docket No. EL09-68, Motion to Intervene and Protest of Robert J. Borlick Opposing PJM's Proposed Tariff Changes (Sept. 16, 2009); *PJM Interconnection*, Docket No. EL09-68, Robert L. Borlick's Response to the Demand Response Supporters' Witnesses (Sept. 28, 2009); Affidavit of Jeffrey Tranen, Attachment A to the *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket No. RM10-17-000, Comments of the PJM Power Providers Group (May 12, 2010); but see Sipe Comments at 10 (mocking the idea of efficient pricing at LMP).

<sup>14</sup> The universal adoption of such retail pricing schemes, while outside the Commission's jurisdiction, is the principal, first-best policy proposal of Dr. Shanker. Shanker Aff. ¶¶ 7-12, 41-43; see also NYISO Presentation at 8.

response, it should do so in a way that allows state initiatives room to grow in a constructive direction. Our proposal does that. The NOPR's does not.

*CONCLUSION*

For the foregoing reasons, NEPGA<sup>15</sup> urges the Commission to reconsider the NOPR and replace it with the alternative rules set forth herein.

Respectfully submitted,

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May 13, 2010

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<sup>15</sup> NEPGA is a private, non-profit entity that advocates for the business interests of non-utility electric power generators in New England. NEPGA's member companies represent approximately 28,000 megawatts of electrical generating capacity throughout the New England region. NEPGA's mission is to promote sound energy policies which will further economic development, jobs, and balanced environmental policy. NEPGA's member companies are responsible for generating and supplying electric power for sale within the New England bulk power system. These comments represent the position of the organization as a whole, but not necessarily the position of any particular member with respect to any statement, concept, issue or position expressed herein.

\* NEPGA requests that all further correspondence, communications and other documents relating to these dockets be served upon these individuals electronically at [aoconnor@nepga.org](mailto:aoconnor@nepga.org) and [Paul.Wight@skadden.com](mailto:Paul.Wight@skadden.com).

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation )  
in Organized Wholesale Energy Markets ) Docket No. RM10-17-000

*AFFIDAVIT OF ROY J. SHANKER PH.D.  
REGARDING THE ENERGY MARKET DEMAND RESPONSE NOPR  
ON BEHALF OF THE NEW ENGLAND POWER GENERATORS ASSOCIATION*

1 I. INTRODUCTION

- 2 1) My name is Roy J. Shanker.<sup>1</sup> I have been asked by the New England Power Generators  
3 Association (“NEPGA”)<sup>2</sup> to review and comment upon the inquiries posed by the  
4 Commission in its March 18, 2010 Notice of Proposed Rulemaking, Demand Response  
5 Compensation In Organized Wholesale Energy Markets (RM10-17-000), 130 FERC  
6 ¶ 61,213 (2010) (“NOPR”). Specifically I was asked to focus my review on the  
7 incremental costs to provide an additional unit of energy at any location and time, and the  
8 appropriate incentives that should be presented to any potential consumer of electric power  
9 at the same location and time with respect to a reduction of their demand from what it  
10 would have been.<sup>3</sup>
- 11 2) The Commission proposes to require organized markets to pay all demand response the  
12 locational marginal price (“LMP”) in all hours for such reductions. In support, the

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<sup>1</sup> I have extensive experience spanning 37 years in the electric utility industry and have been an active participant in the development of formal organized wholesale markets since 1995. In all of these markets the issues related to the design and compensation for participation in demand response programs has been a continuing activity in the stakeholder process in which I have been an active participant. A summary of my experience is attached as NEPGA Exhibit 2.

<sup>2</sup> NEPGA is a private, non-profit entity that advocates for the business interests of non-utility electric power generators in New England. NEPGA’s member companies represent approximately 28,000 megawatts of electrical generating capacity throughout the New England region.

<sup>3</sup> I base my conclusions on the simplifying assumption that the relevant tariff would ensure comparability between generation and demand response in all other regards, including capacity markets, and then consider the appropriate response to the Commission’s questions regarding proper payments in energy markets within that context. However, if a particular tariff grants preferential treatment to demand response or other demand-sponsored measures over generation in other aspects, as I have recently testified ISO-NE’s Forward Capacity Market does in some important regards, *see* Affidavit of Roy J. Shanker Ph.D., NEPGA Exhibit 1 to *ISO New England Inc.*, Docket No. ER10-787-000, Motion to Intervene and Protest of the New England Power Generators Association (Mar. 15, 2010) and Supplementary Affidavit of Roy J. Shanker Ph.D., NEPGA Supplementary Exhibit 1 to *New England Power Generators Assoc. Inc. v. ISO New England Inc.*, Docket Nos. EL10-50-000 and ER10-787-000, Motion for Leave to Answer and Answer of the New England Power Generators Association (Apr. 13, 2010), my conclusion with respect to the energy market could change: The “right” pricing I am proposing for energy is predicated on parity in all other respects. Certainly granting preferential treatment to demand response in the energy market, as the NOPR proposes, *in addition to* preferential treatment in the capacity markets, would typically be even more inefficient than doing so in one market only. *See also* Comments of NEPGA, filed herewith, at 13 (noting that ISO-NE’s tariff “impose[s] substantially greater risks and obligations on generation than on demand response providers” even in the energy markets).

1 Commission correctly notes that LMP is the incremental direct cost of production of energy  
2 in the wholesale bulk electric market to serve one more unit of electric energy in any  
3 location at any given time. The Commission then incorrectly extrapolates from this that all  
4 demand response should be paid the full LMP in all hours. This conclusion does not  
5 follow. It ignores the particular circumstances (particularly their retail rate  
6 obligations/arrangements) of any given customer. It simply assumes that any decrement of  
7 use of a unit of energy by a customer will be entitled to uniform compensation for such  
8 “conservation or demand response” at a value set at 100% of the associated LMP. In  
9 particular the policy is blind to the realities of the differences between wholesale price  
10 structures, and the actual pricing and business relationships between the wholesale  
11 purchaser (load serving entity or LSE) and the retail consumer. In turn, the Commission’s  
12 proposal ignores the economic incentives or disincentives created by the combination of a  
13 potential reduction in wholesale production and payments combined with a change in retail  
14 consumption and rate payments.

- 15 3) Because of this, the Commission’s proposed policy is incorrect. Even if we assume, as I  
16 was instructed, that appropriate product definitions or limitations are in effect to assure  
17 comparability with respect to reliability and adequacy, the Commission’s proposed policy  
18 ignores the fundamentals of markets in general, and many of the details of the organized  
19 wholesale markets in particular, and mischaracterizes the consumer’s decision-making  
20 process about when to consume energy. As a result, the Commission’s proposal, rather  
21 than setting the right incentives for demand response, will create a material, grossly  
22 inefficient subsidy for wasteful conduct.

1 4) To be clear, I fully support a market design that sends the right signals to get the right  
2 amount of demand response. However, the approach outlined in the NOPR will not  
3 accomplish that objective. In my view, the proposal in the NOPR would simply create a  
4 very large and unwarranted subsidy (and associated tax) that is unnecessary and  
5 counterproductive. There are better (and simpler) steps to take to elicit the correct amount  
6 of demand response without creating subsidies and price discriminating against existing  
7 resources. *First*, the Commission should take all actions within its jurisdictional control to  
8 ensure that consumers see actual dynamic LMP pricing. *Second*, a temporary program  
9 based on a call option type structure replicating the relationship between LSE's and retail  
10 customers (as in PJM) could be implemented, but the payment to demand response  
11 providers should be LMP-C (where C is the marginal price of power actually paid by the  
12 retail consumer),<sup>4</sup> not full LMP. Such a payment would be made from the LSE to its retail  
13 customer based on the agreed level of demand response.<sup>5</sup> Otherwise, there is a substantial  
14 overpayment. I outline these steps in this paper.

## 15 II. BASICS OF SUPPLY/DEMAND EQUILIBRIUM IN THE ENERGY MARKETS

16 5) We begin, however—as we must—with first principles. The current demand response  
17 debate seems to routinely disregard core market fundamentals. As in most markets, the  
18 starting point is access to correct *information*. Customers should see the cost or market

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<sup>4</sup> This price is largely consistent with the price endorsed by Prof. William W. Hogan, *Providing Incentives for Efficient Demand Response* (“Hogan Test.”), Attachment A to *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Motion for Leave to Answer and Answer of the Electric Power Supply Association (Oct. 30, 2009); *see also* Prof. William W. Hogan, *Implications for Consumers of the NOPR's Proposal to Pay the LMP for All Demand Response* (“Hogan Comments”), Attachment 1 to *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket No. RM10-17-000, Comments of the Electric Power Supply Association (May 12, 2010) (“EPSCA Comments”). The differences between LMP-F, as advocated by Prof. Hogan, Hogan Test. at 18, and LMP-C are technical and may be non-existent for many retail customers.

<sup>5</sup> To satisfy jurisdictional issues such a payment may be made to the demand responder by the wholesale market operator, and in turn, a charge of an equal amount made from the wholesale market operator to the load serving entity, LSE, wholesale customer.

1 price of a product; suppliers, in turn, should know how much of the product is being  
2 demanded by customers. These two pieces of information combine and result in price  
3 formation. Typically this all occurs informally. Parties shop around among various  
4 suppliers, comparing prices and products. This interaction between buyers and sellers  
5 yields a trajectory of prices that converge towards a balance where supply and demand are  
6 equal. No supplier is willing to provide more, as no purchaser is willing to pay above the  
7 incremental cost of the next unit of supply. Similarly, consumers will not buy less, as they  
8 gain value at least equal to the marginal cost of production of the last unit supplied.  
9 Ultimately, this process creates a uniform price for comparable products when adjusted for  
10 quality, time and location.<sup>6</sup>

11 6) In the organized wholesale electric markets, however, the process is more formal. Every  
12 few minutes a central system operator can determine the least cost incremental mix of  
13 resources across the system, while respecting transmission limitations, that should be  
14 dispatched to produce the next needed unit of energy. This results in the LMP. The  
15 customer *should* decide—in response to LMP—whether to purchase and consume power at  
16 that price. Similarly production and costs would adjust to reflect that incremental  
17 consumption. The problem—and the heart of the matter at issue in this NOPR—is that  
18 retail customers do not typically see or pay LMP. Customers pay a separate retail rate,  
19 wholly divorced from LMP faced by the wholesale purchaser, the LSE. The current  
20 organized wholesale markets thus suffer from a fundamental mismatch—a failure to  
21 communicate. One set of pricing resides under FERC jurisdictional control—production,

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<sup>6</sup> The Commission is doubtlessly aware of these basics set forth in any undergraduate textbook on microeconomics; they are repeated here preliminarily for the following discussion.

- 1 transmission, and bulk market sales to the LSE—and the other resides under retail (state by  
2 state) regulation—the retail sales between the LSE and retail consumer.
- 3 7) If the retail customers actually paid LMP, this would automatically create the exact right  
4 amount of demand response in reaction to the actual costs of power. It would occur  
5 automatically as demand adjusts to the most recent price signal. This result would be  
6 consistent with both basic economics and basic market design principles. Price would  
7 dictate how much power is consumed. There would be no necessity of intervention or side  
8 payments.
- 9 8) These core principles have already been presented in some detail to the Commission in  
10 numerous other statements in this combined docket and elsewhere.<sup>7</sup> I won't repeat these  
11 same sound and basic truths here, but they are ignored only at the peril of market  
12 efficiency. The Commission should exercise extreme caution when departing from these  
13 core principles, as the current NOPR proposes. Otherwise, all customers will pay for very  
14 material subsidies that result in inefficient demand response.
- 15 9) Dr. Hogan's analysis submitted in the EL09-68 docket demonstrates how an equilibrium of  
16 supply and demand reflects a price and quantity that are welfare maximizing for society as  
17 a whole. If there were additional value to be had by consumers from purchases at a given  
18 LMP, they would purchase more until the LMP increased and the incremental benefit was  
19 eliminated. As their purchases increased, so too would the LMP, reflecting the ever more  
20 expensive resources being required for production of the next unit of energy. Similarly, if

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<sup>7</sup> See, e.g., Hogan Test.; *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM (Oct. 16, 2009); Hung-po Chao, *Price-Responsive Demand Management for a Smart Grid World*, 23 *Electricity J.* 7 (2010) (“Chao”).

1 the cost of any increment of power exceeded the value to the customer, consumers would  
2 reduce their consumption until the value was less than or equal to the resulting LMP.

3 10) The implications of these basic facts on demand response and conservation are  
4 straightforward: if consumers see the right price, they consume the right amount. There is  
5 no need to pay them more for consuming less, nor is there any need for external  
6 intervention to subsidize different behavior. If consumers actually paid LMP, the notion of  
7 a side payment to modify future anticipated or avoided consumption would be a non-  
8 sequitur. Such consumption would not take place to begin with unless the value to the  
9 consumer equaled or exceeded the price as revealed by the LMP.

10 11) Indeed, the only result of such side payments would be to distort consumption levels from  
11 welfare maximizing levels. This distortion would come in the form of a tax on all  
12 consumers, with the proceeds going to the recipients of the subsidies. Someone has to pay  
13 the incentive to the party that decides not to consume power. But the recipient of the  
14 subsidy would not have consumed that power in the first place had it “seen” the right price  
15 (LMP). Such subsidies not only distort the efficient allocation of resources, but also  
16 constitute the same type of price discrimination that artificially depresses prices that the  
17 Commission itself has explicitly rejected in the capacity markets.<sup>8</sup>

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<sup>8</sup> By effectively creating a non-bypassable surcharge on other customers to subsidize the consumption of others, the Commission proposal creates two-tier pricing, and artificially suppresses aggregate demand, and associated prices and legitimate inframarginal rents for participating market suppliers. *See, e.g., PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 141 (2006) (“In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost-of-service regulation. ... This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices.”); *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005) (non-discriminatory single-clearing price capacity auctions “ha[ve] the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs” and have been “found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction.”); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 45 (2005) (paying all “generators the same market-clearing price creates incentives to minimize costs, because a generator’s cost reductions are retained by the

1 12) Simply said, the obvious solution here is to get the prices right, show them to consumers,  
2 and get out of the way. The notion that any level of consumption is too much, regardless of  
3 circumstances or use, or that less consumption is always better simply is not true. We  
4 cannot possibly predict as well as the market can how much demand response is the correct  
5 amount.<sup>9</sup> We are all better off as consumers and a society when we can equilibrate the  
6 marginal costs and values of products. LMP is designed to do just that. If consumers  
7 actually paid LMP, the resulting level of demand would be, by definition, just right.  
8 Absent explicit market failures (not present here),<sup>10</sup> movement away from these right  
9 quantities and prices should be a matter of concern for the Commission, not an objective.

### 10 *III. POTENTIAL JUSTIFICATIONS FOR DEPARTING FROM CORE MARKET PRINCIPLES*

11 13) Obviously reality does not always permit the best and simplest solution to a problem.  
12 Here, the Commission cannot set retail rates. Thus it is trying to do indirectly—through a  
13 subsidy mechanism—what it cannot do directly. However, even assuming that the  
14 Commission has no other options, there is little to recommend or support the Commission’s  
15 proposed demand response pricing. Deviations from the straightforward conclusion that

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generator and thus increase its profits” while paying “different amounts to different generators based on the level of compensation needed to keep the generator in operation would create a unit-specific cost-based system and undermine the advantages of a market for capacity.”); *New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,244 at P 65 & n.76 (2005) (“Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids [as] [t]his gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use[.]”); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 81 (2003) (“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 [more expensive] generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover, those are the types of market signals the Commission would expect to encourage new generation additions.”).

<sup>9</sup> See generally F.A. Hayek, *The Use of Knowledge in Society*, 35 Am. Econ. Rev. 519 (1945); see also Ludwig von Mises, *Die Wirtschaftsrechnung im sozialistischen Gemeinwesen* [Economic Calculation in the Socialist Commonwealth], 47 Archiv für Sozialwissenschaften (1920), available at <http://mises.org/pdf/econcalc.pdf> (English translation by S. Adler).

<sup>10</sup> See Affidavit of Alfred E. Kahn at 5, Attachment A to *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Comments and Protest of Demand Response Supporters (Sept. 16, 2009) (stating the absence of so much as “any assertion that there is such a market failure”).

- 1 the prices and associated consumption should be allowed to “speak for themselves” could  
2 only be justified if the market pricing lacks transparency and consumers have limited or no  
3 knowledge of the true LMP, and therefore cannot appropriately respond to the bulk  
4 wholesale electric price.
- 5 14) If there were some large impediment to price transparency, *e.g.*, a lack of appropriate  
6 meters or the inability to place consumers on dynamic/time of day pricing due to state  
7 jurisdictional constraints, the Commission’s proposal still misses the mark. It entirely fails  
8 to address such considerations or remedy such market limitations. Again, while it might  
9 make sense to increase access to better metering information, or to force all large customers  
10 on to time-of-use tariffs based explicitly on LMP so there is no missing jurisdictional link,  
11 there is no direct connection between improving such information, metering and  
12 transparency, and a subsidy set arbitrarily at LMP simply to not consume some potential  
13 future demand for power.<sup>11</sup>
- 14 15) Ignoring these factors, the NOPR seems to suggest another justification, reflecting some  
15 sort of empirical validation for increasing compensation for demand response. It observes  
16 that the level of participation in the PJM economic demand response programs declined  
17 with the removal of external subsidies.<sup>12</sup> This should hardly have come as a surprise; it is  
18 merely one more specific example of the Law of Demand known to economists since at  
19 least the 19th century.<sup>13</sup> Moreover, this is exactly what should be expected when taking

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<sup>11</sup> The Commission has demonstrated the power to do so, at least when the retail user so wishes: Any retail consumer has a right to become a *de facto* wholesale consumer through an intermediate affiliated single-user LSE paying LMP at the point of withdrawal. *See Occidental Power Servs., Inc. v. PJM Interconnection, L.L.C.*, 103 FERC ¶ 61,285, *reh’g denied*, 104 FERC ¶ 61,289 (2003).

<sup>12</sup> NOPR at P 10.

<sup>13</sup> Alfred Marshall, *Principles of Economics* 174 (4th ed., MacMillan 1898) (“There is then one general *law of demand*, viz. that the greater the amount to be sold, the smaller will be the price at which it will find purchasers; or,

1 basic economic principles into account. Why should it be a surprise or cause for action that  
2 people increased their consumption to a level consistent with the value they placed on the  
3 power, or conversely, why people didn't continue to reduce their consumption when  
4 subsidies not to consume (even when otherwise economic) were removed?

5 16) Indeed this increased consumption was both predictable and desirable, as absent any  
6 specific market failings, it is indicative of consumers making better decisions about the use  
7 of resources. I personally witnessed just this type of behavior by one of my own industrial  
8 clients in PJM, who, when faced with the elimination of such subsidies, reinstated  
9 otherwise profitable manufacturing operations. The only reason the manufacturing was  
10 curtailed in the first place was not that the cost of power was too high, but rather that the  
11 subsidy being provided exceeded the otherwise achievable profits from operation. This is a  
12 clear indication of the inefficiency of the subsidy as well as the inherent flaw of using the  
13 relative level of consumption in response to such subsidies as a metric for the effectiveness  
14 of conservation and demand response programs. The real concern should be why  
15 otherwise profitable manufacturing efforts were being ceased based on subsidies from third  
16 party wholesale electric ratepayers.

17 17) In short, there is no justification to depart from market fundamentals in this case. In  
18 addition, the Commission's proposed payment scheme (LMP in all hours) is arbitrary. As  
19 discussed further below, even if it was justified for the Commission to intervene with a  
20 subsidy program or payment to attempt to replicate private business or contract actions  
21 related to electric consumption, the proposed subsidy here is wrong. The payment of LMP

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in other words, that the amount demanded increases with a fall in price, and diminishes with a rise in price.”). As another great economist, personally fortunate to have lived long enough to see the Nobel Prize in Economics established, noted, it would be the discovery of a true *counter-example* to the Law of Demand that would “assure[ any economist] of immortality, professionally speaking, and rapid promotion.” George J. Stigler, *The Theory of Price* 24 (3d ed., Macmillan 1966) .

1 for perceived reductions in the use of power is too high, and would create inefficiencies  
2 (assuming one could ever justify taking the step to create the private transactional proxy  
3 regarding the use of electricity by consumers in the first place).

4 18) Conversely, the harm in the proposed policy is explicit and direct. By taxing some  
5 consumers to pay subsidies that artificially reduce demand and prices, allocative efficiency  
6 is decreased, and a form of price discrimination is introduced which harms all incumbent  
7 suppliers, and makes the markets riskier and less attractive for new suppliers. As discussed  
8 in the next section, when seen in this light these types of unnecessary excess payments to  
9 suppress price and demand are no different than the type of uneconomic entry that the  
10 Commission has already condemned in the capacity markets in PJM, NYISO and ISO-NE.  
11 It is inappropriate to pursue such a discriminatory process, already linked to the exercise of  
12 market power in the capacity markets, via a Commission directed subsidy in the energy  
13 markets.<sup>14</sup>

14 *IV. WHY THE COMMISSION'S RECOMMENDATION IS A FORM OF DISCRIMINATORY*  
15 *PRICING*

16 19) Aside from being economically unjustified, the Commission's proposal to pay LMP to  
17 demand response in all hours is also a form of discriminatory pricing that artificially lowers  
18 prices. Indeed, if this action was not taken or approved by the Commission itself, it would  
19 seem a reasonable conclusion that this type of pricing would represent the exercise of  
20 oligopsony (buyer) market power, and based on other Commission precedents, be  
21 prohibited.

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<sup>14</sup> *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81. Similarly, the Commission endorsed uniform market clearing prices for all participants, new entrant or existing. *See id.* at PP 77, 81.

- 1 20) In fact, it is one of the so-called “benefits” of subsidized demand response that make this  
2 type of discriminatory pricing the most visible. It is often noted that by reducing the  
3 consumption of just a few parties, the overall clearing price for the market as a whole is  
4 reduced, with the implication being that the benefit of the reduction of the few should be  
5 valued at the overall price reduction times the remaining total demand in the market as a  
6 whole. For example if reducing demand by 1000 MW from 101,000 MW to 100,000 MW  
7 resulted in the LMP declining by \$10 per MWh, then the claimed benefit is \$1,000,000 for  
8 that action, or \$1000 for each MW reduction.
- 9 21) This logic is flawed. Even if the reduction in demand were rational and based on a proper  
10 consideration of price of the power versus its value to the consumer, the “benefit” isn’t the  
11 change in total payments, as these are really just shift in rents between market  
12 participants.<sup>15</sup> However, what is most disturbing is that this action is really an exercise of  
13 market power to use a subsidy from some consumers to artificially suppress demand and  
14 prices to below the competitive outcome. This results in the under-compensation of all  
15 suppliers.<sup>16</sup>
- 16 22) That this type of exercise of market power is wrong can be seen by direct analogy to  
17 actions on the supply side. Assume that to drive up prices, a small group of suppliers were  
18 paid a subsidy to economically or physically withhold their production from the market.  
19 Prices would increase, but demand would decrease. Further, margins for those suppliers

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<sup>15</sup> Hogan Test. at 3 (“Some of the comments submitted in this proceeding apparently assume that maximizing social welfare and minimizing the price that is paid by load are similar objectives. They are not, for essentially the same reason why maximizing social welfare is not the same as maximizing the revenues that suppliers receive.”).

<sup>16</sup> Even experts offering testimony for states against NEPGA taking an extremely limited view of buyer market power say that “[a] buyer exercises market power by withholding purchases.” Direct Testimony of James F. Wilson at 33:1-2, Exhibit DPUC-1 to *ISO New England Inc.*, Docket No. ER10-787-000, Motion to Answer and Answer of the Connecticut Department of Public Utility Control, *et al.* (Mar. 30, 2010). This is of course what a demand response program does: Lowering prices beneath competitive levels by bribing some consumers to withhold their purchases through payment of a bribe (rather than merely avoiding the paying the market price).

1 remaining in the market would be increased by the artificial reduction in supply, while  
2 those withholding would be held profitable via the subsidy from other suppliers. This  
3 would be classic oligopoly behavior, and clearly anti-competitive. The Commission's  
4 pricing proposal is the mirror image of this.

5 *V. DISCUSSION: HOW DID WE GET HERE?*

6 23) Before turning to my specific recommendations, it is instructive to first take a quick  
7 historical detour. As discussed above, the current NOPR's pricing proposal is manifestly  
8 inconsistent with basic economics and market design principles.<sup>17</sup> It is also discriminatory.  
9 But since it is known that subsidy proposals to obtain more and more demand response and  
10 conservation—like those at issue here—suffer from these serious flaws, why are they  
11 nevertheless an accepted industry practice and continue to at least appear to be so attractive  
12 to the politically attuned?

13 24) Paying electricity consumers extra so that they will not consume perhaps made some sense  
14 in limited, exceptional circumstances in the past, but can no longer be justified today or as  
15 a general long-term policy. Through the years, however, a general belief has arisen that  
16 demand response and conservation are *always* good and must be encouraged and

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<sup>17</sup> See generally *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket RM10-17-000, Comments of Charles J. Cicchetti, Ph.D. (Apr. 27, 2010); Dr. Larry E. Ruff, Harvard Elec. Policy Group, *Economic Principles of Demand Response in Electricity* (2002), [http://www.hks.harvard.edu/hepg/Papers/Ruff\\_economic\\_principles\\_demand\\_response\\_eei\\_10-02.pdf](http://www.hks.harvard.edu/hepg/Papers/Ruff_economic_principles_demand_response_eei_10-02.pdf). ("Ruff"); Monitoring Analytics, LLC, *Barriers to Demand Side Response in PJM* (2009), [http://www.monitoringanalytics.com/reports/Reports/2009/Barriers\\_to\\_Demand\\_Side\\_Response\\_in\\_PJM\\_20090701.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/Barriers_to_Demand_Side_Response_in_PJM_20090701.pdf) ("July 2009 IMM Report"); Monitoring Analytics, LLC, *PJM Regulation Market: Impact of December 1, 2008 Changes in Market Design, December 1, 2008 – October 31, 2009* (2009), [http://www.monitoringanalytics.com/reports/Reports/2009/IMM\\_PJM\\_Regulation\\_Market\\_Impact\\_20081201\\_Changes\\_20091130.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf); Hogan Test.; Hogan Comments; EPSA Comments; Chao, *supra* note 7; David Lawrence, New York Independent System Operator, *NYISO Response to FERC NOPR on Demand Response Compensation in Energy Markets* (May 10 2010), available at [http://www.nyiso.com/public/webdocs/committees/bic\\_prlwg/meeting\\_materials/2010-05-10/NOPR\\_on\\_DR\\_comp\\_MP\\_overview.pdf](http://www.nyiso.com/public/webdocs/committees/bic_prlwg/meeting_materials/2010-05-10/NOPR_on_DR_comp_MP_overview.pdf); *PJM Interconnection, L.L.C.*, Docket No. EL09-68, Motion to Intervene and Protest of Robert J. Borlick Opposing PJM's Proposed Tariff Changes (Sept. 16, 2009); *PJM Interconnection, L.L.C.*, Docket No. EL09-68, Robert L. Borlick's Response to the Demand Response Supporters' Witnesses (Sept. 28, 2009); *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Docket No. RM10-17-000, Comments of the PJM Power Providers Group (May 12, 2010) ("P3 Comments"); Affidavit of Jeffrey Tranen, Attachment A to the P3 Comments.

1 subsidized. This is a fallacy. Demand response and conservation *are* good, but there can  
2 be too much of a good thing. When consumers are exposed to the right price, they make  
3 better decisions about how much demand response is correct than they will if they receive  
4 artificial subsidies.

5 25) Dr. Larry Ruff has provided a useful summary of historic events going back to the 1970s to  
6 help us understand how we got here.<sup>18</sup> This review provides a constructive context as to  
7 why there appears today to be such an apparent bias to a set of policies that distort prices  
8 and discriminate, contrary to basic economic principles and a long tradition and set of  
9 precedents for Commission decision-making.

10 26) While the story may begin earlier, my own experience started with my first day of work at  
11 Institute for Defense Analysis in October 1973, just as another Arab-Israeli war was about  
12 to break out. My immediate work assignments were related to energy issues, global  
13 logistics related to petroleum supplies and domestic energy issues, including electricity  
14 production. My perception is that this was the onset of the combination of conditions that  
15 lead to the current bias in favor of incentives and subsidies for demand response over  
16 simply pursuing more accurate pricing policies and the communication of those prices to  
17 consumers.

18 27) A number of factors all came into play at once. First, and most important, due to spikes in  
19 fuel prices, short run marginal costs were much higher than average embedded costs, which  
20 were the basis for retail rates. Second, there were no organized wholesale markets or RTOs  
21 to create transparent wholesale prices. Third, retail customers effectively had a fixed price  
22 call on their utilities for as much power as they wanted at historic average costs. Fourth,

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<sup>18</sup> Ruff, *supra* note 17, at 4. Any specific interpretation or representation of that content reflects my own views and not necessarily those of Dr. Ruff.

1 rapid adjustment mechanisms such as fuel factors that might allow retail rates to rapidly  
2 increase and keep up with rising marginal production costs were rare and most efforts by  
3 vertically integrated utilities to gain access to such mechanisms were being strongly  
4 resisted by consumer interests. Fifth, capital costs for new generation facilities were also  
5 increasing rapidly, with the resulting long-term marginal costs also exceeding average  
6 prices. Sixth, despite price run ups, demand for electric power was still growing strongly  
7 and this seemed to contribute to a general perception of scarcity, most likely in the context  
8 of perceived fuel scarcity. Seventh (and last), a sort of national unity developed around  
9 responding to a foreign threat posed by dependence of fuel from often-hostile sources.

10 28) Two factors in particular stand out (my first and third factors in the prior paragraph): the  
11 fact that short term marginal costs were rising rapidly and exceeding average rates, and the  
12 existence of what amounted to a fixed price call by consumers for as much additional  
13 power as they wanted at the established retail rate. This call concept is key to  
14 understanding the situation. Unlike the current wholesale organized markets, under the old  
15 retail/wholesale status quo, customers effectively were guaranteed power for fixed prices  
16 (the retail price tariff or strike price) for as much as they chose to consume at the filed retail  
17 tariff, typically reflecting unitary charges designed to recover average costs based on an  
18 estimated total consumption for the entire utility. Regulators had effectively imposed the  
19 fixed price call obligation on suppliers. You could buy as much as you wanted at the  
20 average rate embedded in those tariffs.

21 29) In this historical situation, these two factors meant that for every additional unit of energy  
22 sold, the retail supplier was losing money. Retail rates understated true marginal costs,  
23 there was a call or right by the customer to purchase more at the fixed retail rate, and there

1 was almost no ability for the suppliers to “catch up” via revised rates reflecting the higher  
2 marginal costs. On top of this was the very real perception of fuel scarcity due to embargo  
3 and the visible turmoil in energy markets, particularly petroleum.

4 30) In many ways this created a “perfect storm” in favor of a perceived universal benefit to  
5 conservation and demand response. All sides had seemingly convergent agendas. There  
6 was strong political consensus to reduce dependence on foreign oil through conservation.  
7 In addition, Congress created the Federal Energy Office and the Energy Research and  
8 Development Administration. It converted the Federal Power Commission into the Federal  
9 Energy Regulatory Commission. Congress enacted the National Energy Act of 1978.<sup>19</sup> At  
10 the same time, there were very strong direct financial incentives within the utility industry  
11 (and their shareholders) to curb consumption to reduce losses on marginal sales until  
12 average retail rates could increase.

13 31) Against this background the “less is more” ethic seemed to take on its own life, and  
14 demand response and conservation initiatives became a key part of national energy policy.  
15 These policies were economically rational using the same basic notions that I previously  
16 discussed. If the true price of power was much higher than what was actually being  
17 charged, than the resulting increased consumption was inefficient. In these circumstances,  
18 it made sense to both get the right price in front of people, and consciously pay them to  
19 limit consumption in order to reduce economic and efficiency losses. Prices were not  
20 reflecting the true cost of power, and “buying out” the fixed price calls held by retail  
21 consumers in order to avoid real economic losses by suppliers (the vertically integrated  
22 utility) was good economics and good business.

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<sup>19</sup> This act included among others the Public Utility Regulatory Policies Act (“PURPA”) and the National Energy Conservation Policy Act (“NECPA”).

1 32) However, as time progressed, the strong policy in favor of demand response and  
2 conservation survived even as some or all of the initial and important factual conditions  
3 disappeared. In particular, the two key considerations that at one point justified paying  
4 consumers not to consume—marginal costs in excess of the average being charged  
5 combined with the fact that consumers had what amounted to the fixed price call on  
6 unlimited consumption—both no longer applied generally, and clearly not in the organized  
7 wholesale energy markets being addressed in the NOPR. Absent these two conditions, the  
8 political incentives and considerations may have remained the same, but the real economic  
9 justification behind paying consumers not to consume (absent market failures) disappeared.

10 *VI. TRANSLATION INTO ORGANIZED WHOLESALE MARKETS*

11 33) The key observations from the above history lesson are that the two essential conditions to  
12 justify subsidies to demand response are simply not met within wholesale markets with  
13 LMP pricing. While some of these issues remain in the non-jurisdictional retail area, for  
14 the most part these two conditions have been resolved in the organized wholesale markets.  
15 First, there is no disconnect at the wholesale level between the short-term energy price and  
16 the costs to customers. It is the LMP. Second, there is no fixed price call of unlimited  
17 quantities between the customer and the wholesale market (other than at the market cap  
18 prices). As demand increases, so do prices in the wholesale spot markets (LMP). Without  
19 these two elements, any economic justification for subsidized or out of market payments  
20 for demand response disappears.

21 34) It is worth considering each of these elements further. At the wholesale level, the LSE sees  
22 the right wholesale price, the LMP. To the extent that there is any disconnect here, it is not  
23 in the wholesale pricing (although some might argue that there should be even more  
24 granularity in the LMP nodal prices). Rather, the disconnect is between what LSEs

1 purchase power for in the wholesale market (LMP), and what they sell it for (or are  
2 obligated to sell it for) in the retail markets (some retail rate, what we designate here at the  
3 margin as “C”). This is a retail rate design problem. That is, the wholesale rate to the LSE  
4 at the “right” LMP price doesn’t necessarily match the rate the consumer sees.

5 35) And this in fact directly links to the second point. There is no fixed price call with an open  
6 quantity by the LSE on the wholesale market operator. The LSE purchases power at the  
7 LMP. Other than at the market cap prices, the notion of a call doesn’t exist. There is no  
8 fixed price option from the RTO for the LSE. An LSE may seek one via a private bilateral  
9 agreement, but that is a separate business arrangement and judgment. And while there is  
10 not an explicit limit on the volumes of purchases that an LSE can make, there is an implicit  
11 limit via the adequacy designs of each market. Thus here again, the mismatch doesn’t exist  
12 at the wholesale level as the LMP increases with demand, but only potentially at the non-  
13 jurisdictional retail level (where retail prices may be fixed regardless of increases at  
14 wholesale). To the extent that a party might have a fixed price call for an open quantity of  
15 energy at a price that is below market, such a call resides between the LSE and its retail  
16 (non-jurisdictional) customer. It is not directly within the scope of the wholesale market  
17 design.

18 36) The implications of the current absence of these two conditions under the organized  
19 wholesale market design are clear. There is no reason for any subsidy to encourage  
20 demand response at the wholesale level, as the price (LMP) is directly conveyed to the LSE  
21 purchaser. Neither is there any out-of-market call held by any purchaser against the market  
22 supply<sup>20</sup> that might serve as motivation for someone to buy out the call when the call’s

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<sup>20</sup> Certainly any two parties are free to enter into such call agreements. The point here is that no LSE in the market holds any such call against the organized market itself.

1 strike price is below the wholesale market price. The call, to the extent it exists, is between  
2 the LSE (the wholesale customer) and the retail customer. Thus this arrangement is outside  
3 of the Commission's jurisdiction.

4 37) This also begs the obvious question of "who pays" if there is no counterparty to buy out the  
5 difference between the call price and the LMP. The clear answer, and the source of the  
6 inefficiency, is that this payment only occurs via subsidies by consumers as a whole. This  
7 is not only inefficient, but presumably serves as a strong disincentive to rationally invest in  
8 equipment, information and procedures to appropriately modify consumption in response to  
9 actual market prices without a subsidy. This can only be reasonably addressed, if as in the  
10 recommended strategy discussed below, the buyout cost of an imputed retail call with a  
11 strike price lower than LMP is assigned directly to the LSE serving the retail load that  
12 holds or has been given the call option. This type of payment results in a "wash" for the  
13 LSE, and also importantly results in no subsidies or uneconomic transfers between other  
14 market participants.<sup>21</sup>

## 15 VII. RECOMMENDATIONS

### 16 A. *The Best Approach—Let Consumers See and Pay LMP*

17 38) As the above summary of the "basics" makes clear, it would seem in the first instance that  
18 the right action by the Commission is not to create subsidies or other incentives for demand  
19 response and conservation, but to simply allow the "right" price to be seen and acted upon

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<sup>21</sup> This assignment of costs is what was in the original PJM economic demand response design. General subsidies to all LSE's only occurred when payments went from LMP-C, to LMP, with the difference being socialized. *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing at 29-35 (Aug. 26, 2009). It is a wash for the LSE because the LSE avoids a purchase at LMP and a sale at the lower cost C, and thus breaks even by paying the retail load the same amount it would have had to pay if consumption wasn't reduced;—LMP minus C.

1 by consumers. This would bring the wholesale electric markets and retail energy  
2 consumption in line with basic economic and market design principles.

3 39) With this in mind, I have identified two general recommendations to improve demand  
4 response and the efficiency of electric power consumption. Neither is based on  
5 compensation for perceived reductions in use based on the payment of 100% of the LMP,  
6 the Commission's proposed solution. The first is what I call the "best" approach to solving  
7 the demand response problem. The second is a very reasonable "second best" approach,  
8 which I understand is endorsed by NEPGA,<sup>22</sup> and accounts for the reality of the separation  
9 in retail and wholesale rate jurisdiction while offering the correct level of compensation for  
10 the conservation action.

11 40) *First*, the Commission should take all actions within its jurisdictional control to make sure  
12 that consumers see actual dynamic wholesale LMP pricing and that the pricing itself is  
13 accurate. This could be something as simple as requiring all customers with a load above a  
14 definite level to become direct wholesale customers subject to hourly interval metering  
15 capable of supporting LMP based real time pricing. This would be a direct way to  
16 communicate the "right" prices and allow load/demand to respond to prices and in turn  
17 appropriately adjust their consumption. It would eliminate any rationale for the market  
18 operator to engage in any inappropriate pricing or subsidies and permit efficient demand  
19 response to occur through the combined wholesale and retail market. It would also  
20 eliminate the need for the Commission's proposal. Essentially, the Commission should just

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<sup>22</sup> A similar second-best approach was endorsed by Prof. Hogan, Hogan Test. at 18, and generators in PJM, *PJM Interconnection, L.L.C.*, Docket No. EL09-68-000, Motion for Leave to Answer and Answer of PJM Power Providers Group at 3 (Oct. 30, 2009); P3 Comments.

1 act to get anything it can out of the way between the consumer and the consumer's  
2 recognition of the correct LMP.

3 41) Because so much demand is concentrated in a relatively small number of the largest  
4 customers, even moderate levels of mandatory switching of large customers to direct  
5 wholesale status have the potential to expose a very large portion of the market to direct  
6 price signals and response.<sup>23</sup> In a sense, this is the most effective demand response  
7 initiative, and it is free but for the cost of information, and possible regulatory  
8 impediments.

9 42) The most commonly discussed impediments to demand response are metering limitations  
10 and data constraints. If so, sending inefficient subsidies to create artificial markets for  
11 demand response such as in PJM, which diverts funds from consumers to third parties,  
12 makes little sense. Presumably such subsidies would end when either appropriate pricing  
13 policies were put in place or sufficient load was mandated to "see" the right price. This  
14 would result in a permanent resolution rather than a temporary subsidy and transfer of  
15 funds to third parties.<sup>24</sup>

16 43) Here I think there is quite a bit of constructive action that can be taken immediately. The  
17 simplest action that I can envision is to permit all customers to face day ahead and real time

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<sup>23</sup> For a number of years I have attempted to get information on customer size distributions and have not yet received or discovered direct source information. In most industries it would not be surprising to see the majority of demand concentrated in less than 10% of customers, allowing even a relatively small penetration of customers facing dynamic pricing to impact the demand response of a very large portion of the overall electric demand. Further, such information would likely be received by the parties most able to accurately assess and respond to this information. As a corollary to this recommendation I would suggest the Commission request information from all organized markets on the per cent of total demand from customers whose load exceed 1, 5, 10, 25 and 50 MW etc.

<sup>24</sup> Based on the statement of the PJM market monitor, Dr. Bowring, it appears that in 2007, the subsidy in the PJM energy demand response was on the order of \$17 million. July 2009 IMM Report at 22 n.34. One might assume that a significant amount of metering and telecommunications equipment, provided to the largest customers lacking such resources could permanently impact demand response if these funds were targeted on such impediments rather than subsidies to customers who likely already have such metering resources, and associated payments to third parties.

1 prices based directly on LMP calculations.<sup>25</sup> If implemented, this would be the quickest  
2 and most efficient mechanism of getting responsive and elastic pricing behavior into the  
3 markets to achieve appropriate demand response. Though I don't have direct information, I  
4 assume, as is the case in virtually all markets, that the great majority of electric demand is  
5 concentrated within a relatively small number of clients.

6 44) I would recommend that the Commission collect information on the concentration of large  
7 customers, and direct its efforts to the creation of infrastructure to allow all "large"  
8 customers to receive appropriate dynamic pricing signals and actively control their electric  
9 demand without artificial price intervention.

10 45) This recommendation is consistent with working towards the welfare maximizing solution  
11 that would be most desirable. Both actions are amenable to relatively simple fixes,  
12 assuming jurisdictional hurdles can be overcome.

13 *B. The Second-Best Approach—Bridging the Gap Between Wholesale and Retail Pricing*  
14 *Jurisdiction*

15 46) My second recommendation directly addresses the regulatory gap that creates most of the  
16 problems by demonstrating a manner in which to set the desired incentive for demand  
17 response at a level that does not result in the uneconomic and discriminatory subsidies  
18 associated with the Commission's proposal. I call it the retail proxy call approach. Under  
19 this approach, the market operator seeks to replicate a private "call" type transaction  
20 between retail load and its supplier LSE, and in doing so deduces or infers a reduction in  
21 demand and associated "savings" associated with such demand.<sup>26</sup>

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<sup>25</sup> A retail consumer already has a right to become a *de facto* wholesale consumer through an intermediate affiliated single-user LSE paying LMP at the point of withdrawal. *Occidental Power Servs.*, 103 FERC ¶ 61,285, *reh'g denied*, 104 FERC ¶ 61,289 (2003).

<sup>26</sup> This varies slightly in description, but not in economic content, from the proposal in NEPGA's pleading: Retail consumers receive payment from their LSE, directly or indirectly, for the quantity they reduce their consumption

- 1 47) This retail proxy call type program attempts to replicate a situation where a fixed price call  
2 on an open quantity of power exists between the buyer and seller, and the demand response  
3 action is related to the “buy out” of the call option when market prices exceed the strike or  
4 call price. In this context if we define  $C^{27}$  as the marginal cost to the retail supplier for the  
5 increment of verified demand reduction that occurs, then the demand responder is paid  
6  $LMP-C$ , for all periods where  $LMP$  is greater than  $C$ , this is the logical “buy out” price. It  
7 is not the Commission’s proposed value of 100% of  $LMP$ . When viewed as this type of  
8 call or option, with  $C$  as the agreed LSE/consumer strike price, it makes it clear that the  
9 rational action by the LSE is to “buy out” the call via a payment equal to the amount that  
10 the call option is “in the money,” which is exactly  $LMP-C$ .
- 11 48) Most importantly, this results in the communication of just the right prices and incentives  
12 to all of the parties involved. The LSE is effectively held harmless, to the extent that the  
13 LSE avoids being forced to make a purchase at  $LMP$  when the LSE’s marginal income if  
14 the purchase by the consumer were made would only be  $C$  (with the LSE thus losing  $LMP-$   
15  $C$ ). If the consumption doesn’t occur, the purchase and sale do not happen, and a payment  
16 is made to the consumer of the same amount  $LMP-C$ , then the payment equals the loss that  
17 the LSE avoided. Similarly the consumer sees the right price signal regarding demand

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below baseline level at a price equal to  $LMP-C$  (whenever  $LMP$  exceeds  $C$ ). One helpful way of financially describing this relationship is to say that retail consumers pay  $LMP$ , but are assigned a number of options on energy equal to their baseline consumption, each with a strike price of  $C$ .

<sup>27</sup>  $C$  reflects the highest marginal cost that would have been incurred by the retail customer over the billing period of relevance. It may include generation, transmission, fixed overhead, etc. It really doesn’t matter what is included other than it is the marginal rate at which the retail customer could “call” on power from the LSE. Technically it must be understood that there is not necessarily a temporal match between the  $LMP$  at the time of demand response and the exact  $C$  charge that the retail customer may be incurring at that same moment. For example for customers whose retail rates are structured with increasing marginal blocks,  $C$  would reflect the charge associated with the highest marginal block that the consumer would have incurred but for the demand response, regardless of when the customer starts to be billed at this specific highest rate and regardless of the actual time of the demand response during the billing period.

1 response, LMP (*i.e.*, it receives a payment for the reduced consumption of LMP-C, and  
2 avoids paying the purchase price for that power of C, netting LMP).

3 49) For the retail consumer participating in a demand response program, economically the  
4 transaction splits into two parts under this type of proxy call proposal, whenever LMP  
5 exceeds C: (1) buying as much power as it wants at LMP; and (2) holding a number of  
6 power options equal to its baseline consumption with a strike price of C. The first, by  
7 exposing the retail consumer to LMP, gives it just the right incentive to conserve. The  
8 second, because it depends only on the consumer's *baseline* consumption, rather than its  
9 actual consumption, will not distort its consumption behavior, but merely hold it financially  
10 harmless if it cannot reduce demand. In practical effect, the consumer may use some of its  
11 options to offset LMP (that is, in effect, buying power at C, rather than LMP) and sell off  
12 its remaining options (that is, the number of options corresponding to how much the  
13 consumer reduced its consumption beneath its baseline) for LMP-C each, the standard  
14 value of an in-the-money option. This is a common market result based on an analogy to  
15 current market products, and makes more transparent the complexity that is often  
16 associated with transactions associated with demand reduction. These funds would come—  
17 directly or indirectly—from the LSE who would otherwise supply the retail load that is  
18 curtailing its consumption below the imputed call quantity. The LSE would nevertheless  
19 be held harmless because it saved exactly the same total amount because, for every unit of  
20 demand reduction, the LSE did not have to buy power at a high LMP and sell it at a lower  
21 C.

22 50) This type of structure is similar to what PJM implemented in its economic demand  
23 response program. I find this proxy retail an instructive structure for comparison because it

1 also demonstrates how one might achieve the potential imputed or hypothetical reductions  
2 in demand. These reductions are effectively based on non-existent but hypothesized energy  
3 calls by retail customers on wholesale market suppliers. However, under the retail proxy  
4 call, we can translate this to specific demand response because a “real” call does exist,  
5 between the LSE and the consumer. Thus the measurement or quantity element of such  
6 changes in wholesale payments (payments to consumers and charges to LSEs) represent an  
7 attempt to simulate what are deemed to be desirable interventions to uneconomically  
8 reduce consumption of electricity that should really be based on retail decision making and  
9 pricing based on the “buyout” of the call option held by the retail consumer and “sold” by  
10 the LSE.

11 51) Such a proxy program works in several stages. First, it is predicated on the existence of a  
12 call between the LSE and retail customer at a specified strike price (retail rate) which is  
13 marginally valued at a known amount  $C$ . Second, it assumes that such a call has a known  
14 quantity or reference amount for any given point in time. This is often referred to as the  
15 customer baseline (“CBL”), or some equivalent measure of what the customer might have  
16 consumed but for its demand response or conservation action. Third, it then estimates the  
17 magnitude of the reduction in actual consumption from the assumed CBL. This is the “buy  
18 out” quantity of the call option. Fourth, it makes a payment to the customer based on the  
19 reduction and some measure (subject to debate) related to the market value of energy or  
20 LMP less the strike price  $C$ . Finally, the charge for this payment of LMP minus  $C$  is  
21 assigned to the consumer’s LSE, the party who would have paid that same amount to  
22 liquidate the “in the money” call or otherwise incur an equal cost if the actual power was  
23 delivered instead of “conserved.”

- 1 52) Overall this allows the wholesale market operator to effect a set of payments that are the  
2 equivalent of the “right” compensation for the consumer based on the value of the power  
3 (LMP), but adjusted for the intervening retail rates that effectively set the call strike price at  
4 C.
- 5 53) This approach is notable in that it seems most similar to what is implied by the  
6 Commission’s NOPR as a means of implementation of the desired subsidies for demand  
7 response, and also for the complications and limitations that occur at each step. But  
8 analyzing each step reveals serious shortcomings in the Commission’s proposal as well as  
9 the practical problems associated with the actual implementation of any such proxy  
10 programs.
- 11 54) With respect to the first assumption, there is, in fact, no call. The only way to create an  
12 entitlement to power of any sort at a price less than market is to assume the existence of the  
13 call. That is, if the customer is to be permitted to sell back something to the market, it  
14 presumably must have had to purchase something in the first place, in this case the  
15 assumed call. However, in reality, there was no wholesale call, and neither was there any  
16 payment for the call. Thus, without properly taking account of the call, demand response is  
17 selling back something that it does not own. It is like me selling my neighbor’s house.<sup>28</sup>  
18 We only can overcome this recognition by seeing the wholesale market operators action as  
19 a proxy for the efficient buyout of the call that does exist, between the LSE and the  
20 consumer.

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<sup>28</sup> “Normal markets allow consumers to sell what they do not consume as long as they own it, but no rational market pays consumers for not consuming what they do not own, even if they can prove that they would have bought it but didn’t. Paying somebody because they might have bought more but didn’t is as illogical, unfair, and inefficient as buying the Brooklyn Bridge from somebody who thought about buying it but decided to sell it instead.” Ruff, *supra* note 17, at 4.

- 1 55) This says nothing of the complications inherent in the second and third assumptions, that a  
2 baseline of consumption (CBL) or reference level can be reasonably established, and that  
3 departures below such levels can be identified, measured and verified. Both are difficult  
4 tasks, prone to both technical complications and gaming.<sup>29</sup> For example, should the CBL  
5 change with weather, time of day, production schedules at a factory, overall demand for a  
6 factory's products, outages of production equipment at the factory, or any of the literally  
7 hundreds of different individual actions that constitute the aggregate demand of a  
8 manufacturing or operating facility consuming electricity? In some fashion these factors  
9 must be accounted for on a day to day, hour to hour, basis, in order to establish a legitimate  
10 CBL or its equivalent.
- 11 56) Similarly, how should reductions from the CBL or its equivalent be measured? If  
12 production is low due to the economy rather than "real" demand response, should that  
13 warrant the payment of a subsidy? If production is shifted to lower cost hours, but total  
14 demand is the same, should such use be rewarded beyond the lowered production costs  
15 with a 100% subsidy, or perhaps less? Similarly, it should be clear that to optimally  
16 address all of the measurement and verification issues, the exact same type of metering  
17 information and pricing transparency that would be necessary for the most direct approach  
18 (showing the right price and doing nothing) would optimally already be in place.
- 19 57) This discussion of the necessary assumptions required for steps 2 and 3 is relatively  
20 simplified. Stakeholder meetings have gone on for years in many RTOs over the details of

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<sup>29</sup> The difficulty of this task was discussed in detail only recently by ISO-NE's Director of Market Strategy and Analysis. See Chao, *supra* note 7, at 10-17. Dr. Chao also discusses the equivalent of the NOPR, under which consumers pay regular retail rates and receive a subsidy of the full LMP for demand reduction, *id.* at 14-16 (this is the equivalent of Dr. Chao's "case 3"), and demonstrated that it was not only worse than the first-best solution of exposing consumers to LMP at all times, *id.* at 13-14, but could actually be *worse than having no energy market demand response at all*, *id.* at 15-16 ("the social welfare losses [caused by the equivalent of the NOPR] could outweigh the benefits of price-responsive demand.").

1 these assumptions and how they should affect demand response payments. Some  
2 indication of the type of effort is presented by Monitoring Analytics, LLC in the July 2009  
3 IMM Report and associated statements in the regular PJM State of the Market comments.  
4 Here the market monitor discussed some of the efforts over time to improve the  
5 measurement and verification requirements that go along with steps two and three. From  
6 my perspective, the key observation here is that an enormous amount of energy goes into  
7 developing assumptions about metrics that are inherently weak, and ultimately more  
8 complex and subject to potential manipulation than simply putting in accurate real time  
9 metering and pricing information. None-the-less, given confidence in the execution of these  
10 steps, the resulting retail proxy call payment of LMP-C establishes the correct level of  
11 compensation.

12 58) Finally, it is the fourth assumption, compensation, that completes the circle and brings us  
13 back to the starting point regarding the Commission's proposal: that is to pay 100% of  
14 LMP in all hours for the hypothesized reductions determined under assumptions 2 and 3.  
15 My discussion above demonstrates why this proposal is incorrect. Even if we are willing to  
16 ignore what theory tells us, and ignore the practical problems of the first three assumptions,  
17 it ought to be clear that the "right" compensation given that there is an imputed call is the  
18 difference between LMP and whatever the call's strike price was (C).

19 59) This could only be 100% of LMP if the call entitled the purchaser the power for free,  
20 which is very unlikely. The call analogy thus demonstrates the fallacy of paying full LMP  
21 to demand responders while clearly identifying the right level of compensation.

22 60) This observation also simplifies the continuing debate about whether the subsidy should be  
23 100% of LMP, LMP minus some generation related component of a retail purchase

1 entitlement or LMP minus some generation and transmission related component of a retail  
2 purchase entitlement. The answer is straightforward, it is LMP minus the assumed strike  
3 price, and the strike price is whatever the customer could have purchased the power for  
4 absent the call entitlement. It doesn't matter what goes into that entitlement. If you built  
5 this entire logic based on the assumption that someone could buy the power for \$X, and  
6 LMP is higher than \$X, then the value of the call under this model of assumed behavior is  
7 LMP-\$X, regardless of what X represents.

8 61) Similarly, the debate regarding who is eligible for such programs is also clarified by this  
9 view. It should be obvious that if a customer is currently on dynamic pricing, then X is  
10 equal to LMP, so any payments would be LMP-LMP or zero. Thus offering such programs  
11 to customers facing dynamic pricing is inappropriate.

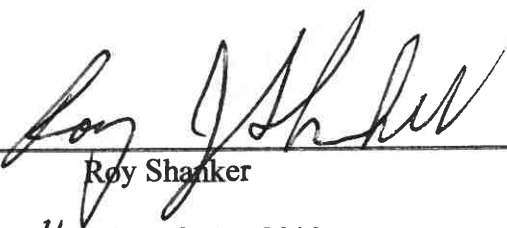
12 62) This concludes my affidavit.

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

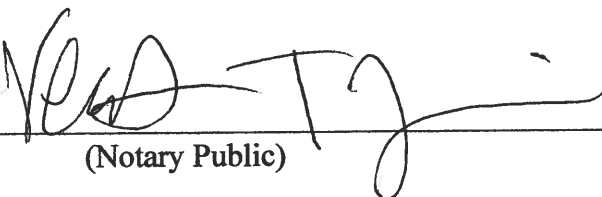
Demand Response Compensation  
in Organized Wholesale Energy Markets

)  
) Docket No. RM10-17-000

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing Affidavit regarding the Energy Market Demand Response NOPR on behalf of the New England Power Generators Association is true, correct, accurate and complete to the best of my knowledge, information, and belief.

  
\_\_\_\_\_  
Roy Shanker

SUBSCRIBED AND SWORN to before me this 11 day of May 2010.

  
\_\_\_\_\_  
(Notary Public)

My commission expires: \_\_\_\_\_

VENUS TUVIN  
NOTARY PUBLIC  
MONTGOMERY COUNTY  
MARYLAND  
MY COMMISSION EXPIRES NOV. 13, 2010

**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 - Independent Consultant  
Present 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:

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 Association, 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 consortium 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 of the 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 Capacity credits.

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. Affidavit 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 Capacity within 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, 15<sup>th</sup> Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limited 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 application 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 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.

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. Affidavit 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.

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