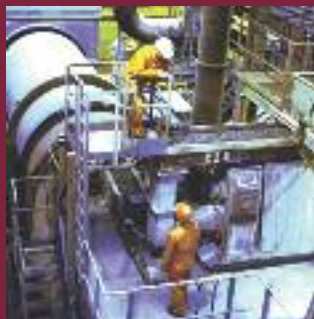
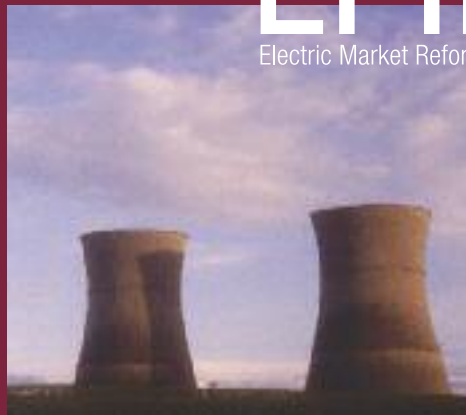


# APPA's Competitive Market Plan

A Roadmap for Reforming Wholesale Electricity Markets



**EMRI**<sup>®</sup>  
Electric Market Reform Initiative

**APPA**<sup>®</sup> American  
Public Power  
Association



# APPA's Competitive Market Plan

A Roadmap for Reforming Wholesale Electricity Markets

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## I. **Executive Summary**



This paper presents the American Public Power Association's (APPA) Competitive Market Plan for reform of wholesale electricity markets administered by regional transmission organizations (RTOs). The plan was developed based upon results of investigative studies carried out under APPA's Electric Market Reform Initiative (EMRI) and consultation with APPA members, other market participants and electricity industry experts.

APPA has developed the Competitive Market Plan to attempt to remedy the absence of meaningful competition and consumer protections under the current RTO market model, while still assuring resource adequacy. The changes proposed in this paper are only for regions with RTO-run centralized wholesale power supply markets under federal jurisdiction. APPA is not suggesting that geographic regions without RTOs adopt these proposals. Along with the proposed reforms, APPA is also recommending a moratorium on the development of new RTO markets, at least in the absence of strong, widespread RTO member support for them.

APPA is recommending the following primary changes to the Day 2 RTO markets. These changes are intended to move these markets from de facto oligopolies to more competitive markets, while ensuring reliable electric service at just and reasonable rates.



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## **Power Supply Markets**

- Current RTO-run energy and ancillary services real-time and day-ahead markets would be replaced by an RTO-run “optimization” market, in which customers can balance supply deficiencies or excess purchases, and generators can sell excess generation.
- Offers to sell into the optimization market for both energy and ancillary services would be limited to generators’ marginal costs of generation. Generators would be required to submit their unit-specific operating costs to the RTO market monitor in advance to provide cost support for their offers. Prices would be set initially using a cost-based single-clearing price mechanism, with evaluation of the results of that mechanism after three years of operation.
- The optimization market would contain a cost-based day-ahead component for the purpose of generation resource commitment.
- Generator offers into the optimization market would be made public on the next operating day, including the identity of bidders.
- FERC-jurisdictional generators entering into bilateral contracts with load-serving entities (LSEs) in an RTO region would not be subject to cost-based restrictions, i.e., they could use market-based rates if they have obtained such authority from FERC. APPA recommends, however, that FERC separately evaluate generation market power for long-term power supply products in determining seller eligibility for market-based rate authority.
- Generators would be subject to a must-offer requirement into the optimization market for energy not already committed under bilateral contracts or owned generation arrangements (subject to forced outages, scheduled maintenance, and special rules for limited-run units).
- Demand-side resources could sell into the optimization market, but would not be subject to a cost-based offer restriction; rather, they would take the single-clearing price that clears the market, assuming they have previously offered to reduce demand at that price level.

## **Resource Adequacy**

- Existing RTO-administered locational capacity markets would be phased out and capacity would be supplied through bilateral contracts entered into by LSEs with resource suppliers (both generation and demand response), LSE-owned generation arrangements and LSE-managed demand response.
- The RTOs would determine and implement overall resource adequacy standards applicable to LSEs within the RTO footprint. States would have substantial input into RTO development of regional transmission plans and regional resource adequacy requirements.
- States would establish resource acquisition processes to secure a diversified portfolio of generation and demand-side resources for state-regulated investor-owned utility (IOU) LSEs. Competitive procurements,

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including consideration of both LSE self-build/self-supply and third-party supplier options, would be conducted for state-regulated IOU LSEs, with an option for self-regulated LSEs to participate.

- States and LSEs would be free to explore broader LSE resource procurement initiatives, such as regional procurements or LSE resource pooling.

### **RTO Dispatch and Transmission Operation**

- RTOs would conduct centralized least-cost dispatch of generators based on actual operating costs. Generators and demand response providers would be paid based upon contracted prices for quantities sold through the bilateral market. For quantities sold through the optimization market, generators and demand responders would receive the cost-based market-clearing price.
- Data on bilateral contracts would be submitted to the RTO for the purposes of market monitoring, running feasibility tests to assess transmission adequacy, and developing regional transmission plans.
- Financial transmission rights (FTRs) would be allocated to LSEs. Long-term FTRs would also be granted to support longer-term (e.g., 10-year) bilateral power supply arrangements and LSE-owned resources.
- Existing transmission rights would be maintained to the maximum extent feasible.
- RTOs would continue to ensure non-discriminatory open access to the transmission system.

APPA recommends as part of its Plan that FERC conduct periodic reviews of wholesale power supply markets in RTO regions, to assess long-term price stability, possible exercises of market power, justness and reasonableness of rates, and reliability. To the extent that reformed RTO markets are not making adequate progress in providing balanced incentives and benefits to both generator and load interests, further reforms would need to be considered.

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## II. Introduction



This paper presents the American Public Power Association's (APPA) plan for reform of wholesale electricity markets administered by regional transmission organizations (RTOs). The plan was developed based upon results of investigative studies carried out under APPA's Electric Market Reform Initiative (EMRI) and consultation with APPA members, other market participants, and electricity industry experts.

APPA initiated EMRI in response to fundamental changes in the wholesale electricity markets over the past 15 years. The Federal Energy Regulatory Commission (FERC) shifted its policy emphasis from ensuring non-discriminatory open access transmission service to implementing centralized RTO-run wholesale electric markets, with only limited wholesale price regulation. Meanwhile, many states implemented retail access programs to provide retail consumers with a choice of electricity providers. In many of these states, investor-owned utilities (IOUs) sold off their generating plants to third parties (in many cases, their unregulated affiliates), which can sell their power at prices that are no longer tied to the costs of production, and are subject only to limited RTO "market mitigation" rules.

In response to growing problems public power utilities were experiencing obtaining power supplies in RTO regions with centralized power supply markets, APPA launched EMRI in March 2006 to investigate restructured wholesale electricity markets and develop needed reforms to those markets.

Under this initiative, APPA commissioned a series of studies investigating the restructured RTO-run wholesale markets under federal jurisdiction.<sup>1</sup> Based on the results of these studies, APPA concluded that RTO-run centralized wholesale markets had substantial problems, and were not yielding "just and reasonable rates," as the Federal Power Act (FPA)<sup>2</sup> requires. APPA therefore embarked on the development of potential reforms to these markets.

A fundamental reason for restructuring of electricity markets was the expectation that the combination of open access transmission service and RTO-operated centralized wholesale markets would promote "competition." This increased competition in turn would spur efficiencies and innovation, ensure adequate supplies and, most importantly, lower rates for consumers. But the EMRI studies and the real-world experience of consumers shows that the opposite has occurred. These deregulated markets produced both higher prices and higher profits than one would expect in a competitive market. Prices exceed those prevailing in the remaining regions that have not

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<sup>1</sup> The results of these studies are available on the EMRI section of APPA's Web site at: [www.APPAnet.org/emri.cfm](http://www.APPAnet.org/emri.cfm)

<sup>2</sup> FPA Sections 205 and 206, 16 U.S.C. §§ 824d, 824e.

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restructured and have retained cost-of-service regulation. The greatest beneficiaries of restructuring are not consumers, or the new, innovative companies that were promised to emerge under competition, but the owners of large fleets of previously regulated, largely depreciated generation units.

APPA has developed this “Competitive Market Plan” to attempt to remedy the absence of meaningful competition and consumer protections under the current RTO market model, while still assuring resource adequacy. The changes proposed in this paper are only for regions with RTO-run centralized wholesale power supply markets under federal jurisdiction. APPA is not suggesting that geographic regions without RTOs adopt these proposals. Along with the proposed reforms, APPA is also recommending a moratorium on the development of new RTO markets, at least in the absence of strong, widespread RTO member support for them.

Although the changes APPA proposes would require a lengthy implementation period, APPA has made substantial efforts to work within the existing RTO structure. Current RTO market structures are extremely complicated and cannot be easily modified. To the extent that current features of RTO markets are maintained, this should not be construed as an APPA endorsement of such features, but rather recognition that a complete overhaul of the existing markets would be very difficult to accomplish. APPA is hopeful that its proposal will spark a dialogue on meaningful reforms to RTO-run markets that will provide substantial benefits to both customers and energy suppliers.

### **Goals of the Competitive Market Plan**

APPA intends that its Plan would produce the following outcomes:

- Increase the availability of long-term bilateral power supply contracts (e.g., a 10-year term) and opportunities for LSE-owned generation, in turn enhancing the viability of financing new generation and renewable energy technologies.
- Reduced opportunities for generators to exercise market power.
- Transmission planning and construction processes that support long-term bilateral contracts/generation ownership and the new generation resources developed with the support of such power supply arrangements.
- Greater opportunities for LSEs to hedge congestion and reduced speculative opportunities for financial-only market participants.
- Reduced power supply price volatility and wholesale electricity rates that comport with the just and reasonable standard of the Federal Power Act.
- Resource adequacy standards, increased bilateral contracting and use of owned generation, and an optimization market that together would improve the reliability of electricity service.



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### III. Background



his plan originated in a proposal, first presented in APPA's February 2008 paper "*Consumers in Peril*,"<sup>3</sup> to restructure current "Day Two" RTOs as "Day One" RTOs.<sup>4</sup> After careful investigation and refinement of this concept, APPA has decided that the best approach would be to develop a hybrid of the best elements of both RTO structures.

Current Day Two RTOs operating in the United States include the PJM Interconnection ("PJM"), the Midwest Independent System Operator ("MISO"), ISO-New England ("ISO-NE") and the New York Independent System Operator ("NYISO"). The Southwest Power Pool ("SPP") is currently the only example of a Federal Energy Regulatory Commission (FERC)-approved Day One RTO.<sup>5</sup> California's current market (run by the California ISO, or CAISO) also has some features of a Day One market model, although it plans to move in the near future to a Day Two model as part of its Market Redesign and Technology Upgrade (MRTU).<sup>6</sup> For the remainder of this paper, the term RTO will be used to refer to a Day Two RTO.

This paper will not delve into all of the problems LSEs have experienced with RTOs. To briefly summarize, APPA's Competitive Market Plan was developed to remedy the most problematic aspects of RTO markets, which are briefly outlined below and discussed in greater detail in *Consumers in Peril*<sup>7</sup>:

- The use of bid-based offers into the day-ahead and real-time markets provides opportunities for potential exercises of market power through the use of strategic bidding strategies, and the absence of any real relationship between prices and marginal costs reduces the price transparency needed for true competition.
- The lucrative nature of the RTO-operated energy and capacity markets has produced supra-competitive profits and has made sellers reluctant to enter into long-term bilateral power supply contracts at prices not directly linked to RTO-run spot market prices (plus substantial premiums in some cases).

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<sup>3</sup> "*Consumers in Peril: Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates*," APPA, February 2008 available at: <http://www.appanet.org/files/PDFs/ConsumersinPeril.pdf>. The policy recommendation to restructure RTO markets appears in Section 5, which is the focus of this document.

<sup>4</sup> A "Day Two" RTO refers to a market structure where the RTO manages the transmission grid within its footprint to ensure non-discriminatory transmission access and reliability, runs centralized markets for energy (day-ahead and real-time) priced using locational marginal pricing concepts, and provides financial transmission rights (FTRs) to hedge the associated transmission congestion costs. Depending on the market design, a Day Two RTO may also run centralized markets for ancillary services and capacity. A Day One RTO does not administer centralized spot markets, except perhaps for a balancing market, but does oversee management of the transmission grid for reliability and open-access purposes.

<sup>5</sup> SPP has announced its intent to implement a Day Two market in 2012. See Future Market Implementation, SPP Market Working Group, timeline on slide 93. <http://www.spp.org/publications/Feb%202nd%20Information%20Session%20v6.0%20-%20With%20supplemental%20material.pdf>. It is not known at this time the degree to which the transition will be completed by the intended date.

<sup>6</sup> California ISO's most recently available expected date for MRTU operation is April 2009. See MRTU Timeline as of 18-Dec-2008 (Revised), <http://www.caiso.com/20a1/20a1c2352bf80.xls>

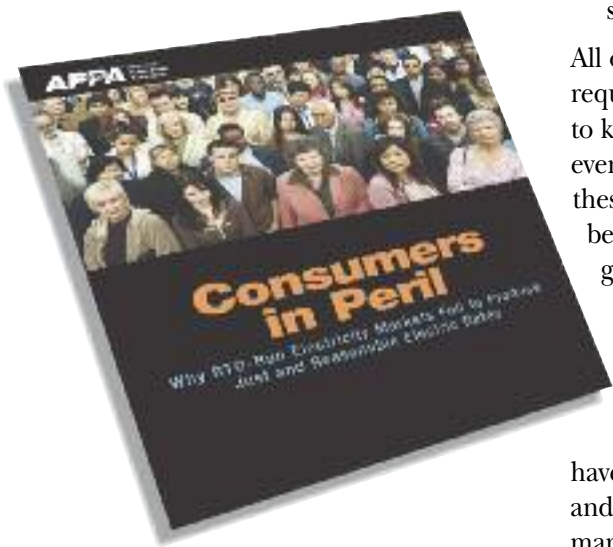
<sup>7</sup> See Ch. 4 of "*Consumers in Peril: Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates*."

- Excessive reliance by RTOs on often ineffective market and pricing incentives to address transmission congestion and anticipated capacity shortfalls has substantially increased costs to electric consumers.
- Locational capacity markets are producing high capacity prices and opportunities for economic withholding, leading to substantial overpayments for capacity additions.
- Hedge funds, investment banks and other financial entities are participating in RTO markets through FTR auctions and virtual bids in spot markets, potentially increasing costs to consumers.

All of these problems point to markets that are inherently uncompetitive, requiring significant interventions from market monitors and other regulators to keep generators from exercising overt market power and raising prices even during non-peak periods. Even with aggressive market monitoring, these RTOs' market rules and institutions have created a system where the benefits of competition flow disproportionately to owners of existing generation.

FERC and the RTOs have been largely unwilling to investigate and acknowledge the problems with these markets.<sup>8</sup> Instead, each difficulty is met with a new, complicated market and/or pricing incentive. For example, in the face of looming shortfalls in generation capacity, RTOs have responded only to complaints of generators that RTO mitigation rules and protocols prevent them from earning sufficient revenues in the energy market to recover the fixed costs or going-forward costs of generating units (the "missing money" problem). In response, the RTOs have created a number of secondary markets, such as those for locational capacity and ancillary services. A number of reports have challenged the validity of the missing money problem and suggested that these secondary markets are even less competitive than RTO-run spot energy markets.<sup>9</sup>

The layering on of new markets has created such a level of complexity that highly sophisticated entities have a built-in advantage in participating in RTO markets. Such complexity also impairs transparency and makes the task of market monitoring more difficult.



<sup>8</sup> For example, a 2008 study by the Government Accountability Office (GAO) found that "FERC has not conducted an empirical analysis to measure whether RTOs have achieved these expected benefits or how RTOs or restructuring efforts more generally have affected consumer electricity prices, costs of production, or infrastructure investment." *Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance*, p.55, GAO-08-987, September 2008, <http://www.gao.gov/new.items/d08987.pdf>.

<sup>9</sup> See, for example, T. Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," report for APPA, September 2007. Available at: <http://www.appanet.org/files/PDFs/StudyMountEMRreportNYISOCapacity09%2D07.pdf>. Also, see James Wilson, Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model, February 2008, available at <http://appanet.org/files/PDFs/RPMreport2008.pdf>. Reports from the PJM market monitor also concluded that the capacity markets are often not competitive. For example, Joseph Bowring, PJM's market monitor, concluded that "the market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership." Analysis of the 2009-2010 RPM Auction, Feb. 11, 2008, <http://www.pjm.com/markets/market-monitor/downloads/mmu-presentations/20092010-rpm-review.pdf>.

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## IV. Overview of Proposed Market Structure



PPA developed its Competitive Market Plan to support the following design goals:

- Reduced opportunities for the exercise of market power, and sufficient data transparency to identify market power abuses;
- For load not served by owned resources, an increased emphasis on long-term bilateral contracts (e.g., 10 years or longer) to support reliable service to customers at reasonable rates and to finance needed new generation and demand response resources, with minimal dependence on short-term energy markets to obtain power supplies;
- Provision of open-access non-discriminatory transmission service;
- Transmission and resource planning to meet reliability and environmental-stewardship goals over time at the lowest cost, rather than merely to support long-distance, short-term transactions;
- Minimization of market and operations complexity, and maximum procedural and data transparency for market participants, regulators and the general public.

To accomplish these goals, APPA recommends that current RTO Day Two markets be reformed to retain the beneficial functions of RTOs, while modifying or phasing out problematic market design features. Under this plan, an RTO would offer transmission service to support open access to the transmission system, operate a marginal cost-limited single-clearing price “optimization market” for short-term procurement of energy and ancillary services, implement RTO-determined region-wide resource adequacy requirements, and plan for transmission facilities and service needed to support LSE-owned and contracted-for resources. Long-term bilateral power supply agreements between LSEs and generators/demand-side providers and LSE-owned resource arrangements would be the primary methods of procuring resources.

To arrive at its proposed model, APPA reviewed other wholesale market models in existence. The bilateral-based trading regime of the Western Systems Power Pool (“WSPP”) was one model that APPA examined. There are, however, both operational and transition problems in replicating the WSPP model in the Eastern RTO footprints. The bilateral trading model of the WSPP has worked well in the portion of the Western Electricity Coordinating Council (“WECC”) not served by the California Independent System Operator (“CAISO”) for many years, but the Western Interconnect is fundamentally different from the Eastern Interconnect. The West has traditionally been dominated by large federally funded hydroelectric projects, whereas hydro power is a small percentage of energy supply in many parts of the East. Load centers in the West are separated by large geographic distances, so the primary transmission grid in the West is much less meshed than the grid in the East. The WSPP has developed a large number of liquid pricing points



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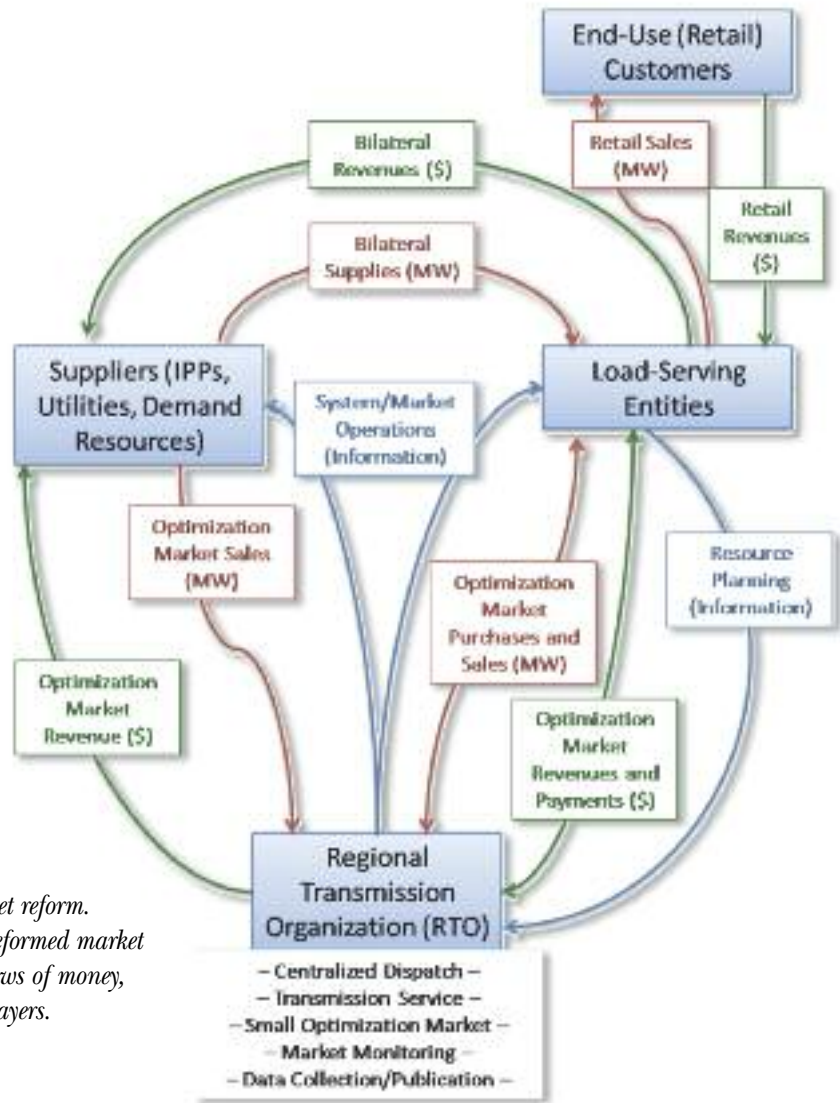
for bilateral energy that correspond to load centers or transmission interconnections, while the East has a smaller number of bilateral pricing points, relative to the size of the system, and has historically required more direct intervention by transmission operators to manage congestion. But most important, market participants in Eastern RTO regions (including many APPA members) have invested very substantial sums of money in assets and contracts based on an RTO-market paradigm. The possible “stranding” of investments and contractual arrangements inherent in implementing a non-RTO based, WSPP bilateral contract model in the Eastern RTO regions is simply too great to make this a viable policy option. APPA is accordingly proposing a hybrid approach that would borrow some elements from the WSPP model.

APPA has concluded, based on communications with APPA’s members and observations of the current markets, that it would be very difficult to radically overhaul the current RTO-operated markets. In particular, it would be difficult to revert to the use of physical transmission rights rather than financial rights. To do so would upend numerous contracts and arrangements to serve load, as well as planned construction of power plants.

APPA’s Competitive Market Plan therefore would include the following features, which are described in greater detail in this paper:

- RTO operation of a residual, marginal cost-limited single-clearing price “optimization market” for balancing and short-term procurement of energy and ancillary services.
- Use of long-term bilateral power supply agreements and resource ownership as the primary methods of obtaining generation and demand-side resources.
- Non-discriminatory open access to the transmission system and provision of long-term transmission rights to support LSE resource arrangements.
- Provision of data on generator costs and optimization market offers to the public on a timely basis.
- Centralized RTO dispatch of generation, using actual cost data as the basis of dispatch, rather than bid-based offers.
- Phase-out of existing locational capacity markets.
- RTO-set resource adequacy requirements for all LSEs to be met through portfolios of generation, demand response and energy efficiency resources.
- State supervision of resource procurement for state-regulated IOU LSEs, with emphasis on developing a diverse portfolio of resources of varying fuel types and terms.

The structure of APPA’s new market design is shown on page 13. The diagram flows of money (green arrows), energy (red arrows) and information/data (blue arrows) among independent generation supply companies, LSEs, the RTO and



*Schematic chart of APPA's proposed RTO market reform. Blue boxes indicate the primary players in the reformed market design. Green, red and blue arrows indicate flows of money, energy and information (or data) among the players.*

end-use customers. Bilateral contracts, self-supply through resource ownership, and demand response form the foundation of the new market design.<sup>10</sup>

The purpose of emphasizing long-term bilateral contracts and generation ownership arrangements is to make the market structure more compatible with current financial realities and longer-range system planning for generation, transmission and demand response. Under the current market structure, investment decisions must be based on far-forward expectations of hourly market prices, the volatility of which may discourage the development of appropriate risk-management products and practices.<sup>11</sup> The RTO would continue to act as a regional transmission-management entity, but its

<sup>10</sup> Not shown in the illustration, but likely relevant to the new market design are brokers – players who match buy and sell offers in bilateral markets but do not themselves take any physical position in the market.

<sup>11</sup> L.B. Lave, J. Apt and S. Blumsack, 2007. “Deregulation/Restructuring Part I: Re-Regulation will not Fix the Problems,” *Electricity Journal* 20:8, pp. 9 – 22.



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operations would shift in focus to supporting bilateral contracts and owned generation arrangements, rather than operating expansive centralized spot markets. The RTO would continue to dispatch generation centrally to ensure open-access and reliability, but would provide long-term transmission rights (LTTRs) more compatible with the use of bilateral and resource ownership arrangements for long-term power supply. The RTO would perform residual centralized real-time optimization market functions. APPA expects, however, that under its proposal, sales in the optimization market would constitute a much smaller portion of total energy sales. Finally, the distribution side of the market would not change substantially, with regulated distribution utilities still responsible for physical delivery of power supplies to end-use customers.<sup>12</sup>

The reforms laid out in this paper could not be implemented within a short time frame. It has been close to 10 years since Order No. 2000 was issued, encouraging the formation of RTOs. The problems with RTO markets have been building ever since, and would take a number of years to address. A number of complex FERC proceedings would be required to develop and approve tariff changes for each RTO, many of which are likely to be contentious. Moreover, there are differences among the RTOs themselves. Implementation of the APPA Plan would therefore need to be tailored on an individual RTO basis. But the longer the industry and FERC wait to begin this important task, the longer it will be before consumers begin to see the benefits of the market reforms.

APPA recommends as part of its Plan that FERC conduct periodic reviews of wholesale power supply markets in RTO regions, to assess long-term price stability, possible exercises of market power, justness and reasonableness of rates, and reliability. To the extent that reformed RTO markets are not making adequate progress in providing balanced incentives and benefits to both generator and load interests, further reforms would need to be considered.

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<sup>12</sup> Third-party retail suppliers may have a diminished role in the new market regime. Retail access policy decisions should still be up to individual states, but competitive retail suppliers would need to be willing and able to meet longer-term resource adequacy requirements applicable to LSEs, either directly or through arrangements with third parties.

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## V. Role of State Regulatory Agencies



While much of this paper is focused on the policy decisions FERC and the RTOs must make regarding wholesale market design and regulation, needed reforms to the wholesale markets cannot be accomplished without parallel changes to state policies. Retail access policies would still be left up to individual states, but, under the APPA Plan, competitive LSEs providing service in retail access states would have to meet the rigorous resource adequacy requirements applicable to LSEs, either directly or through arrangements with third parties.

The power purchases that incumbent IOU LSEs in retail access states make to support default supply service to retail customers that have not chosen a third-party supplier (often called “standard offer service” or SOS) have a substantial impact on wholesale market prices. In such states, the power supplies that incumbent LSEs use to provide SOS are typically purchased through state-run auctions for relatively short-term (usually two- to four-year) contracts.<sup>13</sup> As discussed later in this paper, the prices offered under these contracts are frequently based on forward projections of the prices likely to be set in RTO-run centralized spot markets. The relatively short-term nature of the SOS procurement auctions have therefore reinforced the connection between RTO-run spot market prices and bilateral contract prices, rather than allowing bilateral contract prices to act as a check on spot market prices. Generators selling under SOS auction contracts effectively obtain the benefits of RTO spot market pricing, as well as additional risk premiums included in the auction prices. Given such profit opportunities, it is not surprising that other LSEs and large end users attempting to procure wholesale power supplies through bilateral contracts, such as public power and large industrials, would find it difficult to obtain reasonably priced contracts. Changes in state



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policies that allow their incumbent LSEs to purchase or build generation facilities or enter into long-term (e.g., 10-15 year) power supply arrangements to provide SOS to their retail customers would impose needed discipline on the wholesale market.

An essential component of APPA's Competitive Market Plan is a strong recommendation that state public service commissions establish competitive power supply procurement processes to develop diversified resource portfolios for incumbent IOU LSEs, with a significant portion of their power supplies being obtained under longer-term contracts or owned-generation arrangements. These measures could provide much needed price discipline in RTO-run centralized markets, as well as a steady revenue stream to support construction of new generation resources and investment in demand response technologies.<sup>14</sup> Such a state-level procurement process is described in greater detail in Section X (Resource Adequacy).

As part of such an improved SOS power supply procurement process, retail access states should allow their incumbent IOU LSEs to consider "self-builds" as generation resource options. In many retail choice states, incumbent LSEs are currently prohibited from building new generation (except through an unregulated affiliate), even though they still bear responsibility for providing SOS service. The availability of self-build options brings additional competitive discipline to bear on third-party suppliers submitting generation supply offers in power supply procurements. Such state-implemented measures to provide additional sources of supply would also reduce the impact of tight supply conditions that can drive up prices.<sup>15</sup>

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<sup>13</sup> One such auction is the New Jersey Basic Generation Service or BGS auction. A full description of the BGS auction regime can be found at: State of New Jersey, Board of Public Utilities, BGS Auction, <http://www.state.nj.us/bpu/divisions/energy/bgs.html>

<sup>14</sup> A recent report by the Maryland Public Service Commission finds that long-term power purchase agreements (PPAs) would encourage needed generation and lower wholesale market costs. See p. 28, Final Report of the Public Service Commission of Maryland to the Maryland General Assembly Options for Re-Regulation and New Generation, [http://webapp.psc.state.md.us/Intranet/sitesearch/whats\\_new/MD%20PSC%20SB400%20Final%20Report%20to%20the%20MD%20General%20Assembly.pdf](http://webapp.psc.state.md.us/Intranet/sitesearch/whats_new/MD%20PSC%20SB400%20Final%20Report%20to%20the%20MD%20General%20Assembly.pdf)

In a Connecticut proceeding, Levitan & Associates found that "[n]ew generation in Connecticut anchored under a long-term contract should thus help put downward pressure on energy prices in Connecticut," and that "[f]uel diversity objectives in New England could be promoted through long term contracts." Comments Of Levitan & Associates, Inc., DPUC Development And Review Of Standard Service And Supplier Of Last Resort Service Docket No. 06-01-08PH01 Jan. 30, 2007, pp. 4 and 11, [http://www.dpuc.state.ct.us/dockhist.nsf/f068a53a31082a558525664e00498f40/3bf2ed4f4da8cfe3852573f000640cf6/\\$FILE/LAI%20Comments%2030Jan07.pdf](http://www.dpuc.state.ct.us/dockhist.nsf/f068a53a31082a558525664e00498f40/3bf2ed4f4da8cfe3852573f000640cf6/$FILE/LAI%20Comments%2030Jan07.pdf).

<sup>15</sup> A study by Fitch Ratings of 2007 financial performance of generation owners found that: "Tightening power supplies and rising market-clearing heat rates in most U.S. regions have more than offset rising fuel and other operating costs in 2007 and favorably affected cash flow." (Emphasis added.) U.S. Electric and Gas Financial Peer Study, May 2008, Fitch Ratings, p. 2, [http://www.fitchratings.com/corporate/reports/report\\_frame.cfm?rpt\\_id=387488](http://www.fitchratings.com/corporate/reports/report_frame.cfm?rpt_id=387488)



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## VI. Bilateral Contracts



One of the core features of APPA's RTO market redesign proposal is that LSEs would serve their loads with a combination of owned generation/demand-side resources and generation/demand-side resources obtained under longer term bilateral contracts. Market participants (wholesale buyers and sellers) could enter into any contractual arrangement acceptable to both parties, subject to state and RTO requirements governing the resource portfolio of each LSE and the eligibility of the seller for market-based rate authority (as discussed below).

To support the financing of power plants, ownership arrangements or bilateral contracts of at least 10 to 15 years in length would be needed. Such arrangements and contracts would also provide needed price stability for LSEs and their retail customers. APPA, however, is not in this proposal specifying minimum or specific contract lengths and terms. This is because each LSE would likely desire to develop a portfolio of diverse resources of varying lengths and terms. Rather, the Competitive Market Plan is intended to improve the overall market environment by making a significant number of long-term power supply arrangements of 10 years or longer readily available to buyers and sellers. The RTO's optimization market would allow for residual optimization of LSE energy supply arrangements and balancing in real-time.

APPA is proposing these market structure improvements in response to reports from APPA members and large end-use customers that in the current RTO markets, long-term, reasonably-priced bilateral contracts are difficult to arrange (especially full-requirements contracts).<sup>16</sup> Many buyers report that the high prices sellers can obtain in the bid-based RTO-run spot markets discourage the signing of long-term contracts, or result in contract offers directly linked to spot market prices.<sup>17</sup> Studies of bilateral markets in RTO regions have shown that such RTO markets pose impediments to reasonably priced long-term bilateral contracting.<sup>18</sup>

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<sup>16</sup> Communications with APPA members, and testimony summarized in "Executives describe real-world problems with RTOs," *Public Power Daily*, Feb. 29, 2008, <http://appanet.org/newsletters/ppdailydetail.cfm?ItemNumber=21269&sn.ItemNumber=0> (Login required);

<sup>17</sup> For example, Walter Brockway of Alcoa testified before FERC in its Technical Conference on May 8, 2007: "We found no supplier willing to discuss supplying us with anything other than electricity priced to reflect peak load generation, as well as placing on us all the risk of transmission congestion." <http://www.ferc.gov/EventCalendar/Files/20070508083948-Brockway,%20Alcoa.pdf>.

<sup>18</sup> E. Hausman, R. Hornby and A. Smith, Synapse Energy Economics, "Bilateral Contracting in RTO Markets," report for APPA, April 2008, <http://appanet.org/files/PDFs/EMRISynapseBilateralsReport2008.pdf>; also, see the discussion of fixed-price contracts and supplier behavior in "Merger Analysis in Restructured Electricity Supply Industries: The Proposed PSEG and Exelon Merger," by Frank A. Wolak and Shaun D. McRae, November 2007, [ftp://zia.stanford.edu/pub/papers/pseg\\_exelon\\_merger.pdf](ftp://zia.stanford.edu/pub/papers/pseg_exelon_merger.pdf)

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APPA does not expect that increased reliance on longer-term bilateral contracts and owned generation will immediately produce lower prices. It is, however, likely to produce more stable and reasonable prices in the long run. Current shorter term power supply contracts of three years or less, such as those procured to provide SOS, include generation prices above the spot prices set in RTO markets because of the addition of ancillary, capacity, and transmission costs, plus multiple risk premiums.<sup>19</sup> Diversified LSE resource portfolios that include longer term contracts of 10, 20 or more years will likely minimize the need for some of these risk premiums because of the greater price stability and income stream provided to suppliers. Moreover, APPA's proposed price formation mechanism for the optimization market should better discipline spot prices, which in turn should discipline bilateral contract prices.

The use of longer term bilateral contracts also benefits developers of new generation, especially independent power producers (IPPs) whose access to capital depends on the assurance of a long-term revenue stream.<sup>20</sup> Capital-intensive renewable energy and other technologies have become increasingly dependent upon long-term contracts for financing, but RTO market structures do not provide necessary support for such contracts.

The recent upheaval in financial markets has only increased the need for long-term assured revenue streams to support new generation and other infrastructure investment. At a January 2009 FERC technical conference on credit and capital issues, IPP representatives emphasized the importance of long-term contracts in a tight credit market; with one stating that "current terms available in organized markets, such as five-year PPAs, are simply inadequate to attract the substantial debt and equity necessary to put steel in the ground."<sup>21</sup> Another speaker, a developer of renewable energy projects, stressed the necessity of long-term (15-year) power purchase contracts to support the financing of renewable projects.<sup>22</sup> A representative of Morgan

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<sup>19</sup> Testimony of Kenneth Rose, Ph.D., Independent Consultant, before the Pennsylvania Public Utility Commission, Nov. 6, 2008, [http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Tmy-Kenneth\\_Rose110608.pdf](http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Tmy-Kenneth_Rose110608.pdf), p. 8 – 11.

<sup>20</sup> Testimony given late in 2008 by an independent power producer in Pennsylvania, for example, in regard to project financing through long-term bilateral contracts stated: "While these asset development concepts may be well known, it isn't clear that they are easily reconcilable with the market model as it has evolved in PJM." Reply Comments to Nov. 6, 2008, Wholesale Energy Markets En Banc Hearing, Pennsylvania Public Utility Commission, Robert Frank, Reed Smith LLP, on behalf of LS Power Associates, Nov. 17, 2008, <http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Response-LSP111708.pdf>;

<sup>21</sup> Testimony of Bruce L. Levy, President, International Power America, Technical Conference, In the Matter of Credit and Capital Issues Affecting the Electric Power Industry, Docket Number AD09-2-000, Jan. 13, 2009. Transcript, p. 32. [http://elibrary.ferc.gov/idmws/file\\_list.asp?accession\\_num=20090113-4007](http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20090113-4007)

<sup>22</sup> Testimony of Michael Polsky, President & CEO, Invenergy LLC, FERC Technical Conference, Jan. 13, 2009, Transcript, p. 38.

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Stanley summed up the dilemma neatly, saying “I think the challenge that we have is that we’re trying to build long-term assets with short-term pricing, and that just doesn’t line up.”<sup>23</sup>

It is hard to ascertain the current status of bilateral contracting in RTO regions because of the way relevant data are reported. For example, PJM’s state of the market reports provide data on the percentage of power purchased through bilateral contracts, self-supply and spot markets.<sup>24</sup> In the *2007 State of the Market Report*, these data show that 96 percent of the power purchased in the real-time market was sold through bilateral contracts. But PJM does not break down these data according to the length of the contract or the pricing terms. Theoretically, a one week agreement to sell power at a price indexed directly to prices set in PJM’s spot market would be counted as a bilateral contract.

No data on bilateral contracts was found in the ISO New England and the Midwest ISO state of the market reports.<sup>25</sup> New York ISO reports only on “physical bilateral contracts,” which involve settlements with the New York ISO for transmission charges and between the parties privately for the commodity prices. These comprise about 40 percent of the day-ahead load in New York City and Long Island, 25 percent in East upstate, and 60 percent in West upstate.<sup>26</sup> Other types of bilateral arrangements are possible, but are not reported separately. As with PJM, there is no information provided on length or pricing terms.

Moreover, the RTO definition of a bilateral contract does not require that a contract be tied to associated capacity, such as a specific generating unit. Some of the bilateral contracts are sales from providers of standard offer service load to utilities, whose prices are often based on RTO spot market prices, with the addition of ancillary, capacity, and transmission costs, plus several risk premiums.<sup>27</sup> These SOS contracts need not be tied to specific

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<sup>23</sup> Testimony of Anthony Ianno, Managing Director, Morgan Stanley, FERC Technical Conference, Jan. 13, 2009, p. 50.

<sup>24</sup> *PJM State of the Market Report 2007*, pages 90-93, <http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2.pdf>. PJM also presents data for the day-ahead markets but not all bilateral contracts are included here, only those being offered into the day-ahead market to determine if there are better pricing terms available.

<sup>25</sup> An e-mail from ISO New England Customer Services, Dec. 24, 2008, in response to an APPA inquiry about bilateral contracting data states that “we do not report the bilateral contract or spot market activities.” No response has been received to date from MISO.

<sup>26</sup> *2007 State of the Market Report*, New York ISO, p. 59, 61, 62 [http://www.nyiso.com/public/webdocs/documents/market\\_advisor\\_reports/NYISO\\_2007\\_SOM\\_Final.pdf](http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf)

<sup>27</sup> Testimony of Kenneth Rose, Ph.D., Independent Consultant, before the Pennsylvania Public Utility Commission, November 6, 2008, [http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Ttmy-Kenneth\\_Rose110608.pdf](http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Ttmy-Kenneth_Rose110608.pdf), p. 8 – 11.

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generating units, and even if the supplier is delivering electrons from its own generating assets, prices are still tied to the spot markets, and not the costs of producing electricity from such units.<sup>28</sup>

In many other cases, the bilateral contracts used in RTO regions are standardized and the power product choices do not include capacity obligations or other provisions that would support new generation infrastructure. For example, the EEI/NEMA Master Agreement used in many eastern RTOs contains standardized language for product definitions, credit requirements and buyer/seller obligations.<sup>29</sup> A typical contract will specify a delivery point, price, quantity and time frame (for example, “20 MW delivered at [a selected trading hub] during on-peak hours in calendar year 2008”). These contracts also include “liquidated damages” or other liability provisions outlining financial responsibility for failure to perform under the terms of the contract. Under such agreements, a failure to supply power is not a breach of the agreement, but merely triggers the obligation on the part of the buyer to “cover” by obtaining replacement supplies at whatever price the buyer can obtain in the market at that time, with the seller paying the difference between the contract and market price. Such contracts may work well for financial parties interested in trading contracts, but are less than ideal for LSEs attempting to assemble a portfolio of power supply resources that can in fact be used to serve load.<sup>30</sup> Under APPA’s proposal, a truly vibrant bilateral market would rely less on standardized contracts developed primarily for trading purposes, and more on individually negotiated agreements sufficient to support the development of new generation and demand-side resources.

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<sup>28</sup> For example, see: Letter from Constellation Energy to President Miller and Speaker Busch, May 31, 2006, [http://www.sec.gov/Archives/edgar/data/1004440/000110465906038686/a06-12885\\_1ex99d1.html](http://www.sec.gov/Archives/edgar/data/1004440/000110465906038686/a06-12885_1ex99d1.html).

<sup>29</sup> The provisions of the EEI/NEMA Master Contract are available at [http://www.eei.org/industry\\_issues/legal\\_and\\_business\\_practices/master\\_contract](http://www.eei.org/industry_issues/legal_and_business_practices/master_contract).

<sup>30</sup> Many “net buyer” APPA members have found the standard EEI/NEMA contract terms and options unsuitable for their own power procurement needs. APPA has therefore developed a package of modifications to that contract (suitable for use by such buyers), available upon request or at <http://www.appanet.org/files/Word/SPIEGEL-%23212716v2-091107NewCoverSheetandAlternativeScheduleM%28APPAREv%29.DOC>.

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## VII. Market Power



Without new generation entry or a significant expansion in demand response and efficiency investments, generators may still have market power in the long-term bilateral contract markets, just as they now do in spot and locational capacity markets. This market power cannot be wished away. Generators are likely to attempt to exercise market power even if APPA's Competitive Market Plan is implemented, particularly in the early days of new market operations. Still, there are a number of reasons to believe that market power may become less of a problem (at least in the long run) and that markets would be more competitive under APPA's Plan:

- In current Day Two RTO markets, suppliers interact with each other frequently, since the RTO auctions clear on an hourly basis. This repeated interaction allows generators to observe the strategies of other bidders and respond in kind, encouraging coordinated bidding strategies and even tacit collusion.<sup>31</sup> Bilateral contracting processes, especially ones conducted under formal requests for proposals (RFPs) subject to public scrutiny, such as state-supervised procurements, would be less likely to be subject to such coordination or collusion.
- Bilateral contracting provides a greater opportunity for customers and suppliers to negotiate “customized” products to meet the supplier's and customer's particular needs, rather than being force-fit into a standardized form agreement.
- Bilateral contracting affords the customer the ability to select among different counter-party suppliers based on creditworthiness and other non-price factors relevant to performance over the long term.
- Compared to transactions in a spot or short-term market, long-term bilateral arrangements provide revenue stability that makes it possible for potential suppliers to finance capital-intensive generation projects at more reasonable capital costs, reducing barriers to entry into the generation market.
- Within a day-ahead or hour-ahead time frame, many suppliers have operational constraints (unit commitment, ramping, etc.) that keep them from being active bidders in RTO-run spot markets. Since there is more operational flexibility built into a long-term bilateral contract, a given buyer could have more potential counterparties.
- Because APPA's Plan would provide the transmission access and financial rights necessary for LSEs to have more and better power supply choices, including self-build and ownership of generation if they receive non-competitive supply offers, LSEs should in the long run have fewer problems with market power being exercised in the bilateral market.

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<sup>31</sup> Lester Lave, Jay Apt, and Seth Blumsack point out in *Deregulation/Restructuring, Where Should We Go from Here?* (2007) that experiments at Carnegie Mellon and Cornell “show that hourly auction markets are ideally designed to teach participants to manipulate the market to raise profit.” (p. 14)

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To incent participation in bilateral markets, APPA is also proposing that generators in each RTO region that pass the FERC's relevant market-based rate screens should be permitted to sell at market-based rates in bilateral forward markets. However, to guard against the exercise of generation market power, APPA is also proposing that FERC separately assess market-based rate applicants' generation market power in long-term power supply product markets.<sup>32</sup> To the extent that applicants do not pass such long-term market power screens, FERC would deny, rescind or appropriately condition their market-based rate authority as it relates to long-term product sales.

FERC must also ensure that MMUs are truly independent and have all of the resources necessary to perform their functions. As APPA recommended in *Consumers in Peril*, RTO market monitoring units (MMUs) should have the full cooperation of market participants in data gathering, including access to company-specific financial information and generating unit cost and operating data, as well as sufficient resources to carry out their duties. RTO MMUs should also monitor bilateral contract markets, and act on complaints regarding anticompetitive behavior by sellers or buyers in those markets. Moreover, MMU state of the market reports should provide much clearer and detailed information on bilateral contracts, indicating the length of such contracts and whether they are backed by the capacity of specific generating units or other appropriate arrangements.

APPA, however, remains quite concerned that due to the high concentration in wholesale power supply markets, exercise of generation market power in bilateral markets could indeed occur. For this reason, APPA proposes that the Federal Energy Regulatory Commission conduct a review of regional bilateral wholesale markets three years after implementation of APPA's Competitive Market Plan, to investigate whether market power remains a substantial concern. If the commission finds that market power exercise is a problem in bilateral markets in RTO regions, appropriate modifications should be made to FERC's market-based rate regulations and RTO market rules to address this problem.

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<sup>32</sup> APPA has petitioned for review of FERC's Order No. 679 series, in which FERC revised its procedures and standards for granting market-based rate authority, because FERC ruled that it need only assess generation market power in short-term power supply products. It instead relies entirely on the possibility of "new market entrants" to discipline prices for long-term power supply products. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (2007), at P 123. APPA's appeal has been docketed in the U.S. Court of Appeals for the Ninth Circuit as No. 08-72675.

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## VIII. Residual Short-Term and Imbalance Services: The Optimization Market

**B**ecause generator availability and customer demand cannot be perfectly predicted, and electricity cannot (yet) be stored economically in sufficiently large quantities, APPA’s proposal includes an RTO-operated residual “optimization” market. This market would allow for the co-optimization of offers by generators to sell excess energy and ancillary services, and for LSEs to obtain economy energy and clear imbalances. The optimization market also provides an opportunity for the sale of intermittent generation not committed under bilateral agreements and allows for the purchase of replacement power for intermittent generation not available at a given time.

APPA believes it is not in the interest of either buyers or sellers to place set limits on the percentage of load that can be met through the optimization market. Such limits reduce needed flexibility for LSEs, including their ability to purchase power from renewable intermittent resources, and restrict the flexibility of generators (especially intermittent generators) as well. APPA’s proposed RTO-run optimization market is designed to minimize the size of the spot market and encourage bilateral contracting for load not served by owned resources to the maximum extent possible without unduly restricting market participant options. Key design features of the optimization market include:

**1) Generator offers to sell into the optimization market would be limited to no more than their short-run marginal costs (SRMC).**

The SRMC includes only those costs that vary with the level of output, primarily fuels and operations, maintenance and administrative costs that vary with output. (For example, periodic inspection, replacement and repair of system components would be included because such maintenance depends upon the level of output.<sup>33</sup>) Opportunity costs would not be included in the calculation of the SRMC. Generators participating in RTO-run markets (whether the generators are inside the RTO footprint or exporting into the RTO territory) would be required to submit auditable SRMC information on the company’s entire portfolio of generation units to the MMU. These data would be available to the public on RTO Web sites. Any differences between supply offer curves submitted to the RTO optimization market and the cost data held by the MMU would need to be justified by the generator.<sup>34</sup> To facilitate

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<sup>33</sup>Section 5.2 of *A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs: 2003-2006* prepared by Serkan Bahceci, Julia Frayer, Amr Ibrahim, and Sanela Pecenkovic, London Economics International, February 2007, <http://www.appanet.org/files/PDFs/LEIRreport2012007.pdf>

<sup>34</sup>The existence of these differences would depend on the frequency with which generators submit cost data to RTOs. Very short-term swings in fuel prices, for example, might cause actual generator costs to deviate from the cost data held by the RTO. (One possible alternative would be to include some fluctuating fuel-specific index component in generator cost submissions.)



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demand response participation in these markets, demand response offers, would not be subject to the cost disclosure requirement; instead they would submit load-reduction demand curves or minimum price offers above which they would pledge to curtail a specified amount of load.

- 2) LSEs would be required to demonstrate to the RTO that they possess adequate amounts of generation capacity (either owned or contracted for) or demand-side resources to meet projected future needs.** This RTO-established resource adequacy requirement for individual LSEs would prevent them from “leaning” on the optimization market and avoiding contracts for or investments in generation and demand-side resources. Close coordination between regional and state-level policies and between RTOs and the state regulatory authorities in their footprints would be required to develop these resource requirements. The RTO would be responsible for determining the overall required level of reserves within its footprint, while state (or local) authorities would determine acceptable resource portfolios and other power supply attributes, e.g., contract terms, fuel mixes, and demand-side/generation ratios for their respective LSEs. The resource adequacy provisions of the APPA Plan are discussed further in Section IX.
- 3) A “must offer” requirement into the optimization market would apply to available resources, including resources not scheduled to serve loads under LSE ownership arrangements or bilateral agreements.** This requirement would limit opportunities for strategic withholding behavior. However, limited-run resources (e.g., generation units subject to air quality limitations on run times, and hydro units that must be operated for water use and recreational purposes as well as power supply production) would be exempted from the must offer requirement under most circumstances, due to the difficulties inherent in calculating the associated costs.<sup>35</sup> Participation of intermittent resources, of course, would also be subject to their availability. Owners of generation would be required to submit a schedule of planned maintenance or refueling outages to the RTO and to demonstrate compliance with the must offer requirement periodically with the RTO.

Another critical issue in designing a new RTO optimization market is the methodology used to establish prices. Current RTO markets use single-

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<sup>35</sup>If the RTO determined that limited-run resources had to be used during certain hours to ensure system reliability, it would have to make arrangements to pay such resources for running during the specific hours it required. Depending on the costs included in such payments, it might be most appropriate to uplift the revenues paid to such resources, rather than allowing them to set the single clearing price for the hours during which they were run at the direction of the RTO (rather than the choice of the owner of the resource).



clearing-price auctions, where the market-clearing price is paid to all generators offering a price below the highest accepted offer, irrespective of their individual offers. To avoid too dramatic a departure from current market design and in an effort to achieve a compromise, APPA's proposal would retain for the near future the single-clearing-price structure for use with the optimization market. Because of past issues with the single-clearing-price mechanism, however, APPA believes FERC must assess the operation of the revamped optimization market with this pricing mechanism no later than three years after the start of the market, to determine whether further market design changes are necessary to achieve just and reasonable rates, and therefore benefits to consumers.

The ability to earn short-term profits above SRMC could, at the margin, drive some lower-cost resources into the RTO's spot markets.<sup>36</sup> Simultaneously, the single-clearing-price auction would provide short-run and long-run price incentives for LSEs to develop longer-term portfolios of owned and contracted-for resources, to reduce reliance on the optimization market. However, the ability of generators to engage in bidding behavior intended to increase the single clearing price well above the marginal cost of even the clearing unit, to the mutual benefit of all generators being paid the clearing price, would be greatly reduced by the SRMC-based offer requirement.

Even more than short-term energy markets, ancillary services markets are particularly susceptible to the exercise of market power, in part because some services can be supplied only by a limited number of generators.<sup>37</sup> Given the cost-based offer and must-offer requirements in this proposal, the RTO can co-optimize supply offers across the energy and ancillary services markets. Under such a co-optimization, the RTO would simultaneously dispatch energy and ancillary services centrally, paying generators meeting the technical criteria and selected to supply ancillary services on a cost-reimbursable basis, if they are not dispatched.

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<sup>36</sup>In theory, at the margin the uniform-price auction structure would also provide incentives for investment in low-cost generation resources. However, this is unlikely to be a significant factor in APPA's proposed market redesign, in part because it is expected that this optimization market would be a small portion of overall electricity sales. Investment decisions would be driven primarily by the resource planning process.

<sup>37</sup>See, e.g., *2007 PJM State of the Market Report*, Section 6 at 276 ("The MMU concludes from these results that the PJM Regulation Market in 2007 was characterized by structural market power in 80 percent of the hours.") and 279 ("...[I]n 2007, as in 2006, the MMU cannot conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units. The MMU's reliance on estimates of regulation costs is one of the reasons that the MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time power mitigation."), available at: <http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2-sec6.pdf>.

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## IX. RTO Operations to Support Non-Discriminatory Transmission Access



Under APPA's proposal, RTOs would emphasize activities that support wholesale power supply markets — ensuring nondiscriminatory transmission access and managing congestion on the transmission grid, thus ensuring reliability. RTOs would continue to provide transmission service under open access transmission tariffs (OATTs), dispatch generating units in merit (lowest cost) order subject to system constraints, determine price differentials arising from congestion, and assist LSEs in hedging congestion.

In a market environment focused primarily on supporting long-term power supply arrangements, including both bilateral contracting and LSE-owned resources, RTOs would need to improve their management of transmission congestion. As explained in greater detail later in this paper, they would need to:

- Allocate financial transmission rights (FTRs) designed to support LSE power supply arrangements required to serve load.
- Collect data on bilateral contracts entered into by market participants transacting within the RTO footprint.
- Centrally dispatch generation in least-cost (merit) order based on actual costs of generation units submitted to the RTO.

These new proposed market functions are described in greater detail below.

### **Financial Transmission Rights and Long-Term Transmission Rights.**

RTOs would continue to offer OATT transmission service, but would implement policies to provide greater support to long-term power supply arrangements. RTOs would allocate annual FTRs directly to LSEs based upon a percentage of the LSE's peak load. Excess congestion revenue not paid to generators would then be given to the LSEs holding FTRs. LSEs with mid-year changes to loads or resources should be permitted to apply to the RTO for a change in their FTR allocations. Any remaining congestion revenues would be distributed to network and long-term firm transmission customers to ensure that market participants paying the embedded cost of the transmission system would receive the full economic value of their payments. Non-load-serving market participants would not be eligible to receive an allocation of FTRs, but LSEs would retain the right to resell their allocated FTRs if they chose.

RTOs would also allocate long-term transmission rights (LTTRs) to LSEs to support bilateral contracts or owned resources, with a priority

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for power supply arrangements of 10 years or longer.<sup>38</sup> These LTTRs would be paired with LSEs' power supply arrangements developed to comply with the RTO's resource adequacy requirements, and applicable state resource procurement requirements. However, without adequate transmission infrastructure in place during the term of the LTTR to support transmission service, the LTTRs might not provide a sufficient hedge to LSEs against congestion costs. Under the regulations promulgated in Order No. 2000, an RTO must possess the authority "for directing or arranging necessary transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory service."<sup>39</sup> Recent FERC decisions, however, have cast some doubt on this requirement, and hence on the potential revenue adequacy of LTTRs over their full term.<sup>40</sup> Such financial uncertainties in turn make it more difficult and costly to develop new generation resources. RTOs should be required to demonstrate that the data on projected loads and planned resources is incorporated into transmission system planning and expansion plans, to ensure that the RTO's transmission system is sufficiently robust to support LSE resource portfolios.

### **Collection of Bilateral Contract Data**

LSEs would submit their proposed bilateral contracts and owned generation resource arrangements to the RTO. The RTO would then subject these contracts and arrangements to a simultaneous feasibility test to determine whether they violate any transmission system constraints or overload any system equipment. This information, however, would not affect the dispatch, which would be done according to actual generator costs and transmission

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<sup>38</sup>LTTRs that have already been allocated by RTOs would be preserved. This LTTR proposal would necessitate revision of current FERC LTTR guidelines to require that such rights be allocated preferentially to LSEs with contracts or supply from owned resources to serve load of 10 years or longer. In Order No. 681, issued in Docket No. RM06-8-000, Long-Term Firm Transmission Rights in Organized Electricity Markets, FERC decided to give a preference to all LSEs in the granting of LTTRs, rather than only those with long-term power supply arrangements (116 FERC ¶ 61,077, issued July 20, 2006, at PP 318-330). However, FPA § 217(b)(4) states that FERC must use its FPA authorities to "enable load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs." Hence, such a preference for long-term power supply arrangements has explicit support in the FPA itself. EPAct '05 Implementation: Is FERC In Full Compliance?," Jay Morrison, *Energy Law Journal*, Volume 28, No. 2 (2007), <http://www.eba-net.org/docs/elj282/EPAct.pdf>.

<sup>39</sup>18 C.F.R. § 35.34(k)(7).

<sup>40</sup>Midwest Independent Transmission System Operator Inc., 125 FERC ¶ 61,061, P 34 (2008) ("While we recognize that the Midwest ISO has the obligation to facilitate generation interconnections and expansion planning, it cannot force utilities to build capacity. The Midwest ISO therefore cannot be required to build sufficient transmission capacity to ensure deliverability of all resources for their useful life."); Midwest Independent Transmission System Operator Inc., 125 FERC ¶ 61,062, P 162 (2008) ("Also, while the Midwest ISO is obligated to facilitate generation interconnection and expansion planning, it cannot force utilities to build capacity and therefore it cannot assure deliverability for all projects' useful lives.").



constraints and would be performed separate from the terms of the contracts. Bilateral contracts would act as financial arrangements determining the payment streams between buyers and sellers. The feasibility test would, however, feed into determinations of FTRs and plans for transmission expansions and upgrades.

Guidelines for allocating FTRs and LTTRs would need to be established in the event that all of the power supply arrangements submitted to the RTO during a particular time window cannot pass the feasibility test. For example, priority could be given to LSE power supply arrangements with longer terms, or arrangements that LSEs enter into to meet their service obligations, as discussed above. The RTO should include such contracts and arrangements in its regional transmission plan, and ensure that sufficient transmission facilities are constructed as needed to support them.

## **Centralized Dispatch**

The RTO would centrally dispatch all generation within its footprint, regardless of whether it is an owned resource, scheduled under a bilateral contract, or offered to the optimization market. The RTO would use a cost-based security-constrained economic dispatch formulation (similar to how current RTOs operate, except that the RTO would be using actual cost data, rather than submitted bids).<sup>41</sup> The terms of the bilateral contracts would reflect the financial arrangements to be settled between the buyers and sellers, and would be settled separately from the actual dispatch. Generators would be paid based on prices negotiated through the bilateral contracts, or set in the optimization market, as applicable.

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<sup>41</sup> Generators would still be permitted to designate a zero cost for dispatch purposes if they need to dispatch owned resources, meet contractual obligations or keep a unit running for morning ramp-up.

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## X. Renewable Energy

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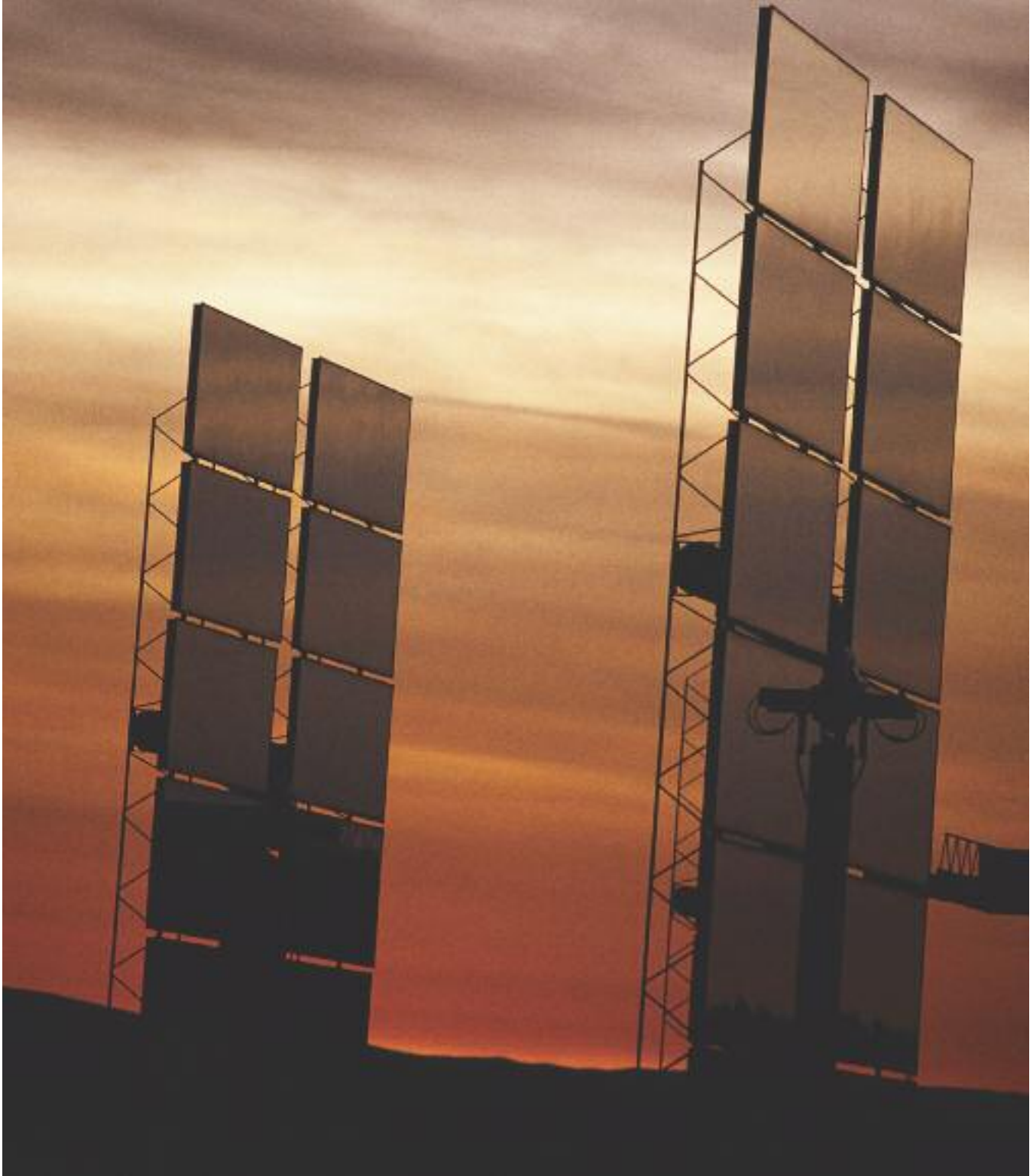
any states are implementing renewable portfolio standards (RPS) or goals under which LSEs are required to provide a portion of their sales or capacity requirements from renewable or low-emissions generation sources, or from energy efficiency measures. Moreover, proposals are being made in Congress to enact a national renewable electricity standard (RES). From the point of view of the RTO, such requirements effectively amount to giving alternative energy sources some level of priority in the dispatch mix. Some alternative energy sources, such as biomass or geothermal, can simply participate in the bilateral market along with traditional fossil and nuclear generators. Intermittent renewable generation sources such as wind and solar, however, can be more difficult to integrate into RTO dispatch mixes, since there may be a higher risk of unavailability during a particular time interval.

APPA designed its proposed market reform plan to be compatible with such renewable energy goals. Rather than being set by the “market,” the penetration level of these intermittent renewable generation sources will likely be set based on policy considerations determined by regulators, governors and legislatures. Operationally, the RTO would simply have to schedule these resources when they are available (either directly or through individual LSE schedules), possibly backing down other sources of generation in the process (this would only become an issue when intermittent generation resources reach a significant penetration level within an operating area). Since intermittent resources often are not available at the full contracted amount in a particular hour, they must be “firmed up” in some manner. One way to do this would be to require LSEs scheduling wind or solar resources to develop portfolios of resources that include appropriate backup capacity (e.g., natural gas or hydroelectric power).<sup>42</sup> These portfolios could be determined by the states in the power supply planning processes described later. Alternatively LSEs would simply purchase adequate operating reserves through the ancillary services market to support their intermittent resources.<sup>43</sup> Since this could involve large amounts of operating reserves, the RTO and state-level regulators would need to cooperatively determine regional solutions for handling intermittent resources as part of the resource adequacy and transmission planning processes.

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<sup>42</sup> This arrangement has been explored by C.L. Anderson and J. Cardell, 2008, “Reducing the Variability of Wind Power Generation for Participation in Day-Ahead Markets,” Proc. of the 41st Hawaii International Conference on System Sciences, Waikoloa, Hawaii.

<sup>43</sup> Regarding increased use of wind energy, the Department of Energy notes that “the imbalances can be offset with adequate operating reserves (which include quick-start and spinning reserves) that can rapidly respond to changes in wind output.” *20% Wind Energy by 2030*, Appendix B, US Department of Energy, Office of Renewable Energy and Energy Efficiency, May 2008, available at: [http://www.20percentwind.org/20percent\\_wind\\_energy\\_report\\_05-11-08\\_wk.pdf](http://www.20percentwind.org/20percent_wind_energy_report_05-11-08_wk.pdf)



Distributed (local) generation, energy storage and micro-grids are emerging alternative energy sources that may not be included in current RPSs but that may benefit consumers when compared to purchasing energy from the grid. During times of peak or rapidly fluctuating demand, local generation or energy storage may also impart significant benefits to the grid as a whole, relieving strain on transmission and generation facilities. The RTO would need to develop tariff provisions accommodating LSE use of these distributed generation sources as a way to meet resource adequacy requirements.

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## XI. Resource Adequacy and Planning



PPA's Competitive Market Plan does not include any explicit RTO-administered payments or markets for generation capacity. Studies of the PJM and NY ISO capacity markets reveal that these markets have generated payments to generators far in excess of what would be needed to cover the actual costs of constructing new capacity, with only limited success in addressing reliability concerns.<sup>44</sup> APPA believes it would be far better to use a combination of resource adequacy requirements, a comprehensive transmission planning process, and long-term power supply and demand response arrangements to ensure adequate supply resources in RTO regions in future years.

Overall RTO-established resource adequacy standards applicable to all LSEs are an important feature of the APPA proposal.<sup>45</sup> These standards may have to be tailored by the RTO for specific subregions within its footprint, depending on transmission constraints and other factors. APPA is aware that there are jurisdictional disputes over the exact level and nature of RTO-set resource adequacy requirements. Generation adequacy requirements traditionally have been the purview of state utility regulators and Regional Reliability Councils. An increased RTO/federal role would require coordination and cooperation among state regulators, RTOs, and FERC in establishing and approving regional resource adequacy plans. This section lays out in more detail the resource adequacy provisions of the Competitive Market Plan. Appendix A of this paper provides a background discussion on the current resource adequacy provisions in restructured markets.

APPA's proposal would establish a multi-state regional process to develop needed RTO-wide resource adequacy requirements under agreed-upon policy goals. States would then implement procurement processes to ensure that state-regulated (IOU) LSEs obtain a diversified portfolio of power supply and demand-side resources of varying lengths and terms that will assist in meeting the RTO-wide resource adequacy requirements.<sup>46</sup> States and LSEs could also agree to pool their LSEs' respective resource needs for procurement purposes, rather than having each individual state or LSE act on its own. Such procurement processes would greatly benefit new

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<sup>44</sup> See Mount (2007) and Wilson (2008).

<sup>45</sup> These standards would be applied to a number of years going forward, with the precise time frame to be determined.

<sup>46</sup> Public power utilities in RTO regions, because they have retained their obligation to serve retail customers, already develop and implement such resource adequacy plans, under the supervision of their local governing bodies. They conduct periodic generation procurements, assessing "buy v. build" generation options, as well as the use of demand response and energy efficiency measures to reduce demand, in lieu of securing additional generation. Because they are not-for-profit and do not earn a return on owned generation assets as investor-owned utilities do, they approach these decisions from a consumer-benefit perspective. For these reasons, public power utilities should continue to procure their resources under their own plans, unless they choose to opt into a larger state procurement process.

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suppliers of generation, demand response and energy efficiency technologies by providing a revenue stream needed to support long-term financing. Sufficient safeguards also need to be included in the selection process to ensure that third-party suppliers get fair and equitable consideration of their offers and proposed projects.<sup>47</sup>

Demand response resources should be fully considered in developing LSE resource portfolios.<sup>48</sup> Energy efficiency investments as an alternative to generation resource obligations must also be fully considered. Given that utility LSEs already provide retail service to end use customers, the LSE may be the lowest-cost supplier of demand response or efficiency services. But as part of the regional procurement process, third-party demand response providers could bid to provide such services to LSEs. Because demand-side resources may in fact be the lowest-price supply options (in addition to being the lowest carbon-emitting options), they should be an important part of the resource portfolio for the region and for LSEs.

State requirements and policy preferences for fuel diversity (such as state RPS and energy efficiency goals, and state/regional carbon mitigation regimes) should be honored in developing LSE resource portfolios. The RTO would have to ensure, however, that the LSE resource portfolios developed are, taken as a whole, both technically feasible and operationally reliable.<sup>49</sup> (For example, an LSE's 50 percent wind portfolio might exceed an applicable state RPS requirement, but it would not necessarily be adequate or reliable from the RTO's standpoint unless sufficient backup supply/storage were available.)

Another important issue in constructing competitive procurements for state-

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<sup>47</sup> State competitive procurement "best practices" are discussed at length in a 2008 paper prepared for the Collaborative on Competitive Procurements between FERC and the National Association of Regulatory Utility Commissioners (NARUC). "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," Susan Tierney and Todd Schatzki, July 2008, available at: <http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf>

<sup>48</sup> Non-performance of demand response resources presents some risks to the RTO, since large amounts of demand response that did not materialize when called upon would have a similar adverse impact on system operations as the sudden loss of a large amount of intermittent generation. APPA accordingly supports the right of the RTO to impose technical requirements and verification criteria on demand response resources to ensure that these resources do perform as intended, if they are to be counted in an LSE's resource portfolio. Such requirements and criteria, however, must not discriminate against demand response and in favor of other resources in the portfolio.

<sup>49</sup> One issue that may arise is whether to allow "liquidated damages" contracts to be included in an LSE's resource portfolio, and to count towards meeting the RTO's resource adequacy requirement. Although not directly linked to a specific generating unit, such contracts should be allowed at least for a transitional period, so that LSEs may continue to use existing agreements in their portfolios to meet the relevant standards in the short run, and transition to qualifying power supply arrangements.

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regulated LSEs is to determine who will conduct the solicitation for bids and evaluate the submitted bids. The details of current programs vary from state to state, but in general, current state auctions or bidding programs for determining who will supply retail customers are either conducted by the state commission directly (for example, Maine or New Jersey) or by the regulated utility (that is, the LSE) under the supervision and oversight of its state commission (for example, Delaware, Maryland, or Massachusetts).<sup>50</sup> An independent third party designated by the state or LSE (with state approval) could also administer the procurement process.

Once the selection of the resources is determined, contractual arrangements with the suppliers or providers of the resources (including arrangements for selected self-build options) would be made. The objective would be for LSEs to have a diversified portfolio of resources, including long-term supply commitments that provide customers electricity at a relatively stable and reasonable price, while assuring suppliers a steady revenue stream that can support financing of new resources. APPA's intention here is to recapture the benefits to consumers of the long-term commitments and obligations that regulated utilities had under traditional cost-based regulation to provide reliable electricity at a just and reasonable price, while at the same time taking full advantage of wholesale competitive options to discipline prices and suppliers.

APPA's plan has the following advantages over the current system:

- The planning and procurement process can provide a means for meeting individual state policy goals in a regional process (such as renewable portfolio standards or demand management programs).
- Progress can be monitored as the process moves through the planning and procurement stages and any necessary adjustments can be made along the way. Accountability for LSE resource adequacy is left primarily to the states and LSEs.
- This method allows the resource planning and procurement process to be conducted by the parties involved (LSEs and states), after the RTO-wide determination is made on overall resource adequacy requirements.
- The use of competitive procurement processes to make the actual resource selections allows for competitive forces to provide price discipline on wholesale resource decisions.
- Increased reliance on longer-term supply commitments should reduce the supply adequacy problems caused by overreliance on short-term RTO-run energy markets and the overpayments for new capacity produced by some RTO-run locational capacity markets.

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<sup>50</sup> If the regulated utility is to take the lead, this should be done under the close supervision of the relevant state commission.

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## XII. Transmission Planning



A parallel effort to create a stronger transmission planning, siting and construction process would also be necessary to implement APPA's proposed market reforms. A critical and yet to be resolved issue is transmission congestion that remains in key pockets of regional transmission systems. Relying on the transmission owner members of RTOs themselves to build transmission facilities in response to congestion-based "pricing signals" in Day Two RTOs generally has not worked well. When transmission owners in RTO regions have undertaken new projects, they have insisted on (and generally obtained from FERC) very generous transmission rate incentives that unduly increase retail electric rates to consumers.

While Order No. 890 contains provisions intended to improve regional transmission planning, it is too early to judge the success of its implementation. What is lacking in current RTO transmission planning processes, however, is a clear linkage between LSEs' long-term resource commitments and long-term transmission availability (in the form of viable LTTRs that would fully hedge associated transmission congestion costs). As discussed earlier, not only does the Competitive Market Plan recommend that LSEs with long-term power supply arrangements be given priority in allocating LTTRs/FTRs, but also that LSEs' long-term resource portfolio choices feed directly into RTO transmission planning. Priority should be given to transmission infrastructure needed to support such resource arrangements.

RTO transmission planning processes require cooperation among the RTO's transmission owners to construct the transmission facilities needed to serve the present and future needs of the entire region. Incentives to do so, however, are muddled by thorny cost allocation issues, the prospect of tough siting battles and generation/transmission cross-ownership.

A related problem is that of transmission constraints that affect resource decisions. For example, if an LSE wishes to contract for long-term power supplies from a generation unit at a specific location in the RTO's footprint, but there are transmission constraints between the proposed resource and the LSE's load, how should this be handled? Ultimately, the RTO would need legal support from state authorities and FERC for sufficient transmission upgrades to support LSEs' long-term power supply choices, as incorporated into their resource portfolios.

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## XIII. Transition Issues



It has now been almost a decade since the Federal Energy Regulatory Commission issued Order No. 2000. The course of RTO market development since that time has been difficult and controversial. The transition period to implement needed RTO market reforms is also likely to be prolonged and contentious, with bumps in the road and the possible need for mid-course corrections.

For market participants that have made investments and resource procurement decisions under existing market structures that would be undergoing changes, implementation of the APPA Plan would likely require mechanisms to avoid or at least minimize economic injury during a substantial transition phase. For example, owners of capacity receiving payments under an RTO-run locational capacity markets may require a phasing out of such payments over the remaining term of the RTO's forward market auction windows, even as resource adequacy requirements for LSEs are phased in.

APPA's proposed market redesign, which couples bilateral contracts and resource ownership with centralized dispatch, is compatible with FTRs, as are current RTO markets. Because this plan would not reinstitute physical transmission rights, the transition is less difficult. The transition might, however, still impact the FTR holdings of some market participants. Since real-time dispatch would be based strictly on costs rather than on market-based offers, the pattern of power flows in the transmission network will change to the extent that past market-based supply offers have been different than costs.

Many aspects of the APPA Plan, such as the requirement for submission of short-run marginal costs for dispatch and optimization markets, may require FERC proceedings to work out the details, and likely would prove contentious. The recommendations for state-supervised procurement processes for state-regulated LSEs will likely entail state-level regulatory changes, or even new legislation. But even before the completion of the transition, steps taken to implement the Plan's features could have near-term positive impacts on financing availability, by increasing the confidence in electricity markets on the part of lenders and investors. Moreover, reform of the RTOs' short-term markets alone might have a salutary effect on the bilateral markets, providing an incentive for generators to offer more customized and attractive products and to bargain in a more meaningful fashion with prospective buyers.

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## XIV. Conclusion



Implementation of APPA's Competitive Market Plan would take a substantial period of time. Many thorny transition issues would have to be resolved. There are substantial institutional and political obstacles as well. Differences in market design details among RTOs and differences in state retail regulatory regimes would require customized application of APPA's Plan in each RTO. Hence, APPA suggests its Plan as one path to reach necessary long-term goals for the electric utility industry, including the development of new financial arrangements necessary to support new resource development in the wake of the 2008 financial crisis.

Above all, APPA intends by proposing its Plan to start a rational debate about the future of RTO markets—a debate the industry badly needs to have. RTO-run centralized power supply markets are not working as originally envisioned. The resulting dysfunction has had substantial negative implications for the economy, reliability and the cost of retail electric service in RTO regions. The industry needs to start talking about necessary reforms. Before this dialogue can commence, however, those who advocate “competition” in wholesale electric markets have to acknowledge the current substantial problems with RTO-run centralized power markets. The debate should no longer be about who can best massage the statistics or whether it is more virtuous to support “competition” or “regulation.” Instead, the industry must work together to develop a regulatory regime for electricity markets in RTO regions that will truly benefit consumers, businesses and the environment. Unless the electric utility industry and its regulators can agree on a market design and regulatory paradigm that fairly balances the interests of both load and generation, the industry will be condemned to continued upheaval.

## Division of Responsibilities for Resource Adequacy in Current RTO Market Structures



The current RTO market structure has not resulted in a robust set of resources to meet future projected demand. Nor has it produced sufficient diversity of fuel supply or low-carbon energy development. In short, sole reliance on “market” forces to determine resource amounts and fuel mixes is not likely to achieve such goals. Long-term planning and better-supervised resource procurement is therefore needed for resource adequacy of supply and demand resources and transmission. Achievement of such goals is critical to the RTO’s ability to support longer term power supply arrangements, operate short-term energy markets, provide transmission service and ancillary services, and carry out other RTO functions. This section outlines an alternative resource adequacy procedure as part of the Competitive Market Plan.

### Resource adequacy under cost-based regulation

Under a cost-of-service based regulatory framework, states and utilities developed and used procedures for decades to ensure that sufficient resources were available to meet projected customer demand. As the regulatory system evolved over time, utilities had the responsibility to plan and maintain the system to reliably meet customer demand.<sup>51</sup> Since utilities were generally the sole providers of electricity to customers (and were usually granted exclusive franchises to operate in their service territory), they were regulated and provided sufficient funds to operate, maintain and expand their systems, and to earn a return on their investment. States generally had the authority to regulate retail rates of their jurisdictional utilities, and approved prudent costs for new generation that were deemed used and useful for customers.

Table 1 summarizes resource acquisition under cost-based vertically integrated regulation. Utilities generally took the responsibility and did the planning to acquire new resources, and had both the incentive and the obligation to do so. FERC’s authority was limited to regulation of “sales for resale” (wholesale sales) and wholesale transmission service—having only limited impact on the resource choices of vertically integrated utilities (except for the siting of hydroelectric generation facilities).

In general, this arrangement worked well enough to build a great deal of the infrastructure we still use today. It was not perfect, of course. Utilities were sometimes provided incentives to over-capitalize or over-build their systems.<sup>52</sup> To offset that incentive, states developed the prudent

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<sup>51</sup> Many states still use this form of cost-of-service or “traditional” regulation, and likely will continue to use it for the foreseeable future. However, some states in RTO areas, and particularly states with retail access, have either modified how utilities or other LSEs acquire new resources or have responsibility for new resources shifted from primarily utilities to the region or RTO markets.

**Table 1.**  
**Resource adequacy under cost-of-service regulation**

	Load Serving Entities (utilities)	RTO	FERC	States
Responsibility	X			
Authority				X
Incentive	X			
Planning	X			

investment and used and useful tests. Application of these tests added to the administrative costs and may have caused some reluctance on the part of state-regulated utilities to add capacity. However, from an overall pragmatic standpoint, this system supported the construction and maintenance of a reliable and affordable system, much of which we still rely on to this day.<sup>53</sup>

### **Resource adequacy with an RTO structure**

Under the current RTO system, responsibility, authority, and planning have become more fragmented among federal, state and non-governmental RTO authorities. RTOs plan for the needed resources for the system (on a system-wide basis), but they do not build anything themselves and have been highly reluctant to force anyone else to do so. States authorize projects within their jurisdiction, approving siting of generation and transmission facilities, with possible FERC preemption for transmission projects sited in DOE-designated “national interest transmission corridors.” FERC, even with its expanded role under restructuring,<sup>54</sup> can only provide “incentives,” but does not order (or has not tried to order) specific generation or transmission projects. Neither FERC nor the states usually become directly involved in constructing projects. Generators, left to their own choice, will choose technologies and fuels that make the most economic sense from their standpoint and investment time frame, which does not necessarily match the needs of the overall regional system. This has meant that mostly natural gas combined-cycle units have been built and only a few base load plants are being completed. A generation resource mix with an

<sup>52</sup> This includes the Averch-Johnson effect, “goldplating,” and “ratebase padding.”

<sup>53</sup> Perhaps one of the most famous failures of this system, one that helped usher in industry restructuring, was the nuclear power plant cost overruns of the 1970s and 1980s. However, it could be argued that this was simply the result of poor regulation, not a failure of the system itself.

<sup>54</sup> As wholesale and retail restructuring has developed since the late 1980s, the amount of electricity that passes through some type of FERC-regulated control has increased. This has occurred as a result of both federal and some state legislation and regulatory changes, such as divestiture of IOU generation.

overreliance on one fuel may be inadequate for reliability purposes.<sup>55</sup>

As can be seen in Table 2, under an RTO system, responsibility, authority, incentive, and planning are divided among LSEs, RTOs, FERC, and states. The misalignment of responsibility with incentive and planning, in particular, creates a challenge that has been addressed in cumbersome and costly ways. For example, RTOs have created forward capacity markets to provide incentives to provide new generation capacity and demand response. The incentive to build has shifted from utilities to IPPs and others willing to take on the financial risk. However, these generators have no responsibility to maintain system reliability, have no obligation to customers beyond their specific contract arrangements, or any system planning requirements.

**Table 2.**  
**Resource adequacy within RTO footprint**

	Load Serving Entities (utilities)	RTO	FERC	States
Responsibility	X			
Authority			*	X
Incentive	**			
Planning		X		

\* Limited backstop transmission siting authority for projects sited in “national interest transmission corridors,” as designated by DOE and siting authority for hydroelectric facilities.

\*\*Only for remaining vertically integrated utilities with supply obligation to retail customers.

A similar misalignment has occurred with transmission planning and expansion. Under cost-based regulation, responsibility for grid reliability was clearly with the utility. If there were any interruptions of service, the utility was directly responsible. But this responsibility has now been shifted to RTOs. RTOs do the planning, but they do not build any transmission facilities and generally have not required their member transmission owners to do so. FERC can authorize recovery of transmission project costs if an entity proposes to build new transmission or expand its existing transmission system (including rate incentives), but has not tried to order such entities to do so. States approve the siting of new transmission lines and (in many cases) approve significant expansion of existing lines, but only rarely have required a transmission owner to expand its system. Moreover, the incentive for transmission owners that also own generation is often to not expand their facilities because it will lower prices for their generation.

<sup>55</sup> In 2007, the North American Electric Reliability Corp. (NERC) noted that “high reliance on natural gas in some areas of the U.S. must be properly managed to reduce the risk of supply and delivery interruptions.” In its 2008 report, NERC noted that “natural gas delivery remains a concern.” (NERC, *2008 Long-Term Reliability Assessment*, October 2008, p.5.)



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