UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Compensation for Generating Units Subject to Local Market Power Mitigation In Bid-based Markets	Docket No. PL04-2-000

Post-Technical Conference Comments of The Electricity Consumers Resource Council (ELCON)

Dated: February 27, 2004

The Electricity Consumers Resource Council (ELCON) appreciates the opportunity to submit comments on how to compensate generating units subject to local market power mitigation. This issue and other efforts to administratively-impose capacity markets have been nagging problems in the industry since the early days of restructuring in the United Kingdom, California and elsewhere. The Commission's attention to this matter is long overdue and greatly appreciated. Our recommendations are in the form of a comprehensive reappraisal of the pricing mechanisms to ensure that well-functioning competitive wholesale markets are indeed allowed to operate in both organized and bilateral markets. We do this because the problems are related and deserve a common set of solutions.

ELCON's perspective on these issues is derived from the geographic and multi-national characteristics of its membership. The typical ELCON member operates major manufacturing facilities in several different electricity markets in the U.S. and abroad. It is not uncommon, for example, for a member to have operations in California, Texas, Mississippi, and as many or more offshore locations. Understandably, ELCON members seek reasonably common electricity market designs based on their experience in other global commodity markets.

The problem posed in this docket results from the fact that when regional electricity markets were restructured with a combination of generation divestiture, retail access and the establishment of independent system operators with operational control of most transmission assets, it was not fully appreciated that some generators retained significant local market power due to concentrated ownership in load pockets or that some units were required for reliable operation of the transmission system. The combination of these factors is even more significant. The situation was further exacerbated where market-based rate authority was granted to entities under the assumption that the OATT would sufficiently mitigate market power. The same assumption applied to new owners without regard to the fact that some units were required for reliable transmission operation. In many cases the new owners paid substantial acquisition premia (*e.g.*, goodwill) for their investments. An early assumption in the restructuring debate was that generation was no longer a natural monopoly and that generation-on-generation competition was not only feasible but desirable. In hindsight, that is still generally true, but not always true.[1]

The problem of local market power is not limited to regions that attempted to restructure and now operate bid-based markets. It is also endemic to other regions where states do little to promote competitive wholesale or retail markets but allow and even encourage jurisdictional utilities to take advantage of regional markets in ways that do not promote the synergies of

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[1] The "post-1996" problem—the erroneous assumption that new independent generators could not exercise market power—is a symptom of this fact.

competition.[2] In these regions, vertically integrated utilities own and operate "pivotal" generators that are price-makers in a significant number of hours.[3] These generators are generally uncommitted rate-based generators that are authorized to sell electricity in the wholesale market at market-based rates.

In organized markets (*i.e.,* centralized markets that are operated under security constrained, bid-based, economic dispatch with nodal prices), the ISO or RTO cannot dispatch generators with both local market power and market-based rate authorization without distorting market outcomes with harm to reliability, consumer welfare or both. Some form of out-of-market intervention may be necessary to accommodate this non-market condition.

The extreme cases, reliability must-run or RMR generators, are the pivotal—price-setting—suppliers in load pockets that result from inadequate transmission resources. This also may not be a scarcity problem (*i.e.*, inadequate generation) but an ownership concentration problem in which too much generation in the local market is owned or controlled by a single company. The reasons for the transmission inadequacy are many and varied, and may include past decisions by the transmission owner that were prudent, such as building generation in the pocket because it was the "least-cost" alternative under a cost-of-service regime, or imprudent because the utility deliberately under-built transmission to preserve its generation market power in anticipation of industry-wide restructuring.

Compensation schemes for RMR generators have been problematic because some companies in the unregulated generation sector are in dire financial trouble for reasons largely of

[2] *See* Comments of the Electricity Consumers Resource Council, Docket No. PL02-8-000 *et al.* ("Conference on Supply Margin Assessment"), January 6, 2004

[3] Seventy-four entities have failed the SMA screen. *See* Transcript of Technical Conference on Supply Margin Assessment, January 13, 2004, page 234.

their own making. In many regions of the country new natural gas-fired generation has been overbuilt at the same time that many companies engaged in an acquisition binge. From a consumer perspective, this is a pathetic repetition of the “when will the lights go out” scenarios of the 1980s when utilities overbuilt nuclear capacity and threatened financial ruin if they did not get significant new rate increases or, better still, a government bailout. While an important reason for deregulating generation in the past decade has been to avoid a repetition of what has been called the stranded cost problem, electric consumers served in organized markets are increasingly being confronted with new “your money or your lights” threats. The wild claims for RMR compensation is but the most egregious of such threats.

The following recommendations address compensation for generation with local market power in the context of a more comprehensive reappraisal of the pricing mechanisms in both organized and bilateral markets. We believe that fixing RMR compensation cannot be done in isolation of other generic problems related to capacity markets and market design in general. We offer these recommendations with the intent to ensure that well-functioning competitive markets are indeed established and allowed to operate.

Recommendations

1. **Complete the Organized Markets.** We urge the Commission to return to basics and establish as its number one priority the creation of more complete markets. Proposed or existing market designs in the Northeast, Midwest and California consist of a mixture of competitive and pivotal generators on the supply side and highly inelastic demand on the demand side. This is an incomplete market that is easily gamed and fraught with other problems. The Commission and the ISOs and RTOs are now consumed with trying to jury-

rig structural fixes to these problems—and in the process they are creating very complex and convoluted market mechanisms that are making competitive markets such a difficult sell in the South and West. The Commission should redirect its efforts and insist that existing organized markets are reconstituted as complete markets as expeditiously as possible. Such markets will more efficiently mitigate price risk by making forward contracting and other risk management practices more effective. The essential elements of a complete market that are missing from today's organized markets are described in our remaining recommendations.

2. **Create Organized Markets for Demand Response.** A fundamental requirement of complete markets is markets for demand response. Demand response is essential to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers. Progress has been made with some ISO/RTO sponsored demand response programs but these successes only demonstrate the efficacy of the concept. Implementation of real markets—not regulatory era programs—has been held hostage to ISO/RTO stakeholder processes that are dominated by supply-side interests who oppose competition from the demand side.

When fully consummated, markets for demand response will make it difficult for gaming strategies such as "hockey stick" bidding to exploit the inelastic demand of incomplete organized markets and bring about generator bids at levels closer to marginal cost as intended by theory. Demand response bids contribute an essential market dynamic to the extent that demand bids reveal the value of lost load (VOLL) at any given hour in the marketplace and therefore deserve the right to compete on a kWh to kWh basis with supply bids.

The requirements of an organized market for demand response is relatively simple to implement. Demand response as a resource must have equal and symmetrical rights of access to all ISO/RTO energy and capacity markets (including ancillary services) that are open to any other competitive resource such as generation resources. If a competitive bulk power market is the desired end-state of the Commission's policy, price-responsive load must have non-discriminatory access to any and all markets (bid-based or otherwise) that are available to other resources.

Demand response as a resource will also not happen unless customers with price-responsive loads are compensated on the same basis as any generator.[4] Customers must not be forced to "split the savings" with intermediaries (*e.g.*, LSEs) as a pre-condition to access to any demand response market. The compensation issue must be established as a matter of Commission policy (*e.g.,* made part of the OATT) to avoid the need to further fight this matter separately in every biased ISO or RTO stakeholder process and ultimately in every ISO or RTO tariff proceeding. The mechanics of price determination for any resource should be the same for both supply and demand resources, *i.e.*, the price at the margin for a unit decrement of demand response must be calculated in the same manner as the price for a unit increment of supply. The prices must not be the result of two separate protocols, procedures or software packages.

We urge the Commission to be very wary of delegating the responsibility for developing markets for demand response to ISO/RTO stakeholder processes as currently

[4] Additional investments in real-time metering and telemetry by price-responsive customers who do not already have such equipment will only materialize after the requisite markets are in place and the customers have confidence that the market work.

constituted because they are all dominated by supply-side market participants whose market power (or jurisdiction in the case of public power) is eroded by demand response.

3. **Implement the Interim Supply Margin Assessment Screen**. The problem of local market power does not just exist in load pockets in regions with organized markets. The Commission has determined that at least 74 generators are pivotal at different times and therefore capable of setting the price in the local markets in which they operate or influence. Even if the SMA screen is partially flawed, and perhaps only half of those generators are really pivotal to the point of being a serious problem, that is still a huge concern. It is preferable to implement the SMA and then have the applicant demonstrate that it does not have market power, rather than assume that the OATT is sufficient to mitigate market power. As noted in our January 6, 2004 SMA comments, SMA screening should err on the side of triggering too many failures rather than too few because cost-based mitigation is a hold-harmless backstop from the perspective of retail customers.[5]

We urge the Commission to follow through on its commitment to finalize an interim generation market power screen and mitigation measures applicable to entities that fail the screen, and proceed with its pending review of new methods for analyzing market power. Removing the uncertainty associated with delaying such actions will send an important signal to market participants and investors that the markets are worthy of their confidence.

4. **Eliminate All ICAP-like and Artificial Capacity Pricing Mechanisms.** Mandatory capacity markets are unnatural in competitive markets—no other competitive commodity market sanctions such a multiple-dimensional pricing structure that allows the basic

[5] Electricity Consumers Resource Council, *Op. Cit.*, Page 5

physical commodity to be sold multiple times.[6] We are not convinced that electricity is so different as to require such a radical departure from fundamental market principles particularly in states that allow some form of retail access.[7] Unlike cost-of-service ratemaking, in which separate demand and energy charges play a meaningful regulatory accounting function, the mechanism for fixed cost recovery in a competitive market framework should be in the hourly commodity (energy) prices. There is no need for a separate demand charge in the commodity price.[8]

Capacity markets distort an otherwise workable competitive energy-only market for the following reasons. First, the markets are easily gamed and do not work. For example, in England and Wales, the predictability of administratively-set capacity payments led to gaming and manipulation of the payments, and market distortions that spilled over into the natural gas markets .[9] The scheme was subsequently abandoned *in toto* and the market is now working just fine. Second, the markets are overly generous to incumbent generators (primarily incumbent utility owners of coal-fired or nuclear generation) who have little intention to expand their portfolios in the region. No public policy is served by giving these generators a subsidy especially since many were already beneficiaries of state stranded cost guarantees. Third, capacity markets provide a direct subsidy to only physical assets and

[6] Options on the productive capacity of assets such as airplanes, automobile fleets (by rental car companies) or other durable goods are routinely transacted in private markets but are voluntary and the costs are not imposed on marketers or end-use customers in the form of a price adder. For example, airlines do not add a "demand charge" to airline tickets because they hold options with Boeing or Airbus for the future delivery of airplanes.

[7] In fact, we are quite suspicious of such claims because it is always a prelude to arguments for higher retail rates or "prices." The truly unique feature of electricity markets is the constant threat of local market power that requires prospective mitigation.

[8] We support the continuation of capacity-related products that are currently defined as ancillary services.

[9] *See* Morgan Stanley Capital Group Inc., Motion to Intevene and Protest, Docket No. ER03-647-000 ("New York Independent System Operator, Inc."), April 11, 2003, page 6. Also, *see*, Shmuel S. Oren, "Ensuring Generation Adequacy in Competitive Electricity Markets, " UC Energy Institute, June 2003.

therefore discriminates against financial market participants.[10] Finally, to the extent such markets are imposed before organized markets are in a more complete state (*e.g.,* markets for demand response are created), the payments are discriminatory to other physical market participants.

5. **Impose RMR Unit Divestiture Moratorium.** We recommend that a moratorium be imposed on any future divestiture (from traditional rate bases) of potential RMR generating units. This recommendation would apply to units whose generation is predominantly must-run and not units that are in-market most hours. This recommendation may be moot as regions of the country that have yet to restructure their electric sectors are well aware of the RMR (and other) problems in regions with organized markets. If, by definition, RMR units were originally built as economic substitutes for traditional transmission assets, then RMR units should be re-functionalized as transmission assets and remain rate-based subject to cost-of-service ratemaking treatment. As new organized markets emerge, the units' non-must-run output could be bid-in at variable cost or simply take the LMP at its node by submitting a zero bid.

It is normal and desirable to mix within any modern economy a combination of regulated and private markets in recognition of the existence of both public and private goods. Network transmission assets and any economic substitutes for such assets provide services that are public goods, and pivotal RMR generating units fall in that category because of significant and often binding entry barriers.[11]

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[10] Morgan Stanley Capital Group Inc., *Op. Cit.*, page 7

[11] RMR generation may remain the preferred (or only) resource option in some load pockets because of binding legal and environmental obstacles. Ideally, independent transmission companies (ITCs) would build and

The moratorium on RMR unit divestiture should not continue indefinitely. We recommend that RMR unit divestitures be considered on a case-by-case basis after one or two cycles of the applicable RTO's planning cycle have been completed (*i.e.*, new transmission or other investments intended to mitigate the deleterious effects of the load pocket are planned, perhaps subject to an auction, and completed).

6. **Fixed Cost Recovery of RMR Units.** In regions of the country where RMR generating units were divested with acquisition premia, we recommend that the Commission continue its policy established in *Duke Energy Moss Landing* that strictly limits recovery of any such premia in RMR contracts.[12] In response to proposed RMR contracts in California, the Commission summarily dismissed Duke Energy Moss Landing's proposed rate recovery of an acquisition adjustment.[13] In rejecting Duke Energy Moss Landing's request, the Commission emphasized:

> Allowing the acquisition premium to be used in determining rates in non-competitive market conditions (*i.e.*, must-run conditions) would lessen the discipline on the prices offered for assets from which such cost-based sales would be made. Potential buyers would have incentives to pay inflated prices for such assets, knowing they could recoup their costs from customers with limited or no choices.[14]

RMR units serving load pockets are often a substitute for transmission service and are essentially a public good (reliability). This is not a service derived from normal

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own RMR generating units or outsource these resources, but in any case, these resources would be compensated under multi-year cost of service contracts.

[12] Duke Energy Moss Landing, LLC, 86 FERC ¶ 61,227 (1999) (rejecting request for approval of an acquisition adjustment where petitioners paid $180 million more than the net of the facility's book value).

[13] Frank Wolak's arguments against recovery of acquisition premium is stated well in his written comments ("Consumers should pay for stranded assets only once.") *See* Frank A. Wolak, Comments for Technical Conference on Compensation for Generation Units Subject to Local Market Power Mitigation in Bid-Based Markets, FERC Docket Nos. PL04-2-000 *et al*., February 5, 2004.

[14] Id.

resource scarcity—or that is otherwise a private good—that would benefit from locational price signals. Arguments for RMR compensation schemes that would "send locational price signals" for a public good are silly. The whereabouts of load pockets are no mystery and the appropriate long-term solution is the independent RTO planning process and adequate transmission and demand response resources to decrease reliance on one or a few generating units.[15] The continued proliferation of locational prices also does not make economic sense as long as demand is inelastic and there are no organized markets for demand response.

The prospective out-of-market solution for RMR compensation should depend on how frequent a generator's must-run or pivotal status is relative to its capacity factor. If the unit is must-run or pivotal relatively infrequently, it should only receive its variable cost—for the pivotal quantity—during those hours requiring mitigation or the market clearing price at its node. It will have ample opportunity to recover its fixed costs during in-market hours. If the unit is must-run or pivotal most of the time, or for a period of time such that compensation based on variable costs or the LMPs substantially under-recovers fixed costs, the generator may petition the RTO for a long-term cost of service contract for subsequent FERC approval and contingent on the *Moss Landing* precedent. They should auction off the asset(s) if they are unwilling to do this.

The Commission is urged not to distort the bulk of the generation market that is workably competitive by attempting to force a market solution to a portion of it that may

[15] The proposal by PJM (Docket No. EL03-236-000) for an auction to deal with the long-term mitigation of local market power has merit and should be tested on a limited basis. The RTO would select the lowest cost option from among the bidders of new transmission, generation and demand response. However, there must be a more compelling case that scarcity is the true problem and not ownership concentration, and that such scarcity has profound reliability implications unless mitigated.

never be competitive. The tail must not wag the dog, *i.e.*, forcing a market solution on RMR generation must not be used as an excuse to distort the entire market for generation.

7. **LMP Treatment of Bids by Generators With Local Market Power.** There is no question that the bids of pivotal generating units must be subject to some form of mitigation. We are concerned that including mitigated bids in the LMP calculations creates incentives for firms owning portfolios of generating units to bid or schedule their units to increase the likelihood that units with local market power will set higher prices for all units. For example, if the mitigated bid is $50/MWh, the portfolio-owning firm will set the bids of all of its units (locally or outside the pocket) at a minimum of $50. To the extent that other generating companies are aware of the mitigated bid, they too will use that bid as a floor for their bids because they know that the $50 bid in the pocket must be accepted and will be used to set the LMPs. The effect of this is to spread the market power problem to customers outside the load pocket.

We recommend that the Commission eliminate any such incentives that a generating firm has to leverage the local market power possessed by some of its units into greater market power exercised by all of its units. Rather than running the LMP algorithm with this unit's mitigated bid in place of its actual bid, the ISO or RTO should treat this unit as a price-taker for this quantity of energy in its day-ahead price-setting process by bidding zero. This unit would be unable to set or influence the market price at any location using its mitigated bids, and would be offered the option to receive either its allowed RMR payment or the LMP for all of the energy it provides. The RTO would continue to guarantee that if a unit remains under must-run conditions it is guaranteed to recover its start-up, no-load, and variable operating costs.

8. **Eliminate Exit Barriers of Unregulated Generators.** A primary benefit of electric industry restructuring was the promise that inefficient market participants would exit the market without burdening end-use consumers with their stranded costs. Generator proposals for RMR contracts and various variations of capacity markets (other than for ancillary services) constitute an unwarranted life-support system for generation owners who should probably exit the market. The proposals also guarantee monopoly profits for the other generators. Consumers are being cheated by the fact that the assets of some of these companies have not been liquidated and allowed to exert downward pressure on generation fixed costs. This is a normal, healthy dynamic of competitive markets.

We also strongly agree with CAISO Market Surveillance Committee Chair, Frank Wolak, in his remarks during the February 4-5 Technical Conference, that a RMR unit needed for reliability should be able to recover costs sufficiently to keep the unit in operation at that location, but not the recovery necessary to keep the owner of that unit at that location. The RMR or pivotal supplier problems are often created by ownership concentration in the load pocket and not by scarcity of generation.

9. **Relax Bid Caps.** One of the first administrative impositions to distort the competitive energy market platform advanced by FERC was the bid cap. The Commission's current policy imposes a $1,000 per MWh cap in all bid-based energy markets except California where it is somewhat lower. The caps have been useful for restraining the ability of some generators to exercise market power during the ongoing process of finding the right market rules. Nonetheless such caps also tend to disguise true resource scarcity. The end state of a competitive electric energy market—and it should abide by the economic norms of other commodity markets—should not have such caps—or floors. But how and when to relax

these caps that now seem to be a permanent fixture of existing markets is not so simple. We recommend that the Commission may consider the need to gradually increase the caps for the stated purpose of allowing true scarcity pricing to function in the marketplace provided that (1) organized markets for demand response have been established and proven, (2) new, local market power mitigation measures are in place and working, (3) each organized market has an independent market monitor, and (4) the Commission no longer grants market-based rate authority to entities exceeding DOJ standards for HHI.

10. **Long-term Resource Adequacy.** In a competitive market, resource adequacy is a private good that should be left to the market provided that the markets are complete, workably competitive, and the risk of regulatory impositions or market intervention is minimal. Retail access should allow end-use consumers and load serving entities (LSEs) to select the price risk associated with the service that best meets their needs.

The few states that are not awash in excess capacity and are concerned that the market will not ensure long-run resource adequacy should offer loan guarantees, tax abatements or other direct subsidies to generators to locate new capacity within the state borders and localize those costs to the taxpayers in those states (*i.e.*, funded through the state government's general revenues). This is not unlike incentives offered to manufacturers to locate new facilities in such states to create new jobs or retain old jobs. This is preferable to allowing multi-state regional markets to be distorted by imposing regulatory incentives such as mandatory capacity charges on consumers with no guarantee that the subsidies these charges provide to generators will result in any new investments.

A major shortcoming of existing organized markets is the lack of forward contracting that does not require the buyer to pay an excessive premium and force a short position. This may result from the fact that generators are not exposed to enough price risk to encourage them to negotiate long-term contracts. This is a real economic barrier to new investments, now and in the future, as long as this barrier exists. FERC should remove disincentives to forward contracting and, for the purpose of ensuring that new investments are in lockstep with growing demand, encourage "time-proven" financing by means of bilateral contracts. Frank Napolitano, Manager and co-head, Lehman Global Power Group, referred to such contracting as "Regime B (PURPA Contracted Power Project Regime)."[16] He also said:

> The employment of a similar financing mechanism at this sensitive point in time with respect to the infrastructure …, we believe, would be extremely well received by infrastructure investors.

Respectfully submitted,

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[16] Page 21, February 4th Transcript.