

**BEFORE THE
ELECTRIC ENERGY MARKET COMPETITION TASK FORCE**

**Comments on Wholesale)
and Retail Electricity) Docket No. AD05-17
Competition Draft Report)**

**COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION,
INDEPENDENT POWER PRODUCERS OF NEW YORK and INDEPENDENT
ENERGY PRODUCERS OF MAINE**

The Electric Power Supply Association (EPSA), the Independent Power Producers of New York (IPPNY) and the Independent Energy Producers of Maine (IEPM)¹ appreciate the opportunity to comment on the thoughtful Draft Report issued by the Electric Energy Market Competition Task Force (Docket AD05-17). EPSA, IPPNY and IEPM commend the Task Force on a well-written and balanced report that provides the necessary historical perspective on the beginnings of competitive electric markets and the valuable lessons that drove their creation. Those lessons remain valid and relevant today. The Draft Report is timely given the pressing need for a “next wave” of generation and transmission infrastructure to meet the nation’s power needs. As noted in the report (Page 29), competitive suppliers have been the largest contributor to recent generation additions and stand ready, willing and able to continue the legacy of ensuring that costly investment decisions do not put the electricity consumer at risk, as happened prior to competitive electric markets.

The Federal Energy Regulatory Commission (FERC) press release on the Draft Report correctly pointed out that, “The Energy Policy Act of 2005 represents the third major federal law enacted in the past 30 years to promote wholesale competition, following PURPA and the Energy Policy Act of 1992. These laws promoted competition by lowering barriers to entry and increasing transmission

¹ EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers.

IPPNY is a trade association representing companies involved in the development of electric generating facilities; the generation, sale, and marketing of electric power; and the development of natural gas facilities in the state of New York. IPPNY represents over 75 percent of the electric generating capacity in New York.

IEPM is a not-for-profit association of renewable power producers, suppliers of goods and services to those producers, and other supporters of this industry in Maine and elsewhere in New England. IEPM power producer members generate electricity in a sustainable manner from hydropower, biomass, wind, and waste to energy. Located in Augusta, Maine, IEPM supports renewable power and competitive markets before various state, regional, and federal bodies. The comments contained in this filing represent the position of EPSA, IPPNY and IEPM as organizations, but not necessarily the view of any particular member with respect to any specific issue.

access.” In that same release, FERC Chairman Joseph T. Kelliher said it best, “The interagency report reflects that decision.” To further this goal and ensure that the final report reflects the importance of robust competition to electricity consumers, EPSCA offers the observations listed below for consideration by the Task Force.

HISTORICAL PERSPECTIVE

EPSCA, IPPNY and IEPM agree with the approach in the Draft Report of taking a historical perspective on the introduction of competitive markets. As the Draft Report points out, competition was not chosen by Congress and the states in a vacuum. It was no accident that competitive electricity markets were developed after electricity rates skyrocketed in the 1970s and 1980s (Page 29) due to a number of factors, including large cost over-runs in building traditional utility-owned capital intensive baseload power plants (Page 21). As the nation faces a situation today where the need for new baseload plants is looming on the horizon, it is important to remember the past, for those who fail to learn the lessons of history are doomed to repeat them.

It is also important to note that, as the Draft Report recognizes, the energy markets in different regions of the country have developed under vastly different circumstances. Retail competition was introduced in some states and less so or not at all in others. Likewise, regional energy markets have developed in some regions of the country but not in others. Nonetheless, regardless of market structures, electricity prices today are rising in all regions of the country due to increases in fuel prices and other production costs.

It is overly simplistic to conclude, as critics of competition allege, that lower rates in some non-restructured states show that competition is not working in restructured markets. In many cases states that currently do not have retail competition did not restructure their retail markets precisely because their rates were already relatively low; conversely, states that restructured their retail markets often did so because their retail rates were relatively high. As the Draft Report bears out, it is difficult to draw accurate conclusions about the relative merits between restructured and non-restructured states solely based on prices in those markets due to extreme variations in regulatory environments, market structures and timing of the impact of fuel price increases. Nonetheless, the Draft Report accurately recognizes certain trends. For instance, prices of all fuels, not just natural gas, continue to rise and those increases ultimately will lead to higher power prices for end users in all markets. In addition, generators in all states face increased environmental compliance costs due to various federal and state environmental laws, including the Clean Air Interstate Rule and the Clean Air Mercury Rule. Utilities in non-restructured regions, such as the Southeast, are installing billions of dollars in scrubbers and other emissions control equipment which will be included in rate base and show up as higher rates in coming years.

When a competitive supplier builds a power plant, the shareholders of the generation owner are the ones who largely bear the risk of a poor investment – not the captive ratepayers of a vertically-integrated utility. The Task Force properly identified this distinction in at least four separate places throughout the Draft Report (Pages 4, 37, 62 and 68). In restructured states and in regions that hold independently overseen competitive bidding for generation resources, gone are the days when a rate-based plant was built 200 or 300 percent over the initial cost projections with the excess costs primarily footed by captive ratepayers. There is no reason today to allow a company with little incentive to hold costs down and every incentive to “gold-plate” a project – since the more rate-base utilities spend, the larger return they earn – to make the same imprudent baseload investments that created stranded costs and the need for competitive markets in the first place. Instead, all states have the opportunity, through competitive procurement, to ensure that utility ratepayers will not bear the burden of a poor investment, plant cost overrun or construction delay over the complete life cycle of the project.

A particular model of regulation in which a vertically-integrated utility passes along all of its accrued costs to captive ratepayers is sometimes called “cost-based” regulation. However, as noted in the Draft Report (Page 35), the more appropriate term for such a model is “cost-plus,” or, as we would argue, “cost-plus-plus-plus.” It is important to note the distinction in semantics between “cost-based” and “cost-plus.” Under such regulation, a vertically-integrated utility has every incentive to spend as much money as possible to increase their return – such spending is of course passed along to the ratepayer. “Cost-based” infers that vertically-integrated utilities make every effort to ensure that their spending is efficient and limited for the overall benefit of the ratepayer. But why would a vertically-integrated monopoly utility whose profit is a percentage of passed-through costs perform in such a manner? We cannot think of a reason and, as has been demonstrated in past utility spending excesses, the term “cost-plus” is more fitting.

POWER SUPPLY

a) Next Wave of Generation

One of the criticisms most often leveled against competitive generation is that it is all natural gas fueled. While it is true that during the 1990s, with natural gas prices at an all time low and expedited power plant siting processes available, many natural gas fired competitive generation facilities were built to meet the market demand for such plants, today competitive suppliers own and operate a broad mix of nuclear, coal, natural gas and renewable generation facilities.² Competition among generators in North America – even across neighboring

² 36 percent of competitive generation is coal-fired, 30 percent natural gas, 24 percent nuclear, 6 percent hydroelectric and other renewables, and four percent oil-fired, according to EIA data.

markets that offer less of a competitive environment – has resulted in improved operation of plants originally constructed under the traditional rate regulation model as measured by higher capacity factors and lower heat rates.

As the country moves to ensure its energy security through greater fuel diversity, just as competitive suppliers brought natural gas-fired generation online when natural gas prices were low, they will also bring generation online from other fuel sources now that natural gas prices are higher. Based on discussions with member competitive suppliers, EPSA, IPPNY and IEPM are focusing their advocacy efforts on issues surrounding the next wave of generation because their members have plans, some announced and others not, to build new generation. A number of examples of just these types of announced investments by competitive suppliers include:

- NRG Energy, Inc. said that it plans to spend \$16 billion over the next ten years to develop 10,500 megawatts of new nuclear, wind, coal and integrated gasification combined cycle capacity across the country;
- TXU has announced plans to build 11 coal-fired power plants in Texas and up to 8,000 megawatts of coal-fired plants in the rest of the country;
- Constellation Energy and Exelon Corp. have both been active members of separate consortia to develop the next nuclear power plant in the United States;
- BP and Edison Mission Group announced that they are planning a new \$1 billion hydrogen-fueled power plant in California that would generate clean electricity with minimal emissions; and
- AES announced plans to invest \$1 billion over the next three years in renewable energy and greenhouse gas reduction technologies.

When allowed to work, competition provides new, innovative and capital intensive projects built at the lowest cost, greatest efficiency and least risk for ratepayers. Competitive suppliers stand ready to construct and help finance these needed generation projects with the help of regulators at all levels to facilitate the necessary investment climate.

While the Draft Report makes mention of a handful of companies that reorganized under the bankruptcy code (Page 61), it should be noted that, for the most part, the plants continued to be available to sell into the wholesale market. Further, several of these companies have emerged from bankruptcy as successful competitors and developers of new generation whose stock is more attractive than ever to investors. Competitive suppliers are actively pursuing new

generation projects and will continue to do so as market conditions warrant. The key is for policymakers to create a reasonable level of regulatory certainty by, in part, resolving market design, transmission and power procurement rules in a manner conducive to investment. Competitive suppliers are willing and able to actively engage in every region if they know that they will be participating in a fair and open transmission system run by an independent third-party and that transmission owning utilities will not unduly discriminate between affiliate and non-affiliate suppliers in providing transmission service.

Unfortunately, discrimination in providing transmission service does occur to the detriment of not only market participants, but consumers who are prevented from seeing the benefits of a fully robust market in which multiple suppliers would compete to serve them. An arcane accounting issue that has come to the forefront recently is the treatment of purchased power contracts as imputed debt – or debt equivalency (Page 61, Footnote 160). This issue should be addressed in the final report as more than a footnote if the report is to help improve competition going forward. Debt equivalency first emerged in 1990, when the credit rating firm Standard & Poor's (S&P) proposed to apply a “debt-equivalence” risk factor to utility balance sheets for power contracts from third-parties, such as competitive suppliers. Some form of debt equivalency is used today by the three major credit rating agencies (S&P, Moody's and Fitch Ratings), although their specific approaches differ.

Debt equivalency is misused by some utilities to artificially raise the price of a competitor's bid to the detriment and expense of its captive ratepayers – typically when a utility favors constructing and owning its own power plant rather than purchasing less expensive power from the market. These utilities have sought to use this discriminating tactic as a factor in evaluating resource options. If competition is to succeed in the future, state regulators should reject such attempts to tilt the scales on competitive procurement and instead recognize that competitively-procured contracts for power can actually reduce utilities' financial risk compared to self-build options.

b) Organized Markets

As FERC has pointed out elsewhere, two-thirds of the United States economic activity occurs in “organized markets” (areas served through RTOs and ISOs). In an ideal energy market, the full value of a capacity resource would be reflected in the energy price. As supplies become tight, energy prices would rise appropriately and signal to investors that new generation is required, as occurs in other commodity markets. However, this has not been allowed to occur (Page 64). Instead, every organized market has some form of price mitigation that administratively limits the amount that can be paid for power despite underlying supply and demand fundamentals. Nonetheless, power plant operators must still have the opportunity to recover investment and operating costs, and, where

capped prices prevent full recovery in the energy markets, capacity markets are one mechanism that can accomplish this goal.

In other words, capacity markets exist because mitigation measures and other limits on prices in the energy markets have distorted the price signals that would otherwise incent both the demand response and generation investment necessary to maintain a sufficient level of reliability. RTOs and ISOs are currently working with state and federal regulators, consumers, and industry stakeholders to devise mechanisms such as capacity markets to promote needed new investment and to keep existing plants economically viable.

The Draft Report also identifies the recently debated issue between the merits of a uniform clearing price auction or a pay-as-bid auction as the best mechanism in organized markets. As the Task Force pointed out, the uniform clearing price construct used in all organized markets provides generators “an incentive to bid their marginal costs, to maximize their chance of getting dispatched” (Page 67). A uniform price auction also provides incentives for generators to provide as low a bid as possible since “a unit’s profitability in a uniform price auction will depend on whether, and by how much, its production costs are below the market clearing price” (Page 67); many times the generators that set the clearing price, and therefore meet the last increment of demand, earn little or no contribution to their fixed costs. Further, the contributions to fixed cost received by generators with variable costs below the clearing price are an important part of the efficient market signal needed to justify additional investment and recovery of fixed costs in the market.

Because under a uniform clearing price customers are able to see what the cost of the last increment of demand was (since it set the clearing price), the market sends an explicit price signal to conserve electricity. On the other hand, in a pay-as-bid auction, generators will roll all their costs into a single bid and attempt to guess what the highest price selected will be, and then bid to match it. Inevitably, some lower cost generators will bid too high; because all generators will be bidding above their operating costs, market transparency is lost and the risk of manipulation is raised. Economists generally agree that uniform clearing price auctions result in lower prices for consumers than pay-as-bid auctions. In fact, even some critics of competition have acknowledged this fact.

In regard to the length of contracts in the current wholesale marketplace (Page 58), EPSA, IPPNY and IEPM are supportive of any market design that provides the long-term cost and regulatory certainty conducive to bilateral contracts for electric supply. Such a market would provide both buyer and seller with contract options and would send clear price signals for any needed investments.

Similarly, EPSA, IPPNY and IEPM are supportive of a long-term transmission rights product developed in restructured markets that adheres to the system

operator's FERC-approved tariff. Such a product should be the result of a broad stakeholder effort and study by the region's system operator.

TRANSMISSION

EPSA, IPPNY and IEPM agree with the Draft Report that a utility that owns both transmission and generation assets in a given region has little to no incentive to then build more transmission for the sake of lowering costs to its customers through access to suppliers other than the utility (Pages 4 and 28). Because of this inherent disincentive, as well as the integrated nature of our nation's electric system, all transmission planning should be independently conducted on a regional basis with participation from state and federal agencies, vertically-integrated and transmission dependent utilities, and competitive suppliers. The regional plan should facilitate the needs of all transmission users and actually be implemented following its preparation. EPSA, IPPNY and IEPM applaud the initial steps taken in the Energy Policy Act of 2005 and FERC's recently proposed revision of Order No. 888. EPSA, IPPNY and IEPM urge state and federal regulators and legislators to take further initiative and require that all planning be independently administered with input from all stakeholders and completed within a mandatory timeframe.

As noted by the Task Force – and three times formally by FERC since its issuance – while Order No. 888 was a monumental step toward the creation of robust and fair competitive markets, it has not stopped transmission owners from discriminating against non-affiliated generators (Page 23). Such discrimination has proven harmful to not only sellers in power markets, but also to buyers. The Draft Report correctly observes that “Transmission discrimination can increase delivery risk because purchasers feared that their transmission transactions might be terminated for anticompetitive reasons by their vertically integrated rival, were they to purchase generation from a generator who is not affiliated with the transmission provider” (Page 48).

The surest way to alleviate the risk of transmission discrimination inherent in the territory of a vertically-integrated utility – “these utilities have an incentive to limit the use by others of the grid” (Page 65) – would be to, “turn over operation of the transmission grid in a region to an independent operator, like the ones that now operate in New England, New York, the Mid-Atlantic, Texas, and California (“organized markets”). With the market design in these regions, there is no risk that a wholesale customer will not be able to deliver power to its retail customers...” (Page 48). It is for these reasons and more that EPSA, IPPNY and IEPM concur with the Task Force in applauding FERC for revisiting and reforming the landmark Order 888 rulemaking, to ensure fairness outside of the organized markets, and we look forward to continuing to work with FERC on ensuring that non-discriminatory access to the grid is ensured for all.

IS WHOLESALE COMPETITION WORKING?

In the Draft Report, the Task Force asks whether wholesale competition is working (Page 2). The short answer is that wholesale competition is indeed working, but improvements can and should be made to make it work even better. Specific problems with particular market challenges should be fixed, not used as a reason to “put the genie back in the bottle” and roll-back competition to advantage those who benefit from a lack of competition. Doing so is the surest path to harming consumers.

As noted in our initial comments to the Task Force on Nov.18, 2005, a study by Global Energy Decisions, Inc., “Putting Competitive Power Markets to the Test,” concluded that competitive wholesale power markets in the eastern United States and Canada produced at least \$15.1 billion in customer savings during 1999-2003 in the Eastern Interconnection alone. In addition, an October 2005 study on industry restructuring by the Cambridge Energy Research Associates (CERA) found that “U.S. residential electric consumers paid about \$34 billion less for the electricity they consumed over the past seven years than they would have paid if traditional regulation had continued.”³

In 2002, the Department of Energy determined that wholesale electricity markets saved consumers an estimated \$13 billion annually in energy costs. “On average, wholesale power transactions reduced generation costs, in the aggregate, by approximately \$370,000 per hour in the East and by more than \$1,000,000 per hour in the West. These savings translate directly to lower prices for consumers.”⁴ And in New England, competition led to a 5.7 percent decline in prices, after adjustment for fuel prices, since the first full year of operations. “A dramatic price decline of 11 percent was experienced in New England from 2001 to 2004.”⁵

The Draft Report properly states a number of the benefits of competitive markets as opposed to the traditional rate based approach:

- Under cost-based regulation, “it was long term planners and regulators that determined when generation would be built, and it was consumers who bore the cost of investment risks once they had been approved by state regulators.” (Page 37)

³ Cambridge Energy Research Associates (CERA), “Beyond the Crossroads, The Future Direction of Power Industry Restructuring” (CERA Report), at I-1 (October 2005). This cumulative net gain takes account of the losses associated with the electricity crisis in California and the West during the 2000-2001 period. According to CERA, the cumulative estimated savings in non-western regions over the deregulation period in real 1997 dollars was actually \$42 billion. See CERA Report at I-12, I-15.

⁴ Department of Energy National Transmission Grid Study (National Transmission Grid Study) at 19 (May 2002).

⁵ ISO New England, “Progress of New England’s Restructured Electric Industry and Competitive Markets: The Benefits of ISOs and RTOs” (ISO New England Progress), at 2 (April 2005).

- “While the intent of cost-based rate regulation, was not simply to keep price down, the effect was sometimes to dampen investment in new capacity and innovation... Utilities also had little incentive to design new generation plants in a cost-effective manner, to the extent regulators were unlikely to identify and disallow excessive costs to be included in customer rates.” (Page 37)
- “Under traditional cost-base rate regulation, utility investment decisions were based in part on the promise of a regulated revenue stream with little associated risk to the utility. The ratepayers often bore the risk... One significant problem, however, was that regulators had limited ability to ensure that utilities spent their money wisely.” (Page 62)
- “...customers under historical cost-based regulation paid average prices calculated over an extended period of months or years that did not vary with their consumption or with variation in the cost of generating electric power. Thus, wholesale and retail customers did not receive economically accurate price signals to guide their consumption decisions.” (Page 35)

CONCLUSION

EPSA, IPPNY and IEPM, again, strongly applaud the Task Force for developing a thoughtful, comprehensive and timely Draft Report on the state of competitive wholesale markets. Congress has repeatedly shown its intent to support and enhance competitive wholesale markets so that consumers may maximize benefits. Competitive markets have, and will continue, to prove to be the best means to derive the most efficiency and innovation from the electric industry to benefit consumers. Competition provides a transfer of risk for costly and risky investments while also ensuring that the lowest cost resource is being obtained on behalf of consumers. Our society and economic system do not tolerate monopolistic practices in other industries; there is no legitimate reason to treat electricity any differently.

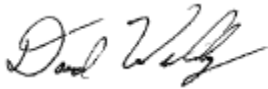
Respectfully submitted June 23, 2006,



John E. Shelk
President & CEO
Electric Power Supply Association



Gavin Donohue
President and CEO
Independent Power Producers of New York, Inc.



David A. Wilby
Executive Director
Independent Energy Producers of Maine