

Power Supply Procurement in Retail Choice States

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Background: Beginning in the late 1990s, several states implemented programs allowing retail customers to choose their electric power supplier. Legislatures, governors, and state regulatory commissions established different mechanisms to manage the transition from traditional regulation to retail choice. In most states, rate freezes and reductions were put into place for a specified period of time. Many states also required utility divestiture of generation. Standard Offer Service (SOS) or Provider of Last Resort (POLR) plans were established to provide power supply for those customers that remained with their regulated utility.

Over the past couple of years, when transition periods ended for most distribution utilities in retail choice states, these utilities were still providing standard offer service to most of their residential customers. Since many distribution utilities no longer owned generating facilities, states had to establish procedures for the utilities to obtain power from the market to serve their customers. Utilities with transition periods ending in 2006 were faced with very high power supply prices, which resulted in large rate increases for their customers. As a result, many states implemented proceedings to examine the future of retail choice and to consider power procurement options. These proceedings have included debate and discussion on long-term contracts, utility ownership of generation, energy efficiency programs and other related issues. The following summary highlights the arguments made by various industry participants on these issues, as well as some of the final rules and regulations implemented by select states to address the future of power supply procurement.

The summary is followed by a description of recent investigations and reports on power supply procurement in various retail choice states.

Long-Term Contracts

A major issue is contract length for power supply agreements (PSAs). The debate centers on whether long-term contracts should be encouraged. Those who argue in favor of long-term contracts focus on price stability and electric reliability. The Connecticut Office of Consumer Counsel believes that intermediate and long-term contracts for power from new resources in the state would create incentives for new energy supply and capacity, which in turn would lead to lower market prices and reduced potential for generators to exercise market power. The New York State Bar Association also contends that long-term PSAs will lead to capacity additions; however, they caution that state commissions need to guarantee cost recovery.

Other groups believe that long-term contracts should be part of an overall approach to power supply procurement. The Office of People's Counsel (OPC) in Maryland suggests that long-term contracts provide greater price stability and should be considered as part of the procurement mix. OPC also suggests that more than one type and duration of supply product should be included in the portfolio.

Though most organizations think that long-term contracts should, at the very least, be part of the procurement mix, others oppose them. The Retail Energy Supply Association, testifying before the Connecticut Department of Utility Control, provides several reasons why they should not be used for standard service:

- The contracts could wind up exceeding market prices, causing customers to pay higher prices than they would under market conditions.
- If market prices exceed contract prices, customers are exposed to a rate shock upon the termination of the contract.
- Long-term contracts undermine competition.
- Long-term contracts undermine energy efficiency programs by sending inaccurate price signals to customers that prevent them from cutting back on energy usage.
- Long-term contracts with wholesale suppliers include risk premiums, and these premiums tend to be larger as the length of the contract increases.

The Bangor Hydro-Electric Company (Maine) believes that long-term contracts would transfer risk to transmission and distribution companies. Financial companies could treat these contracts as imputed debt, resulting in a higher cost of capital that will ultimately be passed on to customers.

Portfolio management and procurement strategies

Many parties have emphasized the need to create a diverse portfolio – either in terms of contract length, fuel mix, or energy efficiency and renewable capacity. Allegheny Energy in Pennsylvania recommends using multiple procurement methods in the state. Supply contract lengths can be different depending on customer class. The goal is to find a balancing point that reduces price volatility, while also ensuring some measure of price responsiveness. The Office of Consumer Advocate in Pennsylvania similarly argues against using a single procurement method.

The Maryland Public Service Commission received several different proposals for procuring power for SOS customers. The recommendations ranged from monthly bidding where 100 percent of the load would be procured via monthly contracts to rolling three year contracts where 33 percent of the SOS load would be up for bid every year.

Some parties are reluctant to rely on the markets to promote portfolio diversity. Morgan Stanley argues that the state of Connecticut will need to have some type of directed payment to facilitate portfolio diversity. This payment will go to generators who maintain an uneconomic resource mix. Connecticut Light and Power Company argues against reliance on the market, and suggests that an integrated planning process would be the best method for achieving both fuel diversity and system reliability.

In regard to portfolio management, a report on Delaware's electricity future suggested that this could be left either to utilities or to some state-created entity, such as a state energy authority. This power authority could directly serve all SOS customers or it could be a bidder offering supply to another portfolio manager. The New York Bar Association also discusses the creation of a special purpose entity to finance new generation capacity.

Not all are opposed to a market approach. The Maine Public Utility Commission prefers a market approach to procure standard offer supply. The Commission would solicit competitive bids and leave the burden of portfolio management to the suppliers.

Utility Ownership of Generation

Some entities urge utility ownership of generation. The Connecticut Office of Consumer Counsel states that utility ownership of generation would mitigate horizontal market power in energy and capacity markets, and that it would also promote fuel diversification, rate stabilization, and reliability.

Maine utilities also urge utility ownership of generation. Bangor Hydro-Electric Company argues that if transmission and distribution utilities are to be required to obtain energy supply for customers, then these utilities should be permitted to “put iron in the ground” and develop their own facilities. Central Maine Power Company also argues on behalf of utility ownership of generation, noting that regulated utilities typically can secure long-term financing for large capital projects on better terms than non-utility generators can.

Under Michigan’s 21st Century Plan, utilities would be allowed to build their own generation under traditional regulation or could choose an alternative option which involves the Public Service Commission granting a Certificate of Need to utilities that have submitted an integrated resource plan. Issuance of the Certificate of Need would preclude any challenge to the plant’s usefulness.

Others argue against utility ownership of generation, citing concerns that it would hamper retail choice programs. The Maryland Energy Administration notes that if utilities make large investments in new generation, they would need assurance of cost recovery. This would result in either limitations to retail choice programs or some form of stranded cost recovery. The Retail Energy Suppliers Association argues that utility ownership of generation would reestablish the risks that customers and utilities faced prior to deregulation.

Energy Efficiency

Another way to deal with power procurement problems is to lessen the demand for electricity. Energy efficiency programs are designed to affect consumer behavior and get them to reduce energy consumption. Several states are emphasizing energy efficiency and are implementing or proposing programs related to energy efficiency.

Connecticut Governor Jodi Rell has called for a campaign to teach residential and commercial customers about energy efficiency programs and renewable energy. The Pennsylvania Public Utilities Commission is also creating a \$5 million education program aimed at consumers. The Energy Association of Pennsylvania touts the success of the Low Income Usage Reduction Program (LIURP) in reducing energy usage.

The Michigan 21st Century Plan offers many energy efficiency recommendations. The Plan proposes the creation of a program to promote energy efficiency, funded by a direct

uniform charge on customers' bills, to be administered by an independent third party. The Plan also suggests that utilities could implement time-of-use rates as a means to get customers to reduce energy usage at times of peak demand.

The Massachusetts Division of Energy Resources (now the Department of Public Utilities) argues for dynamic pricing and suggests four possibilities: real time pricing, time-of-use pricing, critical peak pricing, and variable peak pricing. These are all designed to reduce peak energy usage.

State proceedings

The following state summaries highlight specific issues and resolutions brought forward in nine deregulated states as regulatory and other governmental bodies have examined the future of power supply procurement in their states.

Power Supply Procurement: Connecticut

Background: Electric rates have increased substantially in Connecticut, largely as a result of the increased market price of power.¹ The Connecticut Department of Public Utility Control (DPUC) opened a proceeding on whether the state should continue to rely on the market to set rates and to develop new generation, or whether some type of non-market-based solution should be considered.

Recommendations from the proceeding: Connecticut Light and Power Company (CLPC), the Office of Consumer Counsel (OCC), the Retail Energy Supply Association (RESA), Morgan Stanley Capital Group Inc., and Levitan & Associates filed comments before DPUC related to its review of standard service and supplier of last resort service (SOLR). CLPC, OCC, and Levin & Associates supported the notion of using long-term contracts to procure power, while RESA opposed this idea. All gave some amount of qualified support for Contracts for Differences (CfD) as a way to hedge price increases.

The governor also submitted her own energy plan, calling for energy efficiency incentives, increased reliance on renewable resources, and the creation of a new state Department of Energy.²

Specific Comments

Morgan Stanley:³ The state will not be able to rely on the market to promote a fuel-diverse portfolio. Some type of directed payment will be needed to facilitate portfolio diversity. This payment will go to generators who maintain an uneconomic resource mix.

Morgan Stanley sees no difference between physical and financial contracts in terms of promoting system reliability. In order to achieve rate stability, Morgan Stanley suggests a program of regular procurement akin to New Jersey's rolling auction system where only part of the total supply requirement is purchased at a given time. This system is also the best way to de-link current natural gas prices from retail electricity prices because any given purchase would make up only a portion of the rate structure. Morgan Stanley is critical of other ideas for de-linking natural gas and electricity prices:

Some parties advocate contracting directly with plants using cheaper fuels, in the mistaken belief that such contracts would be at rates closely tied to the cost of fuel for that plant. However, this belief fails to explain why a generator would sign such a contract and forego the opportunity to sell into the market at prices set by the marginal

¹ Comments of the Connecticut Light and Power Company before the State of Connecticut Department of Public Utility Control, Docket No. 06-01-08PH01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan approval*, January 30, 2007.

² Governor M. Jodi Rell's State Budget Address, February 7, 2007, accessed at <http://www.ct.gov/governorrell/cwp/view.asp?A=2791&Q=332098&pp=12&n=1>.

³ Comments of Morgan Stanley Capital Group before the State of Connecticut Department of Public Utility Control, Docket No. 06-01-08PH01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan approval*, January 30, 2007.

gas unit, absent some form of administratively determined, out-of-market payment as an incentive.⁴

Morgan Stanley also states that new generation will be built only when developers are confident that future revenue streams will provide an adequate return on investment.

Connecticut Light and Power Company:⁵ CLPC argues that utilities need to have the ability – which they currently lack – to enter into long-term contracts and to use hedges in order to serve load. The utility also argues that the market system does not necessarily promote fuel diversity, and an integrated planning process would be the best method for achieving both fuel diversity and system reliability. A blend of firm requirements contracts and long-term hedges could help stabilize rates. These long-term solutions will also help provide incentives to build new generation, but that alone will not suffice absent an integrated resource plan.

Office of Consumer Counsel:⁶ OCC believes that a financial hedge such as a Contract for Differences is functionally equivalent to a contract for physical delivery, so long as it meets certain specifications. (For example, the products and terms of trade must be the same, and the products must be traded in a liquid market.) Therefore, the two types of contracts – CfD and delivery contracts – can be used to meet rate stabilization, generation adequacy, and other goals. Because there is no need to dispose of energy with CfDs, they might be easier to integrate with full requirements procurements for SOLR Service.

In regard to contracts, OCC believes that intermediate and long-term contracts for energy and capacity from new resources would increase supply and thereby reduce market prices, market power, and transmission congestion.

Additionally, OCC states that utility ownership of generation would mitigate horizontal market power in energy and capacity markets. Otherwise, buyers are subject to the merchant operator's potential ability to manipulate market prices by dispatching the contracted unit in order to benefit its other units. Furthermore, utility ownership of generation would better meet the DPUC's goals in terms of fuel diversification, rate stabilization, and system reliability.

Levitan & Associates:⁷ Levitan & Associates comments that long-term contracts are not a panacea for high and volatile prices, but can be integrated into an overall portfolio in order to stabilize prices. Contracts can be structured to encourage fuel diversity as well as new investment in the state. New generation in Connecticut, secured by long-term

⁴ Ibid.

⁵ Comments of the Connecticut Light and Power Company.

⁶ Comments of the Office of Consumer Counsel before the State of Connecticut Department of Public Utility Control, Docket No. 06-01-08PH01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan approval*, January 30, 2007.

⁷ Comments of Levitan & Associates before the State of Connecticut Department of Public Utility Control, Docket No. 06-01-08PH01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan approval*, January 30, 2007.

contracts, should help moderate price volatility and reduce Connecticut consumers' exposure to congestion charges.

In regard to New England's forward capacity market (FCM), Levitan & Associates notes that FCM does not promote fuel diversity. FCM awards of up to only five years cannot provide the sort of assured revenue streams that are needed to build capacity other than natural gas units. Baseload and intermediate plants are generally more capital intensive than natural gas plants and will not be built without supplementary payments. Long-term contracts could provide a steady revenue stream to baseload and intermediate plants and could also promote fuel diversity, especially if requests for proposals (RFPs) for capacity and energy give heavier weight to non-gas technologies.

Levitan & Associates also comments on the importance of credit and assurance of revenue recovery in encouraging the development of new generation:

The merchant business model has proven inadequate in terms of providing investors and lenders with a reasonable return – market-based revenue has been insufficient or too volatile to cover all fixed and variable costs, including capital recovery. While the FCM should ameliorate this problem on a going forward basis, investment in new generation still depends on obtaining some reasonable assurance that income will be sufficient to cover costs. A creditworthy entity, backed by regulated cost recovery, who is willing to provide a stream of fixed payments for capacity over a long term can provide financial assurance needed to attract capital on competitive cost terms. Paramount is the confidence of debt lenders and equity investors that the Department will not revisit the prudence of the contract from time to time, thereby potentially giving the Companies a potential way to rescind a long term purchase obligation if, for whatever reason, the contract is detrimental to ratepayers. New generation and, in some cases, existing generation that desires to refinance, would be likely to respond to an opportunity to sell capacity, energy, and certain ancillary services on a long term basis.⁸

Retail Energy Supply Association:⁹ RESA argues against the use of long-term contracts for standard service. The association identifies several drawbacks, including:

- The contracts could wind up exceeding market rates, causing customers to pay higher prices than they would under market conditions.
- If the long-term contracts secure service at below-market rates, customers will be exposed to a rate shock upon the expiration of the contract.
- Long-term contracts undermine retail competition.
- Long-term contracts undermine energy efficiency programs by sending customers inaccurate price signals that prevent them from cutting back on their energy usage.

In addition, long-term contracts with wholesale suppliers will include risk premiums, as suppliers will need to cover the risk of fuel price rises, customer migration, and

⁸ Ibid.

⁹ Comments of Retail Energy Supply Association before the State of Connecticut Department of Public Utility Control, Docket No. 06-01-08PH01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan approval*, January 30, 2007.

regulatory risks. Evidence shows that these risk premiums increase as the length of the contract increases. RESA notes that it may be appropriate to use long-term contracts to support the construction of new plants.

Governor Rell's Energy Plan:¹⁰ Governor Jodi Rell has called for an aggressive campaign to teach residential and commercial consumers about energy efficiency programs and renewable energy. The proposal includes financial incentives to bolster these programs in the state and the expansion of net metering programs.

Another major aspect of the governor's energy plan is the establishment of a state-level Department of Energy. This new agency would take over the planning of energy needs, while DPUC's focus would be on utility regulation.

Recent activity: The governor signed a broad electricity bill in June 2007.¹¹ The new law allows electric utilities to build peaking power plants and recover the plants' cost of service, including a reasonable rate of return. Utilities must submit plans in January 2008, and the DPUC then has 120 days to approve the plans.

In addition, the new law requires utilities to implement integrated resource management plans under DPUC oversight. Utilities are allowed to respond to power supply RFPs issued in connection with these plans. If the DPUC does not receive sufficient acceptable proposals to cover the needs identified in the integrated resource plans, it has the authority to order utilities to submit proposals to build and operate plants.

Utilities can also purchase existing plants located in Connecticut if the DPUC finds that the transaction is in the public interest. In addition, the DPUC must study the feasibility of various options for standard offer service and report its findings and recommendations to the legislature by February 1, 2008.

Other sections of the new law address energy conservation and energy efficiency programs. Utilities are also required to develop plans for installing time-of-use meters and implementing voluntary critical peak or real time pricing programs for all customer classes.

¹⁰ *CT's Energy Vision: For a Cleaner, Greener State*, September 2006, accessed at <http://www.ct.gov/governorrell/lib/governorrell/energyplan.pdf>, and *Governor M. Jodi Rell's State Budget Address*, February 7, 2007, accessed at

<http://www.ct.gov/governorrell/cwp/view.asp?A=2791&Q=332098&pp=12&n=1>.

¹¹ "Law allows utilities to build peakers in Connecticut, recovery based on cost," *Electric Utility Week*, June 11, 2007. Information on the legislation, HB 7432, can be found on the state's website at http://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=HB07432&which_year=2007.

Power Supply Procurement: Delaware

Background: Under the terms of Delaware's retail choice law, rates were frozen during a transition period, and residential customers received a four-year, 7.5 percent rate reduction ending September 30, 2003. The rate reduction was extended to May 2006 in light of Connectiv's (Delmarva Power & Light's parent company) merger with Potomac Electric Power Company.

Upon the expiration of the rate freeze, Delmarva obtained power through a competitive bid process, resulting in an estimated 59 percent increase in residential rates. In response, the governor signed a law in April 2006 that provided for a phase-in of the rate increase. The new law also allows utilities to own and operate generation, and requires integrated resource planning.

At the same time, the legislature passed a joint resolution requiring the state to hire an independent consultant to study re-regulation of electric power in Delaware. The report was issued in May 2007, and its recommendations are summarized below.

Recommendations of the Delaware Report¹²

1) Periodically develop electricity priorities in a democratic process. The debate on electricity priorities can take place in numerous arenas, including the legislature and the Public Service Commission (PSC). Whatever the arena, public input is crucial to acceptance and understanding of the outcome.

The report discusses the New Jersey system where a multi-agency, multi-stakeholder process is used to develop the governor's overall goals. The public has the opportunity to comment on the plan. Ultimately, the governor decides among the proposals, and the end product is the New Jersey Energy Master Plan. Delaware could establish a similar program, and any entity that has an obligation to serve or that is involved in implementing policy in the state would be expected to follow the final plan.

The report also discusses implementing an objective process to forecast electricity demand and identify available resources. Delaware has had success with a charrette model where a group of experts meet and are expected to forge a consensus on some part of the planning process. A bipartisan council could be convened periodically to develop forecasts and estimate available resources.

2) Adopt a portfolio approach to meeting electricity resource needs. Uncertainty is a major aspect of every stage of the planning process, and uncertainty breeds risk. One way to mitigate risk is to spread it out, and a portfolio of different resources, fuels, and procurement periods accomplishes this.

¹² Nancy Brockway, *Delaware's Electricity Future: A Report Pursuant to SS1 of SJR3 of the 143rd General Assembly*, Presented to the Office of Management and Budget and the Controller General, May 2007.

Some entity or individual must be charged with managing this portfolio. A utility could play the part of portfolio manager. For example, the Delaware Electric Cooperative has a portfolio manager in its supplier, Old Dominion Electric Cooperative, and seems satisfied with this arrangement.

The utility is not always the best option. A utility portfolio manager could have a bias towards building its own plants, since the utility will receive a guaranteed return on the plant investment. In addition, the report is critical of Virginia's April 2007 legislation, which resulted in Dominion Virginia Power taking on the portfolio management role; in return, the utility received guaranteed and higher profits.

An alternative approach is for the state to take on the role of portfolio manager. The PSC could hire a professional manager from one of the firms with experience in this area, or a state agency could use in-house staff, or the recommended Delaware Energy Authority (DEA) (see recommendation #3 below) could do the job.

Whoever manages the portfolio should be given a clear mandate as to what resources should be included in the portfolio. The manager will have to decide what fraction of the portfolio will be firm commitments. The amount of baseload power procured under long-term contracts could start low and then increase over time.

The manager will also have to procure load-following supply. Rather than relying on the market for such supply procurement, laddered, short-term contracts are appropriate for this supply. For example, a system could be devised where 1/3 of the marginal load is procured every three years.

Longer-term contracts (for example 10-20 years, or life-of-unit) can increase the risk to the utility's customers by obligating them to pay for investments that could prove to be uneconomical. There are ways to mitigate some of this risk or to share it with the supplier. For example, if retail shopping increases, customers that stay on default service will have to pay the costs stranded by departing customers. In this case, an exit fee could be imposed on customers who leave default service.

The report argues that the economic benefits of using some long-term commitments outweigh the costs, especially as part of a portfolio that spreads the risk.

3) Create a state power authority to increase the options for cost-based power. Sole reliance on the market could produce artificially high prices. A cost-based option for the portfolio is also needed. One option – have Delmarva build and buy power for its customers – is unlikely mainly because Delmarva does not seem interested in resuming this role.

Another option is the creation of a state power authority. A “Delaware Energy Authority” could build generation and sell power at cost-based rates to the portfolio manager. DEA would have the authority to issue bonds in order to secure financing. DEA could directly

serve all SOS customers, or it could be a bidder offering supply to another portfolio manager.

4) Limit retail choice. The PSC has the power to limit retail choice if it determines that it is in the public interest to do so.

The report suggests that SOS customers pay a price for allowing “theoretical competition” because market prices for SOS include migration risk premiums. The report also states that the benefits of retail choice are low since so few customers select alternative supply, and only one vendor serves residential customers. One option would be to limit retail choice to large customers only and to limit the ability of customers to migrate back and forth between services.

5) Set up and implement the processes for the state’s electricity future within the coming year. State agencies, stakeholders, and the general public need to come together to forge a plan. The state must also decide who will be in charge of pulling together the resources to serve customers.

Power Supply Procurement: Maine

Background: Legislation enacted in June 2006 authorized the Maine Public Utilities Commission (PUC) to direct utilities to enter into long-term contracts for capacity and energy under certain conditions. The PUC subsequently opened a notice of inquiry into the use of long-term contracts to procure power supply. Parties filed comments in July 2006, and the PUC issued a proposed rule in October 2006¹³ and an order provisionally adopting the rule in January 2007.¹⁴

The PUC, as well as the Maine Energy Council, have also investigated Maine's continued participation in ISO New England (ISO-NE), the Regional Transmission Organization (RTO) serving Maine.

Maine PUC's Proceedings on Long-term Contracts

The PUC believes that the primary purposes of the new law's contracting provisions are to limit the cost effects of the ISO-New England capacity market and to ensure enough capacity to maintain reliability. The PUC hopes to use its long-term contracting authority as a means to garner discounts. The commission believes that a generation owner's ability to contract with a creditworthy counterparty such as a utility should motivate these entities to offer discounts off of prevailing market prices.

The PUC does not plan to use its new authority to engage in long-term integrated resource planning. Such planning would be useful in a regulated environment where utilities served defined territories on a monopoly basis, but is not practical in the current deregulated environment. Forecasting load would prove difficult and controversial. Furthermore, the commission lacks the authority to order utilities to build plants in specified locations and also has limited ability to influence developers. The PUC will continue its market approach to procuring standard offer supply and leave the burden of portfolio management to the suppliers.

The new rule, provisionally adopted in January, states that the commission may authorize long-term contracts for capacity resources as long as the contract is the least-cost way to address local grid reliability; the contract is necessary for the facility to be constructed; or the price for the capacity resource is significantly below the expected market value over the contract term. The PUC may also authorize long-term contracts for energy associated with a capacity resource if the contract is necessary to fulfill the renewable capacity resource policy or if the energy is used to supply Standard Offer Service and its price is below expected market value. Long-term contracts are not to exceed ten years unless the commission finds that a contract in excess of ten years is in the consumer interest.

¹³ State of Maine Public Utilities Commission, "Notice of Rulemaking," Docket No. 2006-557, *Long-Term Contracting and Resource Adequacy*, October 3, 2006.

¹⁴ State of Maine Public Utilities Commission, "Order Provisionally Adopting Rule and Statement of Factual and Policy Basis," Docket No. 2006-557, *Long-Term Contracting and Resource Adequacy*, January 2, 2007.

In order to procure capacity resources, the commission will conduct competitive bid solicitations, through an RFP process, at least every three years unless the commission determines that benefits realized from the solicitation process will not exceed costs.

Comments from Parties on Long-Term Contracting

AARP Maine:¹⁵ AARP calls on the state to encourage the use of long-term contracts in order to enhance system reliability and suggests that renewable and energy efficiency programs be integrated into the Standard Offer Service portfolio. AARP also recommends a change to Maine statutes that would place distribution utilities in charge of conducting and implementing all planning and acquisition activities related to SOS and resource capacity planning, subject to the commission's approval and renewal. AARP also advocates that the PUC develop long-term load forecasts in order to improve long-term planning.

WPS Energy Services:¹⁶ WPS does not think that regulated utilities should be forced to enter into long-term contracts. If the PUC does direct utilities to enter into such contracts, all segments of the generation sector should have an equal opportunity to be involved in the competitive bid process.

WPS also encourages the commission to prioritize its ultimate goals. If price stability is the primary goal, then the commission should encourage long-term contracts. But if the commission prefers to have SOS trend the market, then the commission should encourage short-term contracts. Long-term contracts should be for both capacity and energy.

In terms of load forecast, the PUC should be involved, but other industry participants should take the lead.

Bangor Hydro-Electric Company:¹⁷ BHE fears that long-term contracts would transfer risks to transmission and distribution companies. Long-term contracts could be treated by financial companies as imputed debt, resulting in a higher cost of capital that will ultimately be passed along to customers. If the Commission provides reasonable assurance of cost recovery, such concerns could be mitigated.

The utility asserts that the state needs to re-examine the prohibition on utility ownership of generation. If transmission and distribution utilities are to be required to obtain energy supply for customers, then these utilities should be permitted to "put iron in the ground" and develop their own facilities.

¹⁵ Comments by AARP Maine before the Maine Public Utilities Commission, Docket No. 2006-314, *Inquiry into Long-Term Contracting and Resource Adequacy Planning*, July 10, 2006.

¹⁶ Comments of WPS Energy Services, Inc before the Maine Public Utilities Commission, Docket No. 2006-314, *Inquiry into Long-Term Contracting and Resource Adequacy Planning*, July 14, 2006.

¹⁷ Comments of Bangor Hydro-Electric Company before the Maine Public Utilities Commission, Docket No. 2006-314, *Inquiry into Long-Term Contracting and Resource Adequacy Planning*, July 10, 2006.

Central Maine Power Company:¹⁸ CMP argues that there is a fundamental design flaw in Maine’s retail generation service, and the PUC cannot mandate that transmission and distribution utilities contract for power supply absent a reassessment of the structure of Maine’s electric market. The PUC no longer has control over generating units, so customers are subject to the volatile prices produced by the ISO-NE market. One step that the state could take is to work collaboratively to encourage a portfolio of generation capacity that reflects a variety of fuel types and a mix of baseload, intermediate and peaking facilities.

T&D utilities should be allowed to own generation. Regulated utilities are better able than unregulated generators to secure long-term financing on favorable terms, and, as experience in New Hampshire and Vermont shows, utilities that were able to maintain ownership of generating assets will see less exposure to ISO-NE’s capacity charges.

Maine Energy Council Report¹⁹

The Council recommends the development of a Comprehensive State Electricity Plan that would examine the energy needs of the state and formulate scenarios and strategies for both the short-term and long-term. The report notes that the region has become over-reliant on natural gas, resulting in greater risk of supply shortages and volatile prices.

The Council is divided on both the issue of utility ownership of generation and utilities’ ability to enter into long-term contracts. The Council does recommend that a strategy be forged to minimize peak electricity use, and it also recommends accelerating energy efficiency efforts. The Council notes that renewable generation resources can be used to reduce and stabilize costs and enhance system reliability. The Council also recommends that the PUC continue to explore the possibility of leaving ISO-NE.

PUC Report on Leaving ISO-NE²⁰

Largely in response to the approval of ISO-NE’s new forward capacity market, the governor directed the PUC to investigate the costs and benefits of remaining in ISO-NE. The PUC’s interim report, published in January 2007, found that:

- Inequalities exist in ISO-NE’s transmission cost allocation system and the pricing of generation services.
- The legal, economic and technical barriers to the state utilities (CMP and BHE) exiting ISO-NE are not insurmountable.
- Reasonable alternatives to ISO-NE exist. Among the alternatives are formation of independent transmission companies, and the development of a Maine/Canadian Maritimes market.

¹⁸ Comments of the Central Maine Power Company before the Maine Public Utilities Commission, Docket No. 2006-314, *Inquiry into Long-Term Contracting and Resource Adequacy Planning*, July 10, 2006.

¹⁹ “Maine Energy Council Report,” April 9, 2007.

²⁰ Maine Public Utilities Commission, “Interim Report,” *Pursuant to “A Resolve to Direct the Public Utilities Commission to Examine Continued Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization*, January 16, 2007.

The PUC concludes that the current ISO-NE transmission cost allocation and pricing mechanisms are inequitable. For example, Maine ratepayers are achieving minimal benefits from the new transmission projects in southern New England. Proposed projects in Maine that would serve the rest of the region will be of greater benefit to the region than to Maine, and in fact, could raise prices in Maine. The PUC also finds that Maine has generated more electricity than it has consumed over the past decade, and that Maine's capacity payments would be lower under an alternative structure than under ISO-NE's new forward capacity market.

Compatibility between Maine and the Canadian Maritime Provinces suggests that each side would benefit from a common market. Load growth in both areas is predicted to rise moderately. Moreover, the installed capacity in the area should be sufficient to meet this load growth. The market would have a diverse fuel mix that would provide a hedge against volatile fuel prices.

An Independent Transmission Company (ITC) would be a non-profit company that owns only transmission. It would therefore focus on identifying transmission needs and developing new projects. It would also oversee operation of the transmission system.

The PUC's final report is due by January 1, 2008.

Power Supply Procurement: Maryland

Background: Maryland's 1999 retail choice act called for traditional electric utility companies to provide standard offer service (SOS) to those customers who did not choose alternative suppliers. The Public Service Commission (PSC) mandated that utilities procure power supply on a competitive bid basis with contracts varied between one, two, and three years. As a part of the procurement process, bids were solicited in late 2005 and early 2006. Prices were much higher than in previous solicitations, and as a result, the legislature directed the PSC to conduct a study on the status of electricity restructuring in Maryland and to evaluate various options for procuring power supply for customers.

PSC Report²¹

The PSC's report, issued in December 2006, found that the price increases were due in large part to hurricanes Katrina and Rita and their impact on natural gas supplies. High demand in the summer of 2005 and constrained transmission also led to higher prices. A typical customer's bill increased anywhere from 35 to 72 percent as a result of the procurement.

The PSC report described SB 1, which was enacted following the price increases and amended the original restructuring legislation. The new law imposes continuing obligations on investor-owned utilities to provide standard offer service and provides new standards and options for SOS. The PSC opened Case No. 9063 to address the new requirements in regard to the long-term procurement process, including:

- Procurement of SOS in competitive bids or through bilateral contracts;
- Blending of different short, medium and long term contracts and a bid process that includes different structures and mechanisms for base and peak load;
- Procurement of energy-efficiency and conservation measures that would offset increased demand;
- Staggered wholesale auction dates;
- The PSC's ability to change the bid date based on market conditions;
- The utility's ability to refuse or accept some or all of the competitive bids;
- Public disclosure of the names of all bidders, as well as names and bid allocations of all successful bidders.

Industry members offered proposals for SOS service and also commented on utility ownership of generation. The following summary describes their recommendations.²²

Recommendations

Five SOS proposals were offered. They were:

²¹Public Service Commission of Maryland, "Report to the Governor and Maryland General Assembly on the Status of Electric Restructuring and the Structure, Procurement, and Terms of Standard Offer Service," December 31, 2006, pp. 1-7.

²² Testimony summaries can be found in the PSC report, pp. 10-37.

1. Quarterly 25 Percent Bidding – One-year Contracts. Conduct bids for 25 percent of the SOS load, four times a year. The contracts would be for one-year terms.

2. Rolling Three Year Contracts. Use the existing full requirements procurement method (FRPM) to purchase 33 percent of SOS load each year. Contracts would be for three-year terms.

3. One year 100 Percent Contracting. Conduct the FRPM using annual contracts, with 100 percent of SOS load up for bid every year.

4. Monthly Bidding. Procure 100 percent of the load each month under one-month contracts.

5. Managed SOS Portfolio. Use a managed portfolio containing generation contracts and assets owned by distribution companies in each service territory. Utilities should also evaluate various contract terms and types over the long term.

Participant Positions

Maryland Energy Administration (MEA): The procurement process has generally worked well, and it should be modified to provide for laddered three-year contracts as an interim measure. Energy prices will remain volatile due to fuel costs and changing environmental controls. MEA discussed utility ownership of generation as a supply option. Utility ownership of generation would entail utilities making very large investments, which in turn would require cost recovery assurances. That would mean either ending retail choice, or the implementation of some form of stranded cost recovery. Prices will not return to pre-deregulated levels because new generation would be based on current costs. High fuel and environmental costs could also drive up prices. Moreover, MEA estimates that it would take at least six years for benefits to accrue to customers. MEA believes long-term supply contracts would lead to similar results as utility ownership of generation.

MEA also recommended that the PSC study opt-out aggregation; restrictions on retail choice; establishment of a state power authority; and giving utilities greater flexibility to enter into bilateral contracts.

Allegheny Power: AP supports the continuance of the current full requirements procurement process, with the goal of achieving a blended portfolio of mixed-length contracts.

Baltimore Gas and Electric: BG&E also supports the current procurement model and opposes long-term power purchase agreements because they would undermine competitive markets. BG&E would modify the current process by using “laddered” three-year contracts, with a third of the SOS load purchased annually. BGE witnesses also suggest using a descending clock auction as used in New Jersey.

Potomac Electric Power Company /Delmarva Power and Light: The utilities also support competitive bidding for staggered three-year contracts. They do not support the use of negotiated contracts or utility construction of generation.

Office of the People’s Counsel (OPC): OPC states that various supply options, including long-term contracts in excess of ten years, should be considered. SOS providers should obtain the best price for customers, and these prices should reflect the “actual and documented” prices for providing service. OPC urges the Commission to force the utilities to begin a 10-15 year procurement planning process that would consider all procurement options. OPC believes that long-term contracts could provide greater price stability and that more than one type and duration of supply product should be considered.

Retail Energy Suppliers Association: RESA states that SOS should be re-priced monthly in order to make it more market responsive. The association also argues that utility ownership of generation would reestablish the risks that customers and utilities faced prior to deregulation.

Washington Gas Energy Services (WGES): WGES states that the current power procurement process should be maintained, but contracts should be limited to one year terms. Price volatility should be addressed by rate stabilization plans and budget billing.

Constellation Energy Commodities Group (CECG) and Conectiv Energy Supply, Inc. (CESI): CECG believes that competitive procurement procedures are better than utility ownership of generation or managed portfolio approaches. CECG also opposes opt-out aggregation –where a city or town becomes the default supplier for residents and customers must affirmatively opt out of the municipal group.

CESI argues that monthly SOS auctions would lead to less wholesale supplier participation. In contrast, bids for three-year contracts might attract more wholesale supplier participation because currently such opportunities are rare.

Maryland PSC Technical Staff: The staff identifies six criteria for the Commission to consider when evaluating procurement proposals:

- 1) reliability of service should be maintained;
- 2) the procurement process should be transparent;
- 3) the procurement method should result in prices that mirror or closely approximate electricity market conditions;
- 4) the SOS procurement method should not be administratively burdensome or costly;
- 5) price shock should be avoided if at all possible;
- and 6) the power procurement method selected should be competitively neutral.²³

The staff recommends the use of more time-of-use pricing in order to meet the mandate for energy conservation and efficiency. Power procured for SOS should use a quarterly layered bid process for one-year contracts, with each quarterly bid representing 25 percent of the total SOS load. Staff also calls for stakeholders to develop an “electricity road map” in order to transition from SOS to fully competitive markets.

In its summary of the various issues, the PSC report noted that Commission Staff suggested a plan that would allow utility ownership of generation, but still keep the

²³ PSC report, p. 26.

benefits of a competitive market. All customers would pay a non-bypassable charge to fund utility generation, and the utility would sell all of the power into the market. The sales would constitute a price hedge and would not be a part of standard offer service.

The PSC summary of issues also noted that there was no support for the proposal to allow private, negotiated contracts between a utility and a supplier.

Further Investigations

BG&E Rate Order: In its May 2007 order approving BGE's rate increase and rate mitigation plan,²⁴ the PSC concluded that while the rate increase met legal standards, the current process for determining SOS rates is not optimal. As a result, the Commission will consider implementation of a managed portfolio approach and will investigate whether "best price" – rather than market price – requirements for SOS procurements would undercut retail competition. The Commission will also review how the wholesale market operates, with the purpose of identifying factors that do not benefit Maryland consumers. As part of the review, the PSC will analyze how PJM's reliability pricing model (RPM) may affect retail customers. The PSC intends to play an active role in addressing wholesale market issues.

The PSC's order also discussed substantial concerns about the adequacy of resources in the state and region. Consequently, the PSC will initiate a process to investigate long-term demand estimates and capacity resource projections. Finally, in regard to the actual bidding process for SOS power, the PSC will review the criteria used in determining when bids are inappropriately high. The PSC will also look at whether BG&E's obligations as an electric utility and the financial interests of its affiliate, Constellation Energy Generation Group, are in conflict.

Independent Report on Maryland's Electricity Industry: Legislation enacted in May 2007 directs the PSC to conduct an analysis of the state's electricity industry and report to the Legislature by the 2008 session. In June, the PSC issued an RFP to select an independent consultant to conduct the study. Issues to be covered include: the costs and benefits of re-regulating Maryland's electricity market; options for developing new generating resources; the cost-effectiveness of various demand-side options; the profitability of Constellation Energy's generating assets; and the effect of wholesale electricity markets on retail rates.²⁵

²⁴ Maryland Public Service Commission, "Executive Summary," *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan Pursuant to Section 7-548 of the Public Utility Companies Article and the Commission's Inquiry into Factors Impacting Wholesale Electricity Prices*, May 23, 2007.

²⁵ Corina Rivera, "Maryland issues RFP for analysis of state's electric industry," *Electric Utility Report*, SNL Energy, June 25, 2007.

Power Supply Procurement: Massachusetts

Background: In October 2006, the state’s Division of Energy Resources (DOER) petitioned the Department of Telecommunications and Energy (DTE) to investigate the pricing structure of basic service and whether customers would be better off with a dynamic pricing structure that would more accurately represent wholesale market prices.²⁶ DTE then issued a request for comments on the appropriate scope of an investigation into dynamic pricing.

In November 2006, several entities, representing utilities, suppliers and customers, submitted comments in the proceeding. In general, the comments support a further investigation into dynamic pricing. However, NSTAR’s comments, summarized below, recommend a much broader evaluation of basic service, including an analysis of how competition in both wholesale and retail markets has evolved.

DOER Proposal

DOER argues for dynamic pricing in their petition:

Dynamic pricing of basic service would encourage consumers to utilize electricity more efficiently, in better alignment with its true cost and value. These pricing regimes would enable them to save money by shifting consumption to off-peak periods, be more productive by using more electricity during those off-peak periods and reduce the cost to society of maintaining large amounts of resources in reserve to be used only rarely at peak consumption periods. Dynamic pricing would reduce or delay the need for new generation resources, especially peaking resources, foster more efficient use of existing generation resources, increase the proportion of demand resources competing economically in the marketplace, and foster use of new technologies that would allow consumers to automate adjustments to their consumption so that it occurs when its actual value more closely align with their willingness to pay for it.²⁷

The petition highlights four different pricing plans:

Real-Time Pricing (RTP): Prices are set every hour to reflect hourly ISO day-ahead market Location Marginal Pricing (LMP) or real-time market LMP.

Time-of-Use (TOU): Prices are set in advance for different times of the day.

Critical Peak Pricing (CTP): The TOU peak price is replaced during “critical circumstances” by a critical peak price. Price changes are made on short notice (usually one day or less).

Variable Peak Pricing (VPP): Off-peak prices are set in advance while peak prices are set each day to the average of the corresponding ISO day-ahead market hourly LMPs.

²⁶ “Petition of the Massachusetts Division of Energy Resources for an Investigation into Dynamic Pricing for Basic Service,” submitted to the Commonwealth of Massachusetts Department of Telecommunications and Energy, October 31, 2006. DTE has since been split up into two agencies, and the Department of Public Utilities (DPU) now handles electric, gas and other issues.

²⁷ Petition, p. 6.

Comments of NSTAR Electric Company:²⁸ NSTAR recommends that the Department open a proceeding to assess both wholesale and retail power markets, including how competition in wholesale markets affects the price of basic service. Other issues to consider include: how electric companies plan for basic service; how modifications to basic service can be made so as to maximize benefits to customers; and the role of basic service in securing resource adequacy.

In supporting its proposal, NSTAR cited numerous concerns with wholesale and retail markets:

- Competition has emerged in the wholesale market for generation generally throughout Massachusetts, but many generators in constrained areas such as Boston operate under cost-of-service reliability must-run agreements (RMR). Twenty-two percent of generating capacity in New England is under or applying for such agreements.
- Customers on standard service are subject to volatile market-based prices because so much of the market is driven by natural gas and oil. There is a need for greater fuel diversity. There is also concern about the long-term adequacy of resources due to long lead-times in bringing new facilities into the market.
- Separation of generation and transmission creates the potential for costly redundancies because facilities are planned, constructed and owned by different entities that are each attempting to address congestion and other supply situations that put pressure on prices.
- In regard to retail markets, 50 percent of NSTAR's residential customers have an average energy bill totaling \$46, so even a five percent savings results in less than \$2.50 per month in customer benefit. These savings are too small to motivate customers to participate in retail choice programs. As a result, basic service, which was planned as the fallback rate, has become the standard for most small customers.
- There is little flexibility to structure basic service in such a way as to reduce costs. Utilities must procure 50 percent of residential and small customer load in a one-year contract, twice a year. After hurricanes Katrina and Rita, utilities were required to purchase 50 percent of their power needs at a time of high prices, and retail rates went up by 35 percent. The total cost impact from this inflexible procurement system was approximately \$250 million over the one-year period of the contract.
- Because basic service was set up to encourage customers to switch to competitive service, suppliers must plan for customer migration and include a premium for load-following service (supply that increases or decreases depending on load size). In addition, suppliers often employ a middle man, such as a marketer, to manage the risk of providing load-following service, further adding to the cost.
- NSTAR must follow the proscribed procurement process of obtaining supply in a large block for a short period. Greater flexibility to procure supply on a targeted basis to meet the needs of individual subsets of the portfolio would benefit customers.

²⁸ Comments of NSTAR Electric Company, "Petition of the Massachusetts Division of Energy Resources for an Investigation Into Dynamic Pricing for Basic/Default Service," Docket D.T.E. 06-101, before the Commonwealth of Massachusetts Department of Telecommunications and Energy, November 28, 2006.

Power Supply Procurement: Michigan

Background: By January 2002, all customers of Michigan's investor-owned utilities, Detroit Edison and Consumers Energy, could choose their electricity suppliers. However, Michigan differed from many other retail states in that the two utilities were not required to divest their generation assets. As a consequence, when the rate freeze expired at the end of 2005, residential rates increased by only moderate amounts, especially as compared to the very large increases experienced in other retail choice states at the time.

In April 2006, Governor Jennifer Granholm signed Executive Directive No. 2006-2 directing the Michigan Public Service Commission (PSC) to prepare a 21st Century Energy Plan. A primary purpose was to ensure adequate generating resources for the future. The Commission solicited information from all segments of the electric industry and presented its report to the governor in January 2007.

21st Century Plan: Recommendations²⁹

Utilities could build their own generation under traditional regulation or could choose an alternative option. Under the second option, the Commission would grant a Certificate of Need to utilities once they submitted an integrated resource plan.

All load serving utilities in the state would be required to meet a renewable energy portfolio standard of 10 percent by the end of 2015. Utilities would be able to meet the standard either through ownership of renewable generation, contracting with in-state generators, renewable energy credits, or making an alternate compliance payment.

The state would create the Michigan Energy Efficiency Program and fund it through a surcharge on all customers' bills. The program would be administered by a third party under the supervision of the PSC.

21st Century Plan: Forecasts

Michigan's total electric generation needs are predicted to increase at an annual rate of 1.3 percent from 2006 to 2025.³⁰ To meet long-term capacity needs, coal will continue to be the fuel of choice. Natural gas was rejected as a baseload resource because of its price volatility, and nuclear was excluded for the first half of the forecast period because of the extremely long lead time in getting a new plant built. Since more state and federal environmental regulations are likely to emerge – including some form of carbon dioxide tax – generation costs are likely to increase, raising the costs at coal-fired electricity plants by 1.5 to 2 cents per kilowatt-hour. Integrated gasification combined cycle (IGCC) could be a useful technology to reduce carbon dioxide emissions and would be a potential alternative to conventional coal-fired plants. But the technology is not immediately available, thus renewable energy sources and energy efficiency are currently the best protection against the risks associated with building new coal generation.

²⁹ Full details of the PSC's proposals can be found at *Michigan's 21st Century Electric Energy Plan*, submitted by J. Peter Lark, Chairman, Michigan Public Service Commission, January 2007, pp. 3-7.

³⁰ *Ibid.*, pp. 9-12, for forecast information.

21st Century Plan: Detailed Recommendations

Michigan is a hybrid power market in which utilities still own generating assets and sell power at regulated rates and alternative energy suppliers sell primarily to the commercial and industrial sectors at market rates. New baseload plants are needed as protection against volatile market prices. However, utilities are reluctant to build plants given the ability of their customers to switch to alternate suppliers, and independent power producers (IPPs) are reluctant to build absent long-term purchase power agreements, which utilities are generally unwilling to sign.

The Plan looks at three policy alternatives. One option is to re-regulate the market; another is to fully deregulate it. The Plan does not recommend either course. The former would remove customer choice from those who might find economic benefit from an alternative supplier, and the latter could lead to a significant wealth transfer from ratepayers to the owners of deregulated generation assets.

The PSC recommends a third option, which would require a legislative change. Utilities could choose to build generation by first acquiring a Certificate of Need from the PSC. Once the utility has the certificate, the reasonableness and prudence of building the plant would not be subject to challenge. (However, the utility would still have to prove that the plant's costs were prudent before it was granted cost recovery.) The utility would first present an integrated resource plan (IRP) detailing how it would use energy efficiency, renewable energy, transmission, existing regional resources and new generation to meet demand.³¹ The Commission would have 270 days to issue or deny a certificate for new generation justified in the IRP.

New baseload capacity added to the regulated system lowers market prices, so all customers benefit. Thus the Plan recommends that all customers – including migrating customers – pay for new capacity. While the Commission deliberates on the Certificate of Need proposal, the utility must notify its customers of the pending plant development. Once the Certificate is granted, the customer market to be served by the new generation should be grouped into three classes:

- Customers taking regulated service will be charged traditional rates based on cost recovery;
- Customers who leave the regulated service must carry a non-bypassable charge to cover their share of the new construction; and
- Customers who are off regulated service, and never return, will face no charges.

Customers who wish to return to regulated service must give 60 days notice that they wish to return and must pay rates under a market-based rate tariff for the first two years of their return to service.

In order to diversify the state's energy portfolio, lower prices, and reduce emissions, the Plan also calls for legislation to enact a mandatory renewable portfolio standard (RPS)

³¹ Ibid, pp. 16-41, for plan recommendation details.

that would require all load serving entities (LSE), including municipal and cooperative utilities, to increase the amount of renewable energy in their portfolios to ten percent by 2015. The Plan recommends that the PSC be allowed to raise the standard to 20 percent by 2025.

The Plan estimates that after ten years, an effective energy efficiency program could reduce peak demand by 660 megawatts (MW) and annual energy use by 4,952 gigawatt hours (GWh). Thus the Plan proposes the creation of a program to promote efficiency, funded by a direct uniform charge on customers' bills. The proposed Michigan Energy Efficiency Program would be administered by an independent third party, and all of the state's utilities would be required to participate in the fund.

Utilities could also take active and passive steps to encourage energy efficiency. An example of an active step is Detroit Edison's air conditioning cycling program, where a signal is sent to the customer's air conditioner or hot water heater during peak periods and shuts it off. Passive programs are those in which the utility relies on customer behavior. For example, utilities could implement time-of-use rates where the customer is provided different rates for different times of the day, and then chooses when and if to limit energy use. The Plan also recommends updating building codes in order to make them more energy efficient.

Power Supply Procurement: New York

Background: New York State began the process of restructuring the electric utility industry in 1996.³² The Public Service Commission (PSC) oversaw the creation of competitive retail markets and the divestiture of investor-owned utilities' generating assets. An independent entity – the New York Independent System Operator (NYISO) – was created to administer the wholesale power market. Currently, the NYISO operates three forward auctions of installed capacity; the longest goes out six months.

New York City Bar Association Report

The New York City Bar Association presented a report detailing problems with the state's deregulated electric market and offering recommendations. The February 2007 report notes that electric prices in the state remain substantially higher than the national average. The limited amount of new capacity that has been added over the past few years is putting further upward pressure on prices. New capacity is also needed to ensure a workably competitive market, maintain system reliability and limit price volatility.

The state has generally permitted the marketplace to sort out where new capacity should be built. While independent power producers have received permits to construct new plants, some of these producers have decided not to go ahead with construction. The power producers are reluctant to build in the absence of long-term power supply agreements (PSAs), and there is no long-term forward capacity market in New York.

Report Recommendations:

In light of these issues, the Bar Association offers three options to encourage the construction of new generation:

- Have the New York Independent System Operator create a long-term market for capacity that would promote merchant power plant development;
- Facilitate the ability of utilities and other load serving entities to enter into long-term (10 years or more) PSAs; and
- Create a new entity, or restructure an entity such as the New York Power Authority (NYPA), that could purchase power under long-terms PSAs.

Report Details:³³

Creation of an adequate forward capacity market: Neighboring regional transmission organizations (ISO-NE and PJM) conduct auctions for capacity three years ahead of delivery. Creating a longer-term forward capacity market in New York would bring the state more in line with the wholesale market setup of its neighbors and encourage long-term PSAs. Making the forward market's planning horizon similar to New York's reliability plan would also encourage new market-based resource additions.

³² Background on New York's electric restructuring plan and its aftermath can be found in The Association of the Bar of the City of New York, Committee on Energy, *Electric Regulation in the State of New York*, February 9, 2007, pp. 1-7.

³³ *Ibid.*, pp. 12-25, for details of the proposal.

The report notes several disadvantages of such a market. Changing the rules would benefit some participants while injuring others and changes the expectations of all market participants. A long-term capacity market may carry substantial costs, which would be passed onto ratepayers. Also, the experience of neighboring states has thus far been limited and may not provide sufficient insight into how well the markets function. The three-year planning horizon of these markets is still significantly shorter than the PSAs of ten years or more that are generally needed to provide for reasonable financing options.

Encouraging utilities to enter into long-term PSAs: The New York PSC does not offer advance prudency approvals for long-term PSAs, and utilities are hesitant to enter into these contracts without certainty that they can recover the costs in their rates. One alternative would be for the PSC to produce a regulatory “roadmap” which would give confidence to utilities that the commission would likely grant cost recovery approval. The utility would have to undertake due diligence measures to establish the reasonableness of costs. In turn, the PSC would only consider the facts as they appear under market conditions at the time the PSA was negotiated and disregard later market changes. The roadmap would also have a review process to make sure that the utility explored alternatives such as demand-side resources before entering into a PSA.

An advantage of this option is that long-term contracts will result in new capacity and lead to reduced costs for capacity and energy for consumers. This alternative could also diminish the concentration of supply-side market power in New York City, leading to lowered costs. Additionally, it bolsters the credit of the entity building the capacity, lowering interest rates and prices. The report also states that the risk shifted to the utility and/or customer could be lessened by state-administered energy planning, which would, among other things, decide when a utility should enter into a long-term PSA.

The report notes several disadvantages with this option. It mentions the poor record of New York in predicting what the appropriate investments in new capacity should be – a record that has led to the building of uneconomic facilities. In addition, the PSC could be influenced by shifting economic and political pressures to limit the ability of the utilities to recover the cost of PSAs. Further, long-term PSAs will distort market price signals and potentially undermine competitive retail markets. This will limit the ability of energy suppliers to develop products to meet specific customer needs.

Creating a new entity or restructuring an old one to ensure financing of new generation capacity: The state could create a Special Purpose Entity (SPE) that would solicit capacity when the market fails to provide new generating capacity. The state could create an entirely new entity for this purpose, or NYPA could be restructured. The report details how the SPE would function:

The SPE would issue an RFP requesting bids for capacity or capacity and energy. The RFP could seek physical generation, demand side resources or transmission, depending on the need and NYISO requirements. Upon an award, the SPE would enter into a PSA of sufficient duration to enable the developer to finance the project. The SPE would offer to resell the products purchased under the PSA through an auction, under which [Energy Service Companies], marketers, utilities, etc. could buy all or part of the RFP products.

Any amounts not disposed of by this process would be sold by the SPE into the NYISO-administered markets (e.g., capacity auctions and/or the daily energy markets).³⁴

One of the advantages of this proposal is that it maintains the market function, but provides a backstop in case the market fails. This model could lead to the development of infrastructure, such as renewables and clean coal, that otherwise would not be built in a pure market setup. Also, were NYPA to be the SPE, it has already established good credit and has experience dealing with RFPs and PSAs.

The report also notes some disadvantages with this proposal. It could undermine competitive markets and discourage new market-based resources. It could be difficult to convince the public that the best deal is available from an entity that chooses the winning bids and is also assured cost recovery. In addition, it will be difficult to guarantee cost recovery for the SPE, given past experience with prudency reviews and the general reluctance of the PSC to bind future commissions. Also, the need for legislative action could delay implementation of the proposal.

Other report recommendations: The report also recommends that New York re-institute state-administered energy planning. State energy plans had been effective at forecasting energy needs, but none have been issued since 2002. While NYISO does address reliability needs, its reports are not nearly as comprehensive as the state energy plans and do not address fuel diversity, demand response and efficiency programs, and other non-reliability issues. The NYISO planning process also does not adequately address economic needs, leading to concerns as to whether the competitive market provides the right signals to encourage new capacity in areas where customer costs are the highest. As such, the report suggests that New York adopt a state-administered program such as the one in neighboring Pennsylvania or along the lines of the New England Regional State Committee.

³⁴ Ibid., p. 19.

Power Supply Procurement: Ohio

Background: Electric choice went into effect in the state of Ohio in 2001. Ohio's transition period was to end in December 2005. As the date approached, the Public Utilities Commission of Ohio (PUCO) grew concerned that too few competitive suppliers had emerged, and therefore strictly market-based rates could harm ratepayers. Rather than following the Ohio law that required utilities to offer customers the choice of a market-based standard offer or a competitive bid option, the PUCO worked with individual utilities to establish Rate Stabilization Plans (RSPs) in an attempt to keep prices from escalating.

Rate Stabilization Plans: Each individual utility was granted a unique plan.³⁵ American Electric Power (AEP) was given a three-year plan lasting from January 1, 2006 to December 31, 2008, raising generation rates for each Columbus Southern customer by three percent annually through this period, and seven percent annually for Ohio Power customers. Distribution rates were frozen until 2008. Duke Energy's plan encompasses the same time period, with generating rates changing on a quarterly basis in order to account for fuel costs and the costs of environmental compliance. The first 25 percent of Duke residential customers to shop for alternative power supply can avoid some of these charges.

Dayton Power & Light (DP&L) has an RSP that runs for five years, extending until December 2010. The RSP caps generation rate increases at 11 percent over this period, with residential customers receiving a 7.5 percent generation discount on monthly bills from 2006 to 2008. Distribution rates are frozen through 2008.

FirstEnergy's RSP also runs from 2006 to 2008. An auction was conducted to see if FirstEnergy could procure cheaper energy supply, but PUCO rejected the auction results because they would have led to higher rates than those under the RSP. PUCO also implemented a Rate Certainty Plan (RCP) for FirstEnergy, which further stabilizes prices, including fuel and distribution-related costs.

Office of the Ohio Consumers' Counsel's Report: In its February 2007 report to the Ohio General Assembly, the Office of the Ohio Consumers' Council (OCC) criticizes these RSPs and claims that they have failed to stabilize rates or foster competition.³⁶ The OCC has challenged these RSPs in Court, and some of them have been reversed in part.

Under its RSP, FirstEnergy is allowed to collect a Rate Stabilization Charge (RSC), which the OCC claims has no basis in law. The RSC allows FirstEnergy to continue recovering stranded costs from its customers even though such charges were supposed to be prohibited after the end of the market development period. Additionally, FirstEnergy's RSP makes it hard for switching customers to actually save any money, as they are faced

³⁵ Details for each RPS can be found at PUCO's Website at <http://www.puco.ohio.gov/PUCO/Consumer/Information.cfm?id=6102>.

³⁶ Office of the Ohio Consumers' Counsel, *Biennial Report on the State of Electric Restructuring*, prepared by Janin L. Migden-Ostrander, February 8, 2007.

with high non-bypassable charges – charges the customers must pay even if they switch providers. Ohio’s Supreme Court ruled that PUCO overstepped its jurisdiction in allowing a plan which does not provide customers a “reasonably available alternative.”

OCC also successfully appealed AEP’s RSP, and the Ohio Supreme Court remanded the case to PUCO for further proceedings. PUCO subsequently approved a plan allowing cost recovery for AEP’s proposed integrated gasification combined-cycle (IGCC) plant before the plant is completed. OCC says that the plan shifts risks to consumers. It also contradicts the deregulation law’s prohibition on a distribution company’s ownership of generation, because the plant is designed to provide power to an AEP distribution company. OCC is currently challenging this decision.

Duke’s (Cincinnati Gas & Electric) RSP also includes non-bypassable charges, which are divided into four segments. One of these tracks fuel charges. The charges put competitive suppliers at a disadvantage because customers will not want to pay fuel charges twice. OCC successfully appealed PUCO’s decision to Ohio’s Supreme Court, as the Court ruled that PUCO did not provide ample evidence to support its decision to grant these charges.

DP&L’s market development period ended in 2003, but because no competition existed in the utility’s territory, DP&L entered into a settlement agreement – the first RSP – to extend the market development period until 2008. DP&L subsequently requested changes to the plan, and it has now been extended to 2010. The RSP includes an Environmental Investment Rider, which is a non-bypassable charge to customers. The OCC believes that the corporate separation requirements prohibit the non-bypassable charge and has filed an appeal with the state Supreme Court.

OCC concludes its report by noting that competition has been declining in Ohio, with fewer customers taking alternative supply and virtually no shopping in the residential sector. Would-be competitive suppliers are not entering the market due to the RSPs’ low shopping credits. Aggregation has also dissipated.

Seams issues further complicate matters. The Ohio market is governed by two different RTOs. AEP and DP&L are in PJM, and FirstEnergy and Duke belong to the Midwest Independent System Operator (MISO). These RTOs have different structures and rules, and these inhibit efficiencies in the market mechanism.

Conclusions: OCC argues that an auction system as was originally attempted with FirstEnergy would provide lower prices. In order to serve non-switching customers, OCC proposes a competitive bid system in which the supplier would provide power based on slices or “tranches” of the system. The system should use a portfolio approach incorporating long-term and short-term bids, providing a diverse set of options.

Power Supply Procurement – Pennsylvania

Background: Pennsylvania’s restructuring legislation was signed December 3, 1996. It included two rate caps: total rates were capped at January 1, 1997 levels for 54 months, and the generation portion of a utility’s rate was capped at nine years or until the time the utility no longer was recovering its stranded costs, whichever was shorter. The Pennsylvania Public Utilities Commission (PUC) approved various Provider of Last Resort (POLR) plans for investor-owned utilities dealing with service for those customers that did not choose alternative supply.

Pike County Light & Power’s rate cap ended December 31, 2005, and through an October 2005 auction, the utility obtained power supply for a two-year period beginning January 2006. The resulting very large rate increases for the utility’s customers led the PUC to open a series of proceedings to address the potential for high rate increases once the transition period ends for other Pennsylvania utilities and the optimal design for default service.

Summer 2006 Comments on Mitigating Price Increases³⁷

Penn Future:³⁸ PennFuture advocates policies and programs that will encourage diverse fuel portfolios and reduce peak demand. PennFuture offers several proposals: the PUC should require utilities to file transition plans that address key conservation, energy efficiency and renewable resource issues; the PUC should launch a consumer education program to teach energy conservation; the PUC should require each utility to install metering, communications and other equipment geared to allow customers to voluntarily alter their energy usage; and the PUC should allow utilities to offer voluntary, alternative rate plans for the remainder of the transition period.

Energy Association of Pennsylvania:³⁹ The Energy Association of Pennsylvania represents electric distribution companies (EDCs). The association supports consumer education programs but believes that the \$25 million figure proposed by PennFuture is arbitrary and premature. It is first necessary to set goals for demand response. For example, the cost of implementing programs must be determined, and the industry should decide if it wants customer to cut back on usage at all times or if it wants them to cut back only at specific times. The diversity of EDCs also argues against a solitary statewide advertising approach.

The association also argues that the Low Income Usage Reduction Program (LIURP) is more effective in reducing energy usage than an advertising program would be. The Commission should focus its energies on cost-effective policies that have worked elsewhere, such as amending building codes to increase energy efficiency.

³⁷ Docket No. M-00061957, *Policies to Mitigate Electric Price Increases*, before the Pennsylvania Public Utility Commission.

³⁸ Statement of John Hanger, President and CEO, Citizens for Pennsylvania’s Future (PennFuture) before the Pennsylvania Public Utility Commission, June 22, 2006.

³⁹ Reply Comments of Energy Association of Pennsylvania before the Pennsylvania Public Utility Commission, July 20, 2006.

PPL Energy:⁴⁰ Customers need to be educated as to how POLR works and the relationship between demand and price. Conservation should be taught through programs such as LIURP.

PPL offers several proposals regarding POLR supply. EDCs should be on a common schedule, and the Commission should establish a tightly structured process for obtaining POLR supply. Portions of POLR supply should be purchased each year in order to phase in market prices. For example, one-third of power supply should be obtained in each of the three years preceding the start of POLR service. PPL also recommends that the staggered procurement process be structured similar to New Jersey's auction model. EDCs should procure energy from renewable resources at every tranche in order to meet obligations under the Alternative Energy Portfolio Standards (AEPS) Act. In addition, the PUC should not approve "opt out" customer aggregation (where a city or town becomes the default supplier for residents, and customers must affirmatively opt out of the municipal group).

West Penn Power (Allegheny Power):⁴¹ Customers won't change behavior until they are subject to market pricing signals, thus any transition period that phases in market-based rates should be brief. It should also be shorter for large commercial and industrial customers than for residential and small commercial customers. The competitive bid process, which allows the utility to conduct the bid subject to Commission review and monitoring, is cost effective. Allegheny prefers this process – as used in Maryland and Pennsylvania – to the New Jersey auction system.

March 2007 Comments on Obligation to Serve and Default Service⁴²

PPL Electric:⁴³ PPL supports the PUC's proposal to name the incumbent utility as the Default Service Provider (DSP); the PUC should only assign another entity as DSP for very compelling reasons. The PUC's proposal that DSPs file default service programs every two years would place a significant administrative burden on the commission. PPL believes that a statewide descending clock auction is a better approach to obtaining default service, but if the PUC requires individual utility plans, DSPs should try to coordinate their actions.

PPL does not believe that long-term contracts should only be used to achieve compliance with the AEPS Act. Long-term contracts could prove beneficial in other circumstances, and their use should be evaluated on a case-by-case basis.

⁴⁰ Comments of PPL Electric Utilities Corporation before the Pennsylvania Public Utility Commission, June 15, 2006.

⁴¹ Comments of West Penn Power Company, Doing Business as Allegheny Power before the Pennsylvania Public Utility Commission, June 15, 2006.

⁴² Docket No. L-00040169, *Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant to 66 Pa. C.S. §2807(e)(2)*, before the Pennsylvania Public Utility Commission, and Docket No. M-00072009, *Default Service and Retail Electric Markets*, before the Pennsylvania Public Utility Commission.

⁴³ Comments of PPL Electric Utilities Corporation before the Pennsylvania Public Utility Commission, March 2, 2007 (comments filed separately on same day for the two dockets).

PPL disagrees with the PUC's designation of three customer classes based on peak demand. Instead, PPL recommends that each DSP be allowed to develop its own customer class designations based on the utility's rate schedules and demographics.

Allegheny Power:⁴⁴ Allegheny recommends allowing DSPs to use either the New Jersey reverse auction model or the Maryland Request for Proposals (RFP) model to obtain supply. PJM's wholesale suppliers are familiar with both and thus can adapt to either one. With either design, offers should be evaluated using the lowest price as the decision criterion. Giving DSPs a choice of these two models is better than a model that incorporates multiple procurement methods because the portfolio approach increases both regulatory risk and the administrative burdens for regulators, utilities, and suppliers.

Both the auction and RFP models can include supply contracts of different lengths and separate bids for different customer class. In regard to the question of how frequently default service prices should change, the goal is to find a balancing point that reduces price volatility while also ensuring some measure of price responsiveness.

Default service standards are not the proper means to promote fuel diversity. State and regional programs are better suited because fuel diversity goals set for individual utilities are too expensive and inefficient.

The use of price caps to protect customers during a transition period has three major flaws: alternative suppliers can't compete; the artificially low prices undercut demand response programs; and it is difficult for customers to adjust to large rate increases that can occur upon expiration of the price cap.

PennFuture:⁴⁵ PennFuture proposes that the Commission require, rather than encourage, DSPs to incorporate demand side resources and energy efficiency resources in their portfolios. Additionally, more specific language is needed to assure DSPs that they will recover costs if they enter into long-term contracts to procure alternative energy. The PUC should also mandate that at least 10 percent of default service load be enrolled in voluntary real-time pricing programs. Finally the PUC should require utilities to propose revenue decoupling programs in order to encourage energy efficiency.

Office of Consumer Advocate:⁴⁶ OCA supports the use of a portfolio of demand and supply resources to provide default service and believes that acquiring diverse resources through various methods and over a reasonable time period will provide a hedge against a number of risks. Sole reliance on a mechanical process – such as an auction similar to the New Jersey model or RFPs set for specific time periods – is not likely to achieve the lowest cost power for consumers. However, either of these methods could be useful in

⁴⁴ Comments of Allegheny Power before the Pennsylvania Public Utility Commission, March 2, 2007.

⁴⁵ Comments of Citizens for Pennsylvania's Future before the Pennsylvania Public Utility Commission, March 2, 2007 (comments filed separately on same day for the two dockets).

⁴⁶ Reply Comments of the Office of Consumer Advocate before the Pennsylvania Public Utility Commission, March 23, 2007.

obtaining a portion of supply. OCA also supports the use of bilateral contracts negotiated with non-affiliated generation owners as part of a portfolio.

Final Orders and Policy Statement⁴⁷

In May 2007 the PUC issued final orders on policies to mitigate potential price increases and the obligation to serve customers at the conclusion of the transition period. The PUC also issued a final policy statement on default service.

The PUC adopted a plan to implement a five-year, \$5 million state-wide program to educate consumers about energy conservation and efficiency measures, the ending of the transition period, and the potential to receive energy from alternative suppliers. The program will be paid for through an assessment on electric utilities, and the utilities can recover this cost through customer rates. In addition to the state-wide program, EDCs will implement consumer-education programs in their own territories.

The PUC determined that the public interest is best served when regular adjustments are made to default service so that it tracks with the actual prices incurred by DSPs. This ensures that customers do not experience large fluctuations in prices at the end of the program term. A small series of rate increases are better than one large increase. Thus DSPs should consider a portfolio of products, including a mix of fixed term and spot market energy purchases, laddered contracts, and demand resources, rather than procure all supply needs at one time. This reduces the risk of acquiring a significant portion of supply when prices are unusually high or volatile. In the case of large rate increases, DSPs should provide customers the option of deferring part of the increase for as long as three years.

The PUC's policy statement recommends that DSPs increase their reliance on short-term and spot purchases over time. The PUC discourages the use of long-term and bilateral contracts because it is skeptical of utilities' ability to beat the market price or correctly anticipate changes in market prices. However, longer-term contracts can make the transition to market rates smoother in the years right after rate caps expire.

Utilities must phase out declining block rate tariffs. Default service customers will be provided a single rate option, called the Price-to-Compare (PTC). The PTC combines generation and transmission costs and provides customers with the appropriate information to compare default service with alternative suppliers' offers. In addition, the PUC may separately determine that DSPs should also offer customers a time-of-use rate.

⁴⁷ For PUC press release, see http://www.puc.state.pa.us/general/press_releases/press_releases.aspx?ShowPR=1754.