

Problems in the Organized Markets



A Special Report of the Electricity Consumers Resource Council





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The most successful wholesale electricity markets, as judged by the competitiveness of their spot markets, are those with where only a very small fraction of the total amount of electricity consumed is actually purchased in the spot market.

Frank A. Wolak

Introduction

ELCON was an early supporter of a competitive electricity market and perhaps its strongest proponent. We still today unequivocally believe that real competition in electricity will bring real benefits to all consumers and promote a healthy, growing US economy. But the implementation of such markets must be done right and thus far this has not happened. The main reasons this has not happened are (1) the existing transmission infrastructure will not support a competitive wholesale market that fairly balances the interests of consumers and suppliers, (2) a market design based on nodal pricing is ill suited to a constrained transmission network given that the current owners and operators of the transmission system either do not or cannot relieve the constraints, and (3) the absence of coordinated federal-state policies for ensuring that incremental transmission investments are undertaken.

The current state of the markets is substantially different from the relatively simple locational marginal pricing (LMP) or nodal pricing scheme that was promoted earlier in the restructuring debates. The Organized Markets that have actually emerged—of

which PJM is often touted as the most successful example—are not markets in which supply (generators) and demand (customers) interact to set market clearing prices. The Organized Markets have no self-regulating capability to achieve efficient pricing outcomes because the markets as a whole are illiquid. What has emerged is a contrived, hybrid market with final prices paid by consumers set by a complex combination of short-term auctions (with supplier only offers) and regulatory ratemaking.¹

This Special Report reviews the needs of large industrial consumers in domestic electricity markets, and their concerns and frustrations with the progress to date in restructuring wholesale electricity markets. It describes the need to recognize certain market fundamentals as preconditions to achieving a truly competitive wholesale market that ELCON has long advocated. However, it has become obvious that America’s existing transmission infrastructure impedes a competitive regime and that further efforts to encourage other Organized Markets should be suspended until it is resolved that the public is willing to support the siting of new investments, how transmission upgrades are funded, and equal access to the grid for all generation is assured so that material benefits of competition are realizable for end-use customers.

This report concludes with a series of recommendations urging FERC to thoroughly investigate the impediments to new transmission investments and the structural problems of the Organized Markets that are impeding true competition and denying end-use consumers rightful benefits of competitive wholesale markets.

The Electricity Supply Needs of Large End Users

A series of FERC initiatives including Order No. 888, Order No. 2000, and subsequent orders on implementation, were promulgated to put in place “the foundation necessary for competitive wholesale power markets.” In 1999 FERC recognized in defending its proposed rule on RTOs that the traditional industry structure was “depriving the Nation of the benefits of lower prices and enhanced reliability.” ELCON was a strong proponent of these FERC initiatives.

Original Expectations of Large End Users

¹ The features of the Organized Markets are somewhat in flux and evolving but, in general, include the following: bid-based, security-constrained, economic dispatch with locational (nodal) prices; financial transmission rights; day-ahead and real-time markets with offer caps in lieu of price-responsive load, and a multi-settlement system; automatic price mitigation; and locational installed capacity market with administratively determined price levels. The current Organized Markets are PJM, the Midwest ISO, the New York ISO, and ISO New England.

Large industrial customers expected that competitive markets would bring: (1) an energy commodity market with the “look and feel” of other competitive markets; (2) a customer focus and product differentiation; (3) an efficient trading continuum from the forward market down to real-time balancing; (4) technological and marketing innovation; (5) symmetrical treatment of price-responsive loads with generators and therefore fully functioning, bilateral and spot markets with prices set by competition between generators and loads; (6) a self-regulating market structure that minimizes the need for regulatory intervention to mitigate market power; and (7) unregulated generators assuming and managing all the risk of their investment decisions.

Unfortunately, the markets that have emerged fail to fulfill these expectations. Specific design features of the Organized Markets, increased congestion, and growing generator concentration, especially among utilities that also own transmission, have hampered the development of truly competitive markets.

The Benefits of Forward Markets

Competitive liquid forward markets provide information on long-term supply and demand conditions, decrease spot market prices, and support long-term investment decisions.

Forward markets allow a variety of contracts, as well as contract terms and conditions, tailored to the specific needs of individual customers. In a market dependent on forward contracting, there is no presumption that all customers want the same physical or financial products, and thus the market orientation becomes *customer focused* and *customer driven*. Customers are free to negotiate prices, terms and conditions, risk management, and other services that meet their commercial or individual needs. Suppliers are free—and many are willing—to offer innovative and different products and services to individual customers or aggregated customers. Independent power exchanges operate external to the real-time balancing function to allow for the trading of contracts and scheduling and to provide price transparency.

Long-term bilateral contracts in a robust, liquid forward market also provide the steady cash flow that is essential for ensuring timely, new investment in the industry. It was assumed that a competitive market would exhibit boom-bust investment cycles because every capital-intensive industry has this characteristic (as did the state-regulated utility industry). A forward market provides buyer protection from the extremes of this phenomenon commensurate with each buyer’s price risk tolerance.

Forward contracts and hedges can limit exposure to spot prices and price volatility. It was anticipated that local distribution companies (LDCs), load-serving entities (LSEs), and new retail service companies would be major users of forward contracts to minimize their exposure to pricing volatility. Likewise, many large industrial customers prefer to budget their energy procurement requirements, often several years in advance.

Problems in the Organized Markets

The Organized Markets that are currently operated by FERC-approved ISOs and RTOs are increasingly diverging from the fundamentals of a true competitive market. This is clearly indicated by the fact that the transaction volumes in the spot markets are rapidly growing as legacy contracts expire. In PJM, for example, Real-Time Spot Market activity averaged 40% of average loads for all hours in 2003. In 1999, it was only 15%.²

The Organized Markets are not effective platforms for wholesale competition because of the combination of generator concentration, the innate illiquidity of nodal markets, and the introduction of a capacity market that is subject to “price” determination in an adversarial, administrative process. As long as RTOs cannot or do not compel the construction of new transmission facilities that mitigates congestion, this combination of factors provides the large utility holding companies with no economic incentive to negotiate long-term contracts or invest in new transmission that would reduce spot market prices and/or weaken their market power.

In the Organized Markets of the Northeast, natural gas-fired units are increasingly on the margin. Some of these units are also part of fleets of generators that include nuclear and/or coal-fired units. The owners of nuclear and coal-fired generators know that these units will not be the marginal unit and therefore submit bids that guarantee dispatch—and maximize the infra-marginal revenues. These generators get the LMPs set by natural gas prices. While it is generally true in competitive markets that the marginal supplier sets the market-clearing price, the conditions that make such markets mutually beneficial to both suppliers and consumers are absent from the Organized Markets. Without Demand Response—that has the potential to push the highest cost fuels off the margin—and the mitigation of the local market power of dominant generators, the pricing outcomes of the Organized Markets can be very punitive to consumers, large and small.

² PJM Market Monitoring Unit, 2003 State of the Market (March 4, 2004), p.17; 1999 State of the Market Report (June 2000), p. 2.

Other factors also work against the interests of consumers. The introduction of an artificial capacity market with locational installed capacity (LICAP) payments has shifted generator investment risk back to the consumer. These out-of-market payments discourage generators from seeking fixed cost recovery in bilateral contracts. Many owners of generators arguably are receiving more than just a reasonable opportunity to recover their investments. No wonder these suppliers are strongly in opposition to any risk that their authority to sell at market-based rates is jeopardized.

While the old industry was considered reliable and generally met the 1-outage-in-10-years reliability standard, it provided few choices, and most often forced the consumer to adapt to its product, and not the other way around. It was the greatest hope of

Factors That Prevent the Formation of Forward Markets

- Infra-marginal Revenues & Guaranteed Capacity Payments
- Illiquidity in Locational Markets
- Short-term Only Financial Transmission Rights (FTRs)
- Failure of FTRs to Incent Congestion Mitigation
- Joint Ownership of Generation & Transmission

ELCON members that this would change under federal policies to promote wholesale electricity markets that complemented state restructuring efforts. But this beneficial change has not materialized. ELCON members with facilities in the Organized Markets believe that these wholesale markets have not delivered promised benefits to end-use customers. As a matter of national policy, and at a time when manufacturing jobs are fleeing the high costs of U.S. operations, the basic design of the Organized Markets needs serious reconsideration and the effort to establish real competitive wholesale markets a new direction.

The Illiquidity of Locational Pricing

The locational pricing feature of the Organized Markets unnecessarily fragments the market, which sacrifices two important sources of efficiencies.

First, locational pricing of a transmission network with chronic congestion is likely to produce illiquid markets that greatly magnify the potential exercise of local market power by pivotal suppliers—suppliers that can exercise such market power to leverage

their ownership of nuclear or coal-fired generators. The transmission constraints generally free these local suppliers from competition by distant generators, and the absence of Demand Response gives the local suppliers both a captive market and an easily forecasted load.

Second, the logical extension of locational pricing with a federally mandated resource adequacy requirement is to force resource adequacy all the way down to the nodal level. This greatly sacrifices the benefits of scale and scope economies of the electric industry—benefits that any properly restructured market would wisely preserve.

Financial Transmission Rights & Incentives for New Investments

Locational pricing was created to provide economic incentives to initiate new (“merchant”) transmission investments. Central to the theory was the creation of point-to-point financial transmission rights (FTRs). FTRs are property rights that a merchant investor receives entitling that investor to the congestion revenues associated with the new asset. The revenues establish the economic incentive for the investment and are intended to recover capital and operating costs.

However, as practiced, the theory does not result in the mitigation of congestion. Consumers are required to pay congestion costs that continue to rise at alarming rates. In at least two Organized Markets annual congestion costs are now nearly \$1 billion. The congestion risk of locational pricing was sold based on the hedge value of FTRs. However, local market power, allocation problems, imperfections in the underlying theory, the absence of long-term FTRs, and the fact that most owners of generator fleets benefit from congestion, and therefore have no incentive to remove it, make the FTR construct another costly burden for consumers with no obvious countervailing benefits to justify it.

The problem with FTRs (and LMP in general) is not so much that it fails to incent new investment as promised, but that it opens up a Pandora’s Box of “beggar thy neighbor” proposals for shifting costs from one stakeholder group to another. One must question the benefits of sending so-called price signals for monopoly services if it only focuses attention away from planning new investments and becomes a disguised form of cost shifting. Proposals for Participant Funding are one such example. Every vertically integrated transmission owner is thinking, “Why should I build when the costs can be shifted on to someone else.”

The existing transmission infrastructure was planned based on the fact that generation and transmission were economic substitutes and, as such, generators were often sited in

load pockets with regulatory approval in lieu of building new transmission facilities. The costs were socialized across all ratepayers in the form of an uplift based on average costs. This tradeoff of generation and transmission was not fully appreciated in the choice of locational pricing as the foundation of Organized Markets or by states that mandated generation divestiture as a component of their policy on stranded cost recovery.

Part of this problem is the failure to recognize that generators that were or are built as a substitute for transmission should, in fact, be treated like any other transmission facility and not as merchant power plants producing a commodity. Such generators are

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essential facilities that should be subject to traditional rate regulation and refunctionalized as transmission facilities.³ Instead, the trend in the Organized Markets is to assume that markets for monopoly services can or should be achieved and thus the owners of these *de facto* transmission facilities seek compensation based on the higher of cost of service or the opportunity costs of any potential commodity energy sale.

It is not self-evident that the market model based on LMPs and FTRs is superior in practice than a model based on physical rights. Thus, there needs to be a very serious reconsideration of this means of “managing” congestion. The planning and construction of the underlying infrastructure presumed that the costs associated with those tradeoffs would be socialized in average rates, and it worked. The congestion management regime of Organized Markets makes little sense to consumers—and wrongfully punishes those unlucky enough to be in a constrained location—given the failure of this model to encourage new investments and the absence of other offsetting benefits. A clear benefit of abandoning this requirement and restoring a system in which all

³ The nodal pricing model does not resolve the dichotomy of a generating asset with two mutually incompatible commercial roles, one role as a merchant generation and a second role as a monopoly transmission supporting facility, for the very reason that monopoly services cannot be priced at what the market will bear.

consumers share the common costs of building and operating the transmission network would seem to be added market liquidity in a forward market.

Market Intervention & Re-Regulation

Since the ISOs and RTOs began operations, their markets are slowly being re-regulated as a result of the innate features of locational pricing and the local market power of large owners of generation. The net result of these actions is to shift more market risk back to consumers and clearly this was not the intent of industry restructuring.

ELCON has opposed a market design based on LMP since it entered public debate in California in the mid-1990s. The skepticism was not that bid-based markets would not work under the right circumstances, but that regulators would never leave these markets alone. Rather, they would encumber such markets with operational “patches” and regulatory “fixes,” given that pricing transparency and bidding behavior decidedly favored the suppliers, and retail loads would never have access to the markets on an equal footing with suppliers. The need of large industrial consumers—and arguably all consumers—was a market based on longer term, bilateral contracts, not an all-embracing spot market.

Such fears have since been borne out. First, price (“offer”) caps were mandated to restrain pricing volatility that was inevitable with any short-term auction market for an energy commodity. Next, Automatic Mitigation Procedures (AMP) were added to address the exercise of system-wide or local market power concerns. AMP, as practiced, includes conduct thresholds that may give generators some discretion to increase prices without actually triggering mitigation. Another example of re-regulation is the creation of an artificial market for capacity—in its latest form the so-called locational installed capacity (LICAP) mechanism. While labeled a “market,” the price levels are actually adjudicated in hotly contested regulatory proceedings. And still another layer of interference is likely pending in a FERC staff proposal on reactive power.

Electricity Prices: Higher Than Cost-of-Service Rates by Design, Not by the Market

The market that is emerging is a contrived, hybrid market with final prices paid by consumers set by a complex combination of short-term auctions (with supplier-only offers) and regulatory ratemaking. The net effect is one with increasing prices for consumers, prices that now generally exceed cost-based rates.⁴ There is little that has

⁴ Past federal and state policies on stranded cost recovery assumed that market prices would be lower than regulated rates, and that generation owners would be unable to recover their fixed costs in such markets. With the benefit of hindsight it is clear that this has not been the case. As

been accomplished by the Organized Markets that has exerted any discernable downward pressure on prices. Consumers no longer benefit from the low marginal costs of coal-fired or nuclear generation because LMPs with no inter-fuel competition or Demand Response routinely exceed the short-run marginal costs of these generators. Capacity payments can be pocketed even if the units subsequently produce energy and receive the LMPs that likely will include an additional contribution to fixed costs. And many generators continue to benefit from additional revenue streams that are available in retail rates. The economic premium thus created for generators in short term markets is the main disincentive to essential forward contracting in the market.

Most regions of the country have a surplus of generation. Some of the new generation was sited in locations that do not readily accommodate economic dispatch and therefore

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low-cost generation is not being fully utilized. Consequently, congestion costs are rapidly escalating because more units have to be redispatched, *i.e.*, dispatched out of economic merit (lower cost generation replaced by higher cost generation) order. As Enron demonstrated, generators can strategically bid their power in order to secure desired dispatch instructions, and therefore, generator bids will not always be reliable approximations of their marginal production costs. Yet, accurate marginal costs are the underpinnings of a correctly functioning economic dispatch system.

Clearly, the desired outcome of the LMP/FTR construct—to create economic incentives for new investment—is not happening. And all these new costs are being arbitrarily allocated to consumers under the pretense that they—the consumers—caused out-of-merit dispatch.

An overarching objective during the transition to a restructured industry—and assuming that price-responsive load is denied access to the market—is that the sum of the unbundled elements of electric service should be no greater than the bundled price

noted above, many old, formerly rate-based units (*e.g.*, nuclear plants) are given new opportunities to recover fixed costs in markets that deny consumers the benefits of those generators' lower operating costs. Thus, in the transition, suppliers have generally been the beneficiaries of a higher of market or cost policy with all the downside risk shifted to consumers.

under traditional regulation for the same service. Once conditions for true competition have been established, market prices should reflect the interaction between suppliers and the demand side. But in the future competitive market, if the sum of prices of the unbundled elements of electric service is higher than the bundled price, or if market clearing prices exceed rates based on cost of service over the long term, then the promise of competition has failed. The basis for this assumption is the fact that cost of service regulation may capture scale and scope economies of the industry better than unbundled markets.

Preconditions to Competitive Wholesale Markets

1. Regional Transmission Organizations (RTOs) with Non-Discriminatory Stakeholder Processes
2. Energy-Only Commodity Markets
3. Elimination of Entry Barriers to Price-Responsive Loads
4. Market Monitoring & Market Power Mitigation
5. Adequate Transmission Infrastructure
6. Federal-State Regulatory Partnership

Achieving Competitive Wholesale Markets

Preconditions for True Competition

ELCON urges further public debate on the intended outcomes of restructuring and its necessary preconditions. ELCON has long recognized that four factors are essential to the realization of competitive electricity markets. All four factors are within FERC's statutory authority or ability to affect with modest state cooperation. These include: (1) independent RTOs with non-discriminatory stakeholder processes, (2) energy-only markets, (3) elimination of entry barriers to price-responsive loads, and (4) market monitoring and market power mitigation.

Two other factors now also appear necessary. First, new transmission investments are necessary to enable a transmission infra-structure capable of supporting a competitive wholesale market notwithstanding current patterns of generation ownership. Second, the relationship between federal and state regulators is strained, which frustrates cooperation, and this must be corrected.

Precondition 1. Regional Transmission Organizations (RTOs)

ELCON was an early and strong supporter of ISOs and, later, RTOs. An independent grid operator is an essential prerequisite to wholesale competition. As administrator of the tariff and generation interconnection rules, ISOs and RTOs also make it easier for large commercial and industrial companies to pursue generation options without interference from utilities.

Due to political opposition, FERC has probably gone as far as it can with creating new RTOs. The fact that other stakeholder groups share ELCON's concerns with Organized Markets is perhaps the most intractable barrier to further expansion of RTOs to the West and South—or at least until those regions believe that one does not require the other. Nonetheless, some form of independent system operator is necessary to ensure reliable grid operation and support competitive procurement in the wholesale markets.

No existing ISO or RTO is perfect. Yet, there is growing consumer disillusionment with these organizations, especially regarding costs and accountability. If organized correctly, the implementation costs of an ISO or RTO are an investment with an anticipated, long-term payoff. However, imposing the Organized Market structure on every ISO or RTO seems destined to stifle any future efficiencies or other benefits that would justify the costs.

Of equal concern is the role of ISO/RTO stakeholder processes. ELCON has repeatedly raised concerns that if FERC in any way gives deference to the stakeholder process, then that process must be balanced so that one side of the market (suppliers) cannot outvote the other (customers). For example, stakeholder negotiations on Demand Response are often unduly influenced by the fact that market participants who have the most to lose from price-responsive load dominate the stakeholder process. Some of the necessary market preconditions postulated in this report assume such an unbiased stakeholder process. To date, there is no such unbiased stakeholder process among the approved ISOs or RTOs.

Precondition 2. Energy-Only Commodity Market

The only product or service in this industry with sufficient liquidity to be a commodity is energy. This is especially true for the implementation of any nodal or zonal pricing regime in the Organized Markets. Energy-only balancing (spot) markets should be recognized as another primary objective of wholesale restructuring. The purpose of the balancing market is first and foremost to ensure reliability. The balancing market must

be designed to efficiently maintain reliability and not act as an alternative to the forward market.

Precondition 3. Elimination of Entry Barriers to Price-Responsive Loads

A competitive electricity market should offer generation suppliers and price-response loads the opportunity to compete in all markets. Stated another way, price-responsive load should be treated symmetrically with generation and given the same rights of access in the same markets as generation. The markets for Demand Response must be administered by the same entities that administer the market for generation, and not administered by distribution utilities or other intermediaries.

An important value of Demand Response is its potential to push higher cost generation off the margin. It also counteracts the ability of suppliers with local market power to increase prices above competitive levels by reducing congestion.

There is growing concern among industrial consumers that unacceptably high price levels will be necessary to elicit adequate Demand Response given the prevailing levels of generation concentration. This concern is specific to the current situation in which the Organized Markets are increasingly short-term, spot markets. This Catch-22 may be solved if sufficient forward contracting can be achieved. In the traditional regulated industry, much of the Demand Response offered by industrials with this capability was negotiated in bilateral contracts. In this respect the old, regulated industry did a better job than the new.

FERC should use one or more of the existing Organized Markets to test the effectiveness of Demand Response. Certainly many state regulators within the footprint of the Organized Markets are supporters of the RTO concept and the need for a competitive wholesale market to support their retail restructuring efforts. It might have been—and still may be—useful to solicit the cooperation of a limited group of states to at least test the concept. However, the problem of biased stakeholder processes remains, and unless FERC is amenable to reforming stakeholder representation to provide for more balance between the interests of supply and demand (load), FERC is urged to not give deference to RTO stakeholder processes.

Precondition 4. Market Monitoring & Market Power Mitigation

Market monitoring is a critical regulatory function for ensuring efficient market operation. In light of a recent court decision (*EPSA v. FERC*), FERC should carefully reassess the role of market monitors and make sure that they operate consistent with federal law. Part of this reassessment should be wholesale market designs that

minimize the ability of pivotal or dominant suppliers to exercise market power and therefore minimize the scope and cost of market monitoring and market power mitigation or other forms of market intervention.

Since the issuance of Order No. 888 in 1996, rules governing market behavior and market power mitigation were only established as problems emerged and became evident. The crisis provoked, in part, by the California debacle and the collapse of Enron led to a series of initiatives including new tariff rules for market behavior. In 2004, FERC initiated an inquiry on market-based rate (MBR) authority that is intended to produce a more comprehensive, coherent set of rules on market power identification and mitigation. ELCON applauds this effort. But this inquiry should recognize that the growing volume of transactions in the spot markets of PJM and elsewhere and the failure of nodal pricing to incent the mitigation of congestion exacerbate the potential magnitude of system-wide or local market power. This needs to be corrected before new screens and mitigation procedures are developed—otherwise there is the risk of preserving this market imbalance.

Going forward, FERC should be more wary of authorizing MBR than it has in the past. For example, FERC should use its authority to approve MBR to order structural remedies for dominant suppliers by conditioning such approval on new investments that mitigate their local market power. Certainly as market power screens are applied, MBR should be suspended whenever a seller fails any relevant market power test.

ELCON has long argued that sales under cost-of-service tariffs or contracts constitute a fair hold-harmless mitigation policy if a seller is determined to be capable of exercising market power. Given the utility claims that led to generous stranded cost recovery practices in the past, something is seriously wrong with market prices if cost-of-service is no longer deemed fair compensation.

Finally, FERC should demonstrate how prices derived from any non-competitive (*i.e.*, incomplete) markets could be just and reasonable. If they are not just and reasonable, MBR authority should be suspended for any generators or pivotal suppliers that create this market condition. The nascent markets are a long way from a truly competitive end state and the authority to sell at market-based rates should only be approved when it is clear that market power is mitigated and end-use consumers will benefit.

Precondition 5. Adequate Transmission Infrastructure

One outcome of the growing problems in the Organized Markets is a seemingly, open-ended resource adequacy requirement. The Organized Markets rely on the “price

signals” of locational pricing (short-run marginal costs) to trigger the need for and location of new investments without acknowledging the strategic interests of the dominant transmission and generation owners—mostly the incumbent utilities—that may be to prevent such investments. To counter this resistance, attempts are increasingly made to offer additional out-of-market incentives for new transmission investments or the next generation of generators.

New transmission investments are not materializing for at least two reasons. First, transmission investments are being held up because of continued joint ownership of generation and transmission. Shifting the operational control of transmission to the ISO or RTO did little to remove the monopolist’s urge to under build, while it still owned sizable fleets of generators. Second, locational pricing creates a disincentive to relieve congestion if the utility benefits from the congestion. No incentive will work unless it amounts to a buy-through of the expected monopoly revenues.

Stand-alone transmission companies are an ideal solution to this problem but their formation has thus far been extremely limited. There is also little expectation that so-called merchant transmission companies can solve the general under-investment problem. Clearly, state regulators and siting agencies have the responsibility to ensure adequate new transmission investment to conform to any “obligation to serve” under state law.

An additional problem may be the shortcomings of regional planning processes of ISOs and RTOs. ISOs and RTOs do not have stakeholder processes that are free of discrimination, *i.e.*, where one side of the market is over-represented in the stakeholder process, those market participants can easily manipulate the planning process to their advantage. Thus the needs of the under-represented stakeholders are not considered in the planning process. There also may not be sufficient ISO/RTO staff accountability to the independent boards to ensure the integrity of the planning process, and this may require a change in the board structure or the terms of service of board members.

Putting aside the need for new generation, mechanisms such as LICAP fly in the face of economic reason. Long-term investment decisions are widely recognized as being based on expectations of future revenue streams derived from the security of negotiated long-term contracts, not some artificial regulatory device that can change on a moment’s notice. Even investments in the old industry were a form of this practice: the rate-basing of a new generator whose need was prudently determined can be deemed a negotiated long-term contract between ratepayers and utility subject to state regulatory oversight. As long as out-of-market capacity payments are guaranteed to generators, those same

generators and potential counter parties have little incentive to negotiate fixed cost recovery by means of bilateral contracts.

Related to the generation resource adequacy issue is the claim that short-run marginal costs (*i.e.*, locational prices) sends signals for new generation investment. This is not the role of a spot market. Unlike a long-term forward contract, spot market prices do not reveal expectations of the future. In this industry the spot market should serve a balancing (*i.e.*, reliability) function. Pricing signals for new investments in capital-intensive industries should emanate from a forward market; otherwise one would have to assume an expectation that the any new investment would not result in downward pressure on future spot prices. The most effective policy for ensuring adequate and timely new generation investment is to take whatever steps are necessary to establish robust, liquid forward markets.

Precondition 6. Federal-State Regulatory Partnership

The United States is hobbled by split jurisdiction among state and federal authorities in the regulation of the wholesale electricity markets. The fact that consensus does not exist among state regulators with respect to necessary steps for restructuring the electric industry (including whether or not any form of market competition might be a valuable adjunct to jurisdictional oversight) has prevented a rational market structure from evolving even in regions that have attempted to reform retail markets. Even assuming the economic pressures of the global economy are removed from this debate, the insoluble policy differences between federal and state regulators seem insensitive to the continuing need to keep electricity prices or rates at competitively neutral levels across the US.

We cannot continue to advocate a more efficient, lower-cost electric industry without a sense of cooperation between federal and state regulators that any positive objective is worth pursuing. We challenge federal and state officials to resolve this impasse. At risk are American jobs and the continued presence of a competitive American-based manufacturing sector.

A Lesson From the UK

England and Wales restructured their electricity industry several years before the US began to seriously contemplate change. In 1990, the Electricity Pool of England and Wales (“Pool”) was established for the trading of electricity between “generators and suppliers.” As in the Organized Markets, the Pool market design also gave all generators the same market-clearing price. The market design of the Pool was partially

copied by California in 1996 and greatly contributed to interest in the more complex LMP market design adopted by the Organized Markets.

Dissatisfaction with the market outcomes eventually emerged and in 1998 the UK regulator decided to abandon the market design and impose a structure that made forward contracting the main mechanism for energy transactions. An intentionally small balancing mechanism was added. Less than two percent of all energy is now exposed to the balancing mechanism.

Criticisms of The Pool in England & Wales

- Generators have market power
- Capacity payments are unnatural
- Restricted liquidity in forward markets
- Constraint payments unsatisfactory
- No demand side participation
- Unsatisfactory governance structure
- Technical rather than market focus

Source: David Newbery, Electricity Liberalisation in Britain: The Quest for a Satisfactory Market Design, 14 July 2004; Richard Stark, Overview of the NETA Markets, ILEX, 2001.

The table above summarizes criticisms of the English and Welsh Pool. The fact that these problems have been replicated almost one-for-one in the Organized Markets should surprise no one given that the electric industry's technical structure is common to all countries, as is the vulnerability of auctions to generator market power. Ironically, in the UK, coal-fired units were on the margin and other generators (including new gas-fired units) were the beneficiaries of the higher prices. While the roles of natural gas prices in the US and coal prices in UK were reversed, the underlying dynamic was the same, namely that, under a single price auction for an all-encompassing spot market with no Demand Response, the benefits of competition are not shared with end users. The UK regulator's actions were deliberately intended to create generation-on-generation competition and a market structure in which end-use customers would benefit.

FERC is urged to take the same bold action as UK's Regulator in 1998 to reconsider the basic paradigm for a competitive wholesale market. ELCON is not recommending that the UK's New Electricity Trading Arrangements (NETA) be copied in the United States—although a self-scheduled market is certainly worth looking at. However the fact that constructive change was initiated needs urgent replication in this country. US industry and consumers deserve nothing less.

Recommendations

ELCON reaffirms its commitment to implementing a truly competitive wholesale market in the US. Given the assessment of the Organized Markets above, ELCON recommends that following actions:

1. **Forward Market Development.** FERC should immediately commence an inquiry into the causes of the failure of liquid forward markets to form within the Organized Markets. This inquiry should look at, but not be limited to, the following potential impediments to forward contracting:
 - a. Short-term nature of FTRs.
 - b. Guaranteed out-of-market capacity payments.
 - c. Procurement policies of LSEs.
 - d. Generator market power.
 - e. Infra-marginal revenues.
 - f. The practice of allowing the bids of generators with local market power to set the LMPs.
 - g. Existence of duplicative revenue streams for fixed cost recovery and the lack of true “freedom of exit” for generators.
 - h. Credit ratings of generators.
2. **Upgrading the Transmission Infrastructure.** FERC should initiate an inquiry to thoroughly investigate the economic impediments to new transmission investments. This inquiry should investigate why its current incentives for new transmission investments are not effective. FERC should consider conditioning future merger approvals on new transmission construction or as a precondition to market-based rate authority.
3. **Cost of Organized Markets.** FERC should use its ongoing inquiry in Docket No. RM04-12-000 (“Financial Reporting and Cost Accounting, Oversight and Recovery

Practices for Regional Transmission Organizations and Independent System Operators”) to evaluate the costs and consumer benefits of implementing both “Day 1” and “Day 2” of an Organized Market.

4. **Non-Discriminatory ISO/RTO Stakeholder Process.** FERC should require all ISO and RTO boards to propose a stakeholder procedure for weighted voting that is applied on an issue specific basis. The outcome of this procedure should be that no class of market participants or side of the market should be able to unduly influence stakeholder decision making on any matter with which they have a vested interest.
5. **Energy-Only Market.** Assuming liquid forward markets can be established, FERC should commence an inquiry on the benefits of raising the price (“offer”) caps in the spot markets.
6. **Transmission Congestion.** FERC should reconsider its policy to allocate congestion costs to end-use consumers on a nodal or zonal basis because (a) locational pricing and FTRs do not encourage new transmission investments, and (b) the planning and construction of the underlying infrastructure presumed that the costs associated with tradeoffs between the siting of generation in load pockets in lieu of incremental transmission investment would be socialized in average rates.
7. **Long-term Transmission Rights.** FERC should require transmission providers to offer long-term transmission rights to loads.
8. **Demand Response.** FERC should solicit the cooperation of one or more regional state committees for the purpose of testing the viability of Demand Response. This effort should include an assessment of the adequacy of price-responsive load in the marketplace necessary to sustain a competitive wholesale market given the existence of generators with local market power. FERC should also initiate an inquiry to remove entry barriers in the *pro forma* open-access transmission tariff (OATT) to price-responsive load (consistent with state regulations).
9. **Market-Based Rates (MBR).** FERC should use its ongoing rulemaking in Docket No. RM04-7-000 to significantly tighten the requirements for market-based rate (MBR) authority for generators that are affiliates of vertically integrated utilities. This should include conditioning the MBR authority of holding companies that own generation and transmission on the construction of new transmission facilities that mitigate local market power.

10. **MBR in Non-Competitive Markets.** FERC should also pursue in Docket No. RM04-7-000 a market mitigation policy that acknowledges that “prices” derived in any non-competitive markets are not just and reasonable and that this outcome should automatically trigger the suspension of MBR for any suppliers that create or contribute to this situation.

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