STATE ANALYSIS AND SURVEY ON RESTRUCTURING AND REREGULATION

Final Report

Prepared by Kaye Scholer LLP
Levitan & Associates, Inc. and
Semcas Consulting Associates
In Response To Task #2
Request for Proposals PSC #01-01-08

For Maryland Public Service Commission

December 1, 2008

TABLE OF CONTENTS

TABLE OF ACRONYMS

1997 Ill. Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997, Ill. Pub. Act 90-561
1998 CT Act	An Act Concerning Electric restructuring, Conn. Pub. Acts 98-28
1999 Md. Act	Maryland's Electric Customer Choice and Competition Act of 1999
ACP	Annual Contact Price
AEP-Virginia	American Electric Power-Virginia
Ameren Companies	Ameren CILCO, AmerenCIPS and Ameren IP
AmerenCIPS	Central Illinois Public Service
AmerenEnergy	AmerenEnergy Resources Generating Company
BGE	Baltimore Gas & Electric
BGS	Basic Generation Service
BGS-CIEP	Basic Generation Service Hourly-Price Plan
BGS-FP	Basic Generation Service Fixed-Price Plan
Bluewater	Bluewater Wind LLC
CEA	Connecticut Energy Authority
CEAB	Connecticut Energy Advisory Board
CEEE	Concerning Electricity and Energy Efficiency
CfD	Contract for Differences
CL&P	Connecticut Light and Power Company
CL&P 2000 10-K	Connecticut Light and Power Company, Annual Report
ComEd	Commonwealth Edison Company

Commission, PSC	Maryland Public Service Commission
Connectiv	Connectiv Energy Supply, Inc.
CT DPUC	Connecticut Department of Public Utility Control
CTCs	Competitive Transition Charges
CTR	Capacity Transfer Rights
DE PSC	Delaware Public Service Commission
DEC	Delaware Electric Cooperative
Delmarva	Delmarva Power & Light Company
DSM	Demand-Side Management
EDCs	New Jersey's Four Electric Utilities (PSE&G, JCP&L, Connectiv and Rockland)
EDECA	Electric Discount and Energy Competition Act, N.J. Public Law 1999
EIA	An Act Concerning Energy Independence, Conn. Pub. Acts 05-1 (Spec. Sess. 2005)
EME	Edison Mission Energy
EMP	New Jersey's Energy Master Plan
EPACT 1992	Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992)
EWG	Exempt Wholesale Generator
Exelon	Exelon Energy Co., LLC
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FMCCs	Federally Mandated Congestion Charges

FPA	Federal Power Act, 16 U.S.C. §§ 791-828c (2000)
Genco	AmerenEnergy Generating Company
ICC	Illinois Commerce Commission
IPA	Illinois Power Agency
IRPs	Integrated Resources Plans
ISO	Independent System Operators
ISO-NE	ISO New England
JCP&L	Jersey Central Power & Light
LCIRP	Least Cost Integrated Resource Plans
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Prices
LRS	Last Resort Service
Md. OPC	Maryland Office of People's Counsel
MISO	Midwest Independent Transmission System Operator
NGPA	Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3432 (2000)
NH PUC	New Hampshire Public Utility Commission
NJ BPU	New Jersey Board of Public Utilities
NRG	NRG Energy, Inc.
O&M	Operations and Maintenance
OASIS	Open Access Same-time Information System
OPSI	Organization of PJM States, Inc.
PAT	Price Anomaly Threshold

PEPCO	Potomac Electric Power Company
Potomac Edison	Potomac Edison Company
PPA	Power Purchase Agreement
PPO	Power Purchase Option
PSA	Power Supply Agreement
PSE&G	Public Service Electricity & Gas
PSNH	Public Service of New Hampshire
PUHCA	Public Utility Holding Company Act of 1935, 15 U.S.C. §§ 79-79z-6 (2000)
PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-2645 (2000)
QFs	Qualified Facilities
RFP	Request for Proposal
RMD	Office of Retail Market Development
RMR	Reliability Must Run
Rockland	Orange & Rockland Electric
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SEU	Sustainable Energy Utility
SO	Standard Offer
SOS	Standard Offer Service
SS	Standard Service
State	Maryland
SWCT	Southwest Connecticut

SWMAAC	Southwest Mid-Atlantic Area Council
TSO	Transitional Standard Offer
UI	United Illuminating Company
Virginia Power	Dominion Virginia Power
VRR	Variable Resource Requirement
WPPSS	Washington Public Power Supply System

TASK 2:
STATE ANALYSIS AND SURVEY ON RESTRUCTURING AND RE-REGULATION

I. Executive Summary

Beginning in the 1990s, the wave of state and federal initiatives to restructure the electric industry swelled based on expectations of lower retail rates, new generation that would apply innovative technologies, and retail customers' opportunity to choose among aggressively competing merchant power suppliers. Economists and policy makers concluded that regulated utilities no longer had to be vertically integrated – *i.e.*, owning generation, transmission, and distribution assets and recovering their full costs of service from retail customers. Congress and the Federal Energy Regulatory Commission ("FERC") opened the door to competition in generating power – first from certain qualified facilities and later more broadly to a range of wholesale electricity producers – by requiring open access to transmission and assuring recovery of utilities' stranded costs. Many states followed suit by requiring utilities to separate ownership of generation from transmission and distribution and permitting retail competition for generation supply.

Restructuring's promise has been largely unfulfilled, however. Retail competition, particularly for residential customers, has not developed as intended. Rather, utilities continue to purchase wholesale power to supply their load, and most residential customers opt for that default service. Wholesale markets have not reliably provided merchant generators with appropriate incentives to build new power plants when, where, and how they are needed. Consequently, investors built mostly gas-fueled peaking and intermediate units, not base load. Moreover, evolving environmental requirements have made renewable generation resources and demand response more significant components of states' energy plans, but existing competitive markets have proven less than optimal for their development. Finally, once rate freezes and roll backs expired, customers had to pay steeply increased market-based costs that reflected rising fuel prices. Although other factors may have contributed to these rate shocks, some blamed deregulation, and it is indisputably true that electric rates have not declined from the prices at the time restructuring regulations became effective, as many had anticipated. In the wake of these disappointing results, several states have rued their optimistic forays into restructuring and have instead adopted new, enhanced regulatory measures that are designed to assure appropriate power plant development and to control retail customers' electric energy costs.

Maryland has reached a similar, critical juncture. In order to evaluate the State's options, we examined in greater depth the restructuring history for four states – Connecticut, Delaware, Illinois, and New Jersey. While their individual experiences vary, they have adopted four primary approaches to restore the states' influence over electric rates and new generation construction. First, states have directed utilities to enter long-term contracts for new generation facilities or to build their own generation units to be included in cost-of-service rates. Second, states have recognized the need for integrated energy planning that accounts for demand growth, energy efficiency initiatives, transmission enhancements, environmental protections, and new generation and have assigned responsibility for those comprehensive plans to utilities and state regulatory commissions. Third, some states have created new public power authorities with a range of responsibilities, from planning and public education to outright ownership of new generation. Fourth, states have recognized the interrelation between wholesale and retail power markets and have taken a much more active role in shaping and directing federal energy policies that have a direct impact on the states.

We have assessed the efficacy of these and other approaches for Maryland within the context of expected costs, risks, and benefits. Retail customers will always bear the ultimate costs for producing electricity to serve the required demand, and irreducible uncertainty about the future creates an element of investment risk. Thus, regardless of whether utilities own new generation or agree to buy its long-term output from merchants, customers must pay someone to assume those risks, and rates will necessarily reflect those costs. Nevertheless, proper allocation of costs and risks among the relevant parties can improve efficiency and reduce overall costs. In considering its options going forward, the State must determine the appropriate balance of direct costs and risks that will achieve its objectives, and we examined the pros and cons for five possible re-regulation approaches.

First, the State could require utilities to repurchase previously divested generation resources or to construct new generation sufficient to replicate that divested capacity – *i.e.*, return to the same vertically integrated structure that existed before 2000. While this tack would reestablish the State's direct control over power production, it would also transfer cost responsibility to customers for all resource planning decisions. Moreover, the immediate costs of returning to full regulation would be very substantial. Utilities or a state power authority would have to pay current market value for the previously divested generation assets, and traditional cost-of-service rates based on depreciation and a return on utilities' capital investments will require higher retail rates in the near term but could lower costs over the life of the generation assets. The Commission might adopt other ratemaking paradigms (*e.g.*, incentive or benefit-sharing rates) to soften the impact, but under any scheme, utilities' rates must cover a return of and on their investments. The full re-regulation option will require an unprecedented initial investment, places all risks on retail customers, and could be more difficult as a consequence of the current credit market. No other state has pursued this course.

Second, the State could direct utilities to enter intermediate- and long-term contracts with new generation developers. This route provides great flexibility to tailor procurement to meet the State's needs. For example, long-term contracts might be used (1) to diversify Maryland's fuel mix and improve environmental performance by emphasizing renewable resources, demand response, or efficient base load units, (2) to lower energy and capacity charges in Maryland by adding lower-cost resources in areas where prices are currently high, (3) to stabilize and moderate retail prices for an extended period, (4) to assure new generation capacity when and where it is needed, or (5) to address market power concerns in the Southwest Mid-Atlantic Area Council ("SWMAAC") by awarding contracts to new generation owners. The State may choose among an assortment of contract types and forms that have proved effective, but it may prove advantageous to procure both energy and capacity through mechanisms that permit customers to capture the asset's full value. The State may also design an open bid process that will identify the most favorable contract length to give some certainty while preserving a degree of flexibility.

Third, the State may create an independent power authority with a range of powers to manage the State's energy programs. A power authority can provide a focal point for planning, coordinating, and directing diverse objectives. Not surprisingly, the current hodgepodge of responsibilities divided among the State (including multiple agencies with power-related mandates), FERC, utilities, PJM, and merchant generators creates both overlaps and gaps. At the least, a single authority might be able to harmonize some of those interests for customers' benefit. It could also assume more expansive duties, including direct ownership of generation facilities, procurement of default service, or stimulation of renewable and demand resources. The more responsibility a power authority assumes, however, the greater risks customers will bear, particularly when the State must create a fully staffed organization and procedures from scratch.

Fourth, the State might reinvigorate the dormant integrated resource planning functions previously assumed under regulation by state commissions and utilities. No entity, however, currently has broad responsibility to develop Maryland's long-range, comprehensive expectations about load growth, available generation resources, environmental consequences, and transmission improvements. These elements of the electric system obviously interact, but the State cannot manage rate implications for customers without a unified plan. Utilities, with the State's assistance and direction, can assemble compatible data that will facilitate informed decisions. Such integrated planning entails little risk and can produce significant benefits.

Fifth, regardless of the State's efforts to recapture control of the retail components of the electric industry, it will remain vulnerable to federally regulated wholesale power markets. The State can direct or stimulate new generation construction and thereby influence wholesale market prices, but existing or proposed rules in those markets may continue to frustrate the State's needs. The division of state and federal regulatory authority over the electric industry creates inevitable opportunities for frictions that can only be addressed effectively if the states express their concerns forcefully in the federal forum. If Maryland becomes a significant participant in federal proceedings that affect its retail customers, it can influence the structure and rules for PJM's wholesale markets and protect the State's vital interests. The PSC has taken aggressive steps to assert its role in the development and implementation of federally regulated, wholesale markets.

None of the individual re-regulation options that we outline provides a complete solution to Maryland's concerns. Further work will be required to ensure that the approaches chosen will create an appropriate balance of risks, costs, and benefits.

This Final Report updates and supplements the Interim Report issued on November 30, 2007. It reflects input from the General Assembly, developments over the past year, and further analytical analysis of possible options for Maryland's generation future.

II. Background

A. Historical context

For nearly a century, the electricity industry was comprised of state-regulated, vertically integrated utilities. Before and after the Great Depression economists and lawyers pointed to the pervasiveness of monopoly elements throughout the economy. By the 1930s Congress passed comprehensive legislation to protect the public from potential monopoly abuse by public utilities, *i.e.*, the Public Utility Holding Company Act of 1935 ("PUHCA"). Both federal and state laws evolved to protect a public utility's franchise area, where only one company generated, transmitted, and distributed electricity, subject to traditional rate-of-return regulation. For the most part, state regulatory commissions throughout the U.S. ensured that the public utilities were able to collect their costs as well as earn a reasonable rate of return on their investment. Traditional cost-of-service regulation continued unimpaired for nearly three decades after World War II until higher fossil fuel costs and uncertainty about nuclear power caused Congress in the late 1970s to introduce competition in electric generation. Technology improvements, including development of efficient gas turbines, coupled with national interest in renewable technologies, stimulated landmark federal legislation in 1978. Policy makers at both the state and federal levels saw deregulation as a means to introduce competition and reduce electric rates. Since the late 1970s, modified regulating structures have facilitated competition in the generation function, while the "wires" function related to the transmission and distribution of electricity has remained subject to traditional cost-of-service regulation.

1. The Public Utility Regulatory Policies Act of 1978

Congress intended the 1978 Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. § 824a-3 (2006), to provide access to the power grid for lower-cost competitors and to limit the amount of generation that entities affiliated with the integrated utility could own. Congress passed PURPA in response to the unstable energy climate of the late 1970s, including concerns about reliance on foreign oil, the domestic natural gas supply, and energy conservation. PURPA created a new class of qualified facilities ("QFs") – both small power producers and cogenerators – and required investor-owned utilities subject to individual state regulation to purchase the generation output from QFs at the utility's "avoided costs," *i.e.*, the costs that the regulated utility would have otherwise incurred if it had built a generation plant under traditional cost-of-service regulation. In conjunction with the Natural Gas Policy Act ("NGPA"), also passed by Congress in 1978, Congress sought to encourage more exploration and development of natural gas throughout the U.S. as well as the development of more efficient resource alternatives – *e.g.*, natural gas-fired cogeneration, hydrogenation, and wind. Under the NGPA and PURPA, Congress sought to blunt the rising costs of traditional vertically integrated fossil-fueled generation.[1] PURPA expanded QFs' participation in the wholesale electricity market, adding many tens of thousands of megawatts of QF to the utilities' resource mix throughout many parts of the U.S., including Maryland. As a means of stimulating development of alternative suppliers, PURPA required utilities to enter long-term contracts with QFs.[2]

2. Energy Policy Act of 1992 ("EPACT 1992")

The Energy Policy Act of 1992[3] ("EPACT 1992") created a new category of electricity producer, the exempt wholesale generator ("EWG") and required FERC to open the national electricity transmission system to wholesale suppliers on a case-by-case basis. EPACT 1992 created a competitive wholesale framework for giving wholesale power generators – *i.e.*, any generator that sells power for resale to retail customers – open transmission access. The law made EWGs exempt from PUHCA, thereby facilitating their ability to transmit power to wholesale purchasers.[4]

EPACT 1992 accelerated the transformation of the wholesale power industry by creating a competitive generation model for wholesale electricity supply.[5] A more vigorous competitive wholesale market placed the risks and rewards on the generation owner and, together with federal and state regulatory changes, placed a greater premium on efficiency.[6]

3. FERC Order Nos. 888 and 889

FERC's landmark 1996 Order Nos. 888 and 889 played a further key role in opening the U.S. energy market to competition.[7] Order No. 888 required traditionally

---

1 *See* Peter M. VanDoren, *The Deregulation of the Electricity Industry: A Primer* (Oct. 6, 1998) (*available at* http://www.cato.org/pubs/pas/pa-320.pdf) at 5-6.

2 *See* Federal Energy Regulatory Commission, http://www.ferc.gov/students/energyweregulate/fedacts.htm; see also, Sheldon Switzer and Mary M. Straub, The Benefits of Restructuring: It's Not Your Grandfather's Electric Utility Anymore, 19 Elec. J. 30 (Feb. 2006) ("Switzer and Straub") at 33.

3 Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992).

4 *See* http://www.ferc.gov/students/energyweregulate/fedacts.htm; *see also*, Switzer and Straub at 37-38.

5 Switzer and Straub at 34.

6 *Id.*

7 Order 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Public Utils.*, FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996, ¶ 31,036, 61 Fed. Reg. 21,540 (May 10, 1996); Order 889, *Open Access Same-Time*

integrated utilities to unbundle generation services from the transmission and distribution functions. Order Nos. 888 and 889 gave utilities incentives to separate marketing functions for newly-disaggregated services, required utilities to provide open access to their transmission facilities through published tariffs, and gave utilities the right to recover their stranded costs from retail customers.

Following its success deregulating the natural gas, FERC emulated that paradigm in Order No. 888 by requiring transmission owners to offer transmission service on an open access, non-discriminatory basis.[8] Soon afterward, Order No. 889 set standards for information that utilities must make available to the marketplace and established the Open Access Same-time Information System ("OASIS"), an internet bulletin board designed to permit market participants to share data. OASIS allowed wholesale market participants to schedule and reserve capacity on the regional grids to ensure that energy could be delivered to customers without competitive interference. FERC Order 889 prohibits utilities from sharing market information in any way that impedes access by potential competitors, and requires timely posting of extensive market data relating to scheduling energy in the day-ahead and real-time markets.

FERC hoped that open access would facilitate delivery of lower cost power to electric consumers, ensure continued reliability of the electric power industry, and provide for open, fair electric transmission services. FERC expected its actions to create cost savings of $3.8 to $5.4 billion per year, foster better use of existing assets and institutions, facilitate new market mechanisms, promote technical innovation, and produce less rate distortion.[9]

In its final rule, FERC adopted a single pro forma tariff describing the minimum terms and conditions of service to establish this non-discriminatory open-access transmission service. All public utilities that own, control, or operate interstate transmission facilities were required to offer service to others under the pro forma tariff, which also applied to the utilities' own wholesale energy sales and purchases. Order No. 888 further provided for the full recovery of stranded costs, *i.e.*, costs that were prudently incurred to serve power customers and that the utility would not recover if its customers use open access to move to another supplier.[10]

Information System and Standards of Conduct, FERC Stats. & Regs. Preambles, Jan. 1991-June 1996, ¶ 31,035, 61 Fed. Reg. 21,737 (Apr. 24 1996).

8 Ronald J. Sutherland, *Restructuring Electricity Markets: An Application to the PJM Region*, Center for the Advancement of Energy Markets (CAEM) (Sept. 2003) at 17.

9 *See* Amy Abel, *Transmission Issues, FERC Orders 888 and* 889, Congressional Research Service (Oct. 2000) (*available at* http://www.ncseonline.org/nle/crsreports/briefingbooks/electricity/ebeleti.cfm).

10 *See Commission Orders Sweeping Changes for Elec. Util. Indus. Requires Wholesale Mkts to Open to Competition* (July 2003) (*available at* http://www.converger.com/FERCNOPR/888_889.htm).

B. The Economic Debate Over Deregulation

1. The Impetus for Deregulation

For over a century, economists, lawyers, academics, and regulators understood that electricity markets differ from other markets. The distinct physical and economic characteristics help explain how states structured their deregulated markets, the problems that arose, and how states have attempted to re-regulate electric generation. Other than pumped storage hydrogeneration plants, electricity cannot be stored but must be generated and transmitted as needed.[11] In addition to having to be produced "just-in-time," electricity is transmitted over lines that have physical capacity limits and complex interaction effects. To ensure safe and reliable operation, transmission lines must be monitored to maintain frequency, voltage, and stability.[12] In the short-term, the demand for electricity is inelastic, *i.e.*, consumers do not reduce usage at high demand levels when generation plants and transmission lines are operating at or near design capacity. Because electricity must be generated just-in-time, some plants must be available even though they are used infrequently – only when demand approaches its peak – and must be paid during the short periods when they are needed so that they recover all of their costs. Finally, generators must work in tandem with regulated transmission networks to use scarce transmission capacity.

Moreover, the states and federal government split regulatory responsibilities in the electric market, with the states regulating primarily the retail sector and the federal government regulating primarily the wholesale market and interstate transmission. The jurisdictional limits are not always clearly demarcated, and actions in one market invariably affect the other. Retail electric markets are, therefore, heavily influenced and often constrained by FERC actions affecting the behavior and participation of generation companies, transmission owners, and third-party market participants engaged in wholesale transactions. Economists agree that retail competition can only be successful if there is a competitive wholesale market,[13] but it does not follow that a workably competitive wholesale market will itself assure retail competition. State regulatory commission actions and incentives also provide important elements to stimulate competition at the retail level.

As wholesale markets developed, calls for retail market reforms intensified. The transformation of regional power pools into Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") – which fostered the creation of energy and ancillary services markets for generation services – and Standard Market Design led

---

11 Paul L. Joskow, *The Difficult Transition to Competitive Electricity Markets in the U.S.*, Joint Center AEI-Brookings Joint Center for Regulatory Studies (July 2003) ("The Difficult Transition") at 10.

12 *Id.*

13 Paul L. Joskow, *Deregulation and Regulatory Reform in the U.S. Electric Power Sector*, Deregulation of Network Industries: The Next Steps (S. Peltzman and Clifford Winston, eds., Bookings Press 2000) at 176.

to Locational Marginal Pricing ("LMP"). The LMP framework, accepted by many state commissions seeking to promote wholesale market competition, reflected the market value of energy by location. By differentiating the value of energy on a locational basis, the effect of transmission capacity constraints and congestion could be explicitly included in setting the energy price each day.

FERC issued Order 2000 in December 1999, to facilitate the creation of RTOs.[14] FERC anticipated that RTOs would organize and coordinate the various transmission networks across the United States.[15] Certain provisions of Order 2000 were particularly significant in developing competitive wholesale markets, including: (a) creating transmission system operators that were to be independent from generators and transmission owners, (b) creating large regional power markets with common transmission access and pricing rules and common wholesale markets to mitigate inefficiencies associated with many transmission owners; and (c) creating basic wholesale market institutions to support buying and selling power economically and allocating transmission capacity efficiently.[16] These provisions and incentives have made transmission more accessible to independent generators, marketers, financial entities, and utilities on standardized terms.

Similarly, the LMP pricing paradigm makes transmission constraints more transparent, thereby signaling where new generation is most needed to alleviate congestion. LMP uses "nodal" or locational pricing to identify areas with greater congestion constraints. Through a uniform price, multi-unit auction framework, the market integrates day-ahead, hour-ahead, and real-time prices, with the allocation of scarce transmission capacity.[17] This transparency further helped wholesale markets to develop because any potential entrant could determine where additional capacity was needed.

Calls for deregulation arose as electricity price discrepancies developed between different regions of the country. A legacy of costly nuclear power plants and long-term contracting decisions made during the 1970s and 1980s[18] produced higher prices in California and the Northeast, while prices in the Pacific Northwest and Southeast were

---

14 Regional Transmission Organizations, 89 FERC ¶ 61,285 (1999); Paul L. Joskow, *Markets for Power in the United States: An Interim Assessment*, 27 Energy J. 1 (2006) (*available at* www.econ-www.mit.edu/centers/wel/marketsjoskow.pdf) ("Joskow Interim Assessment") at 4.

15 Joskow Interim Assessment at 4.

16 *Id.* at 5.

17 *Id.* at 8.

18 Paul L. Joskow, *Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector*, 11 J. of Econ. Perspective 3 (Summer 1997) at 126.

comparatively low.[19] Similarly, a gap developed between the regulated price of generation service and the wholesale market value of those services.[20]

As this gap grew, economists argued that generating plants no longer needed to be regulated because they were no longer natural monopolies. Nevertheless, viable competition depends on avoiding the dangers of vertical and horizontal anticompetitive conduct. First, merchant generators must operate separately and independently from regulated transmission and distribution utilities. This would require utilities to divest their generation assets to unaffiliated entities or to impose strict codes of conduct that would preclude collusion between utilities and their generation affiliates. Second, generation owners could not be permitted to exercise improper market power in locations where they are dominant. Thus, wholesale markets had to be designed and monitored to identify and mitigate generator behavior that could stifle competition, *e.g.*, through imposition of price or bid caps. As Congress and FERC took steps to open markets, to protect against market power abuse, and to assure recovery of any stranded costs caused by restructuring, deregulation became more attractive for both utilities and merchant generators.

Proponents of deregulation believed that competitive wholesale markets would provide better incentives for controlling costs of new and existing generating capacity, encourage innovation in power supply technologies, and shift the risks of technology choice, construction cost, and operating or economic mistakes to suppliers and away from consumers.[21] For example, under the regulated regime, retail customers paid for all construction and operating costs, except those that were incurred imprudently. The burden of proving imprudence, however, was high. Consequently, utilities were not always penalized for construction management failures or for inefficient operating performance.[22] There was also a concern that the centralized, administrative resource planning process had become overly-politicized. In its place, proponents expected deregulation to create "an environment that stimulates the lowest cost generation sources, consistent with environmental regulations."[23] The envisioned deregulation framework would give generators economic incentives to retire old, uneconomic, environmentally harmful plants.[24]

Deregulation advocates similarly expected retail competition to allow customers to choose the supplier offering the price/service/quality combination that best met their needs. Competing retail suppliers would provide an enhanced array of retail service products, risk management, demand-side management ("DSM"), and new opportunities

---

19 *Id.*

20 *The Difficult Transition* at 5.

21 *Id.* at 7.

22 *Deregulation and Regulatory Reform in the U.S. Electricity Sector* at 121.

23 *Id.*

24 *Id.* at 122.

for service/quality differentiation (*e.g.,* “green” power) based on individual consumer preferences.[25] Moreover, if consumers responded to high prices by using less electricity, thereby signaling an interest in energy-saving products, equipment manufacturers would develop new appliances and equipment capable of exploiting opportunities for energy conservation.[26] If consumers had access to real time pricing data, they could adjust their consumption to reflect changing electricity prices, thereby aligning prices with the relevant marginal costs.[27]

Since the onset of utility divestiture in the late 1990s, wholesale electricity prices have risen substantially, particularly in regions that rely primarily on natural gas and oil as a primary fuel to produce electricity. Other design failures in wholesale markets may also serve to explain part of the increase in wholesale electricity prices. In a competitive market, prices fluctuate as supply and demand conditions change. Properly designed and implemented competitive markets should provide sufficient stability and certainty to minimize price volatility, but even then deregulated prices may sometimes exceed expected regulated prices. Those occasions should not warrant cries for regulation, however, because, in theory, correctly functioning competitive markets should produce lower long-run prices.

2. <u>Concerns Raised About Deregulation</u>

Not all economists agreed with the arguments in favor of deregulation. Some argued that the demand for electricity is almost completely inelastic, meaning that consumers are unlikely to use less electricity as prices rise.[28] “Demand side responsiveness to price [, however,] is essential to the operation of a restructured market.”[29] Increasing demand side responsiveness would require giving customers real-time prices of electricity, which would require capital investments for purchasing, installing, and maintaining the necessary equipment, and these costs could be greater than the costs of building additional generating capacity.[30]

Some economists posit that problems in deregulated markets occur in part because markets are not fully deregulated. Market imperfections and institutional constraints still keep wholesale prices for energy and operating reserves below their efficient levels during hours when prices should be very high. These price caps can

---

25 *The Difficult Transition* at 7.

26 *Deregulation and Regulatory Reform in the U.S. Electric Sector* at 123.

27 *See Id.*

28 Price C. Watts, *Heresy? The Case Against Deregulation Of Electricity Generation*, 14 Elec. J. 19 (May 2001) at 20.

29 *Id.* (citing Alfred E. Kahn, Peter C. Cramton, Robert H. Porter, and Richard D. Tabors, *Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?* Blue Ribbon Panel Report, California Power Exchange (Jan. 23, 2001) at 16).

30 *Id.* at 21.

undermine investment incentives in new generation because new suppliers believe that the caps will prevent them from recovering the costs of building new generation.[31] Unless replaced through other mechanisms like separate payments for "capacity," this "missing money problem" arguably contributes to the ineffectiveness of normal market-based risk allocation mechanisms. Moreover, continued reforms in the wholesale market design and rules – as well as calls for re-regulation – promote further uncertainties and an incomplete transition to a stable retail competition framework.[32]

In the regulated regime, utilities received defined rates of return on their capital investments.[33] These opportunities to earn guaranteed returns allowed utilities access to lower-cost capital because lenders and investors assumed minimal default risk when state commissions provided a regulatory assurance that the utility would have an opportunity to recoup its costs and realize a reasonable return on equity.[34] In the deregulated regime, however, merchant generators no longer have access to inexpensive capital because they incur the risk of underrecovery in response to construction, operating, financial, business, and market risks.[35] Some merchant generators must rely on private equity and other sources of venture capital, and because returns are not guaranteed, the debt for those power projects is not investment grade. Bankruptcies at Calpine, Enron, NRG and Mirant and the general credit implosion continue to affect the cost of money. This higher cost of capital encourages potential entrants to build plants with lower capital costs but higher operating costs.[36] The same financial bubble that buoyed internet and telecom stocks in the late 1990s and early 2000s gave merchant generators brief access to inexpensive capital, allowing some plants to be built, but such capital is no longer available.[37]

Skeptics argued that wholesale power markets would not provide appropriate long-term pricing signals to bridge the gap created by eliminating assured cost-of-service recovery under regulation. Energy markets can send effective real-time signals to guide unit dispatch decisions to reward the most efficient facilities, but those short-term prices cannot support long-term capital investment decisions. Because capacity investment decisions have multi-decade ramifications, they require decade-plus pricing signals that deregulated markets do not typically provide.

---

31 Paul L. Joskow, *Competitive Electricity Markets and Investment in New Generating Capacity*, (June 12, 2006) at 4.

32 *Id.* at 5.

33 *Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector* at 126.

34 *Heresy? The Case Against Deregulation Of Electricity Generation* at 20.

35 *Id.*

36 *Id.*

37 *The Difficult Transition* at 17.

Some economists also expressed concerns over whether deregulation proposals had adequately addressed market power concerns.[38] Because utilities historically operated as monopolies, they could exercise market power in a deregulated market absent stringent safeguards. The electric market is vulnerable to market power abuses because electricity must be generated at the instant it is needed. There is essentially no short-run elasticity of demand for electricity.[39] Thus, any generator with more capacity than the excess of capacity over demand can exercise market power.[40] Tacit collusion to exercise market power is all the more likely when the same generators participate in daily auctions.[41]

Deregulating the electric markets also requires independent generators to work with regulated transmission owners in developing the transmission grid, although the two stakeholder groups may have decidedly conflicting agendas.[42] In the regulated regime, state regulators, utilities, and regional power pools made grid expansion decisions in the context of integrated resource planning.[43] Coordination was straightforward because the same entities owned generators and transmission lines. In a deregulated regime, however, generation expansion plans are temporarily trade secret and only become transparent through an arcane, multi-phase interconnection process that can take years to resolve and still more time to reconcile with competing transmission expansion project proposals. Different transmission projects inevitably favor different market participants, and new transmission projects invariably enhance the value of some generation assets while reducing the value of others.[44]

Deregulation also introduced a new element of uncertainty because customers could switch among competing suppliers, based on price, service, reputation, or perceived quality of service.[45] Thus, if a local utility entered a long-term contract with a generator, and another supplier offered a lower price, the utility's retail customers could switch to the lower-priced supplier. This prospect of customer migration to different

38 *See, e.g.*, Alex Henney, *Contrasts in Restructuring Wholesale Electric Markets: England/Wales, California, and the PJM*, 11 Elec. J. 24 (Aug./Sept. 1998) at 32 (noting that report submitted by the PJM Operating Companies does not address the "critical" issue of market power in units that control the margin).

39 *Heresy? The Case Against Deregulation Of Electricity Generation* at 21.

40 *Id.*

41 *Id.*

42 *Id.* at 21-22

43 *Id.* at 22.

44 *Id.*; *See* Paul L. Joskow, *Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry*, Brookings Papers on Economic Activity: Microeconomics (1989) at 187 ("Perhaps the primary issue that has not been addressed adequately is whether increased reliance on third party generation will eventually create problems of coordination and reliability that are handled more efficiently when generation, transmission, and distribution are under common ownership and where cooperation rather than competition is the norm").

45 *Heresy? The Case Against Deregulation Of Electricity Generation*, at 22.

suppliers discouraged long-term contracts, and consequently foreclosed the best available hedge against short-term price volatility and market power in the spot market.[46] Similarly, fear of customer switching increases the costs of constructing new generation because the generator cannot guarantee enough customers to repay the loan or avoid bankruptcy.

C. Creating Appropriate Incentives

As we detail below, states that deregulated their electric markets did not reap the expected benefits, largely because generators and consumers did not respond as states expected. This recent experience is a stark reminder that the success or failure of deregulation depends in large measure on the extent to which market designs provide the appropriate incentives for merchant generators and transmission owners to expand capacity.

Following deregulation, energy-only wholesale markets did not produce sufficient net revenues to support investment in new generating capacity where it was needed.[47] In PJM, for example, between 1999 and 2004, a new peaking unit would not have earned enough net revenues from sales of energy and ancillary services to cover its fixed costs.[48] Even with capacity revenues, the new plant would not meet the fixed costs that investors would expect to recover to make the investment profitable.[49] To succeed, deregulated markets must send adequate investment and demand reduction signals to assure a reliable, efficient generation supply.

Similarly, for retail deregulation to succeed, customers, utilities, and merchant suppliers need incentives to enter long-term arrangements that will provide stability and assure recovery of long-lived generation assets. Two aspects of deregulation have frustrated these objectives. First, when customers can opt for default service that reflects market prices − *e.g.*, Maryland's Standard Offer Service ("SOS") − merchant suppliers will have little opportunity to compete because they cannot offer below-market prices, and customers will have little motivation to choose higher-cost alternatives. Without some gap between the default price and market price, retail competition will not develop. Second, otherwise desirable long-term contracts become problematic for load-serving entities and suppliers if customers can readily switch to lower-cost suppliers whenever market prices drop. Moreover, if market prices increase over the course of a long-term contract (or during a price cap period), customers will face a dramatic rate shock when they must pay market prices again, as inevitably, they must.

---

46 *Id.*

47 Joskow Interim Assessment at 15.

48 *Id.* at 16.

49 *Id.* Note, however, that PJM's Reliability Pricing Model ("RPM"), initiated in 2007, provided sufficient additional revenues for generators in Maryland to recover the costs of new entry. PJM Market Monitoring Unit, 2007 State of The Market Report (March 4, 2008) ("2007 State of the Market Report"), Vol. II, at 136.

D. States' Experiences With Deregulation

Overall, states have had similar experiences with deregulation, with many of them experiencing some degree of "buyer's remorse." These similarities stem from the fact that most deregulated states are in the Northeast and Midwest,[50] and most followed parallel paths to deregulation.

1. Divestiture Requirement

Except for Michigan, every state that deregulated allowed its utilities to divest some or all of their generation assets.[51] Some states regulated this process heavily by dictating whether or not utilities could divest and structuring the divestiture to prevent future market abuse. For example, Texas required utilities that divested or transferred their generation assets to an affiliate company to auction off 15% of their generation assets to separate corporate entities and limited generation ownership to a maximum of 20% of the market.[52] Most states, however, imposed no such limitations on divestiture. While a few, like Connecticut, did not permit utilities to divest their nuclear generation initially, most adopted a laissez-faire approach,[53] – *i.e.* utilities could determine whether they divested, to whom they divested, and the amount they received in return for divestiture. For example, Maryland and Illinois let utilities decide whether to divest at all and to whom they divested – *e.g.*, to affiliated companies or non-affiliates. Illinois also let the market dictate the return utilities received for their generation.[54] When divesting to affiliated companies, utilities typically received either book value or only a small premium.

Divestiture methods varied by jurisdiction, with states generally splitting between two forms – an auction or a relatively unregulated transfer. The predominant method of divestiture was the auction approach in which the utilities auctioned off their generation to the highest bidders.[55] Affiliates were given no preference and the utility accepted the

---

50 Joskow Interim Assessment at 20.

51 Nancy Brockway, *Delaware's Electricity Future: Re-Regulation Options and Impacts* (May 2007) ("Delaware Study") at 40.

52 Synapse Energy Economics, Inc. *Electricity Restructuring Activities in the US: A Survey of Selected States* (Mar. 2002) (*available at* http://www.synapse-energy.com/Downloads/SynapseReport.2002-03.ACC.Electricity-Restructuring-Activities.02-08.pdf) ("Synapse Survey") at 55-56.

53 *See Status of State Electric Industry Restructuring Activity as of February 2003* (*available at* http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf) ("EIA Survey") at Connecticut; Synapse Survey at 15, 23.

54 *See* Exelon Corp., SEC Form 8-K (July 24, 2007) at 2.

55 *See* Synapse Survey, at 28; *See* Connecticut Dept. of Public Utility Control, Press Release, *DPUC Selects J.P. Morgan to Manage Auction of CL&P's Nonnuclear Generating Assets*, (Jan. 19, 1999) (*available at* http://www.dpuc.state.ct.us/electric.nsf/bb23886a033a7ef28525713c000031d4/caeda33f810fcd7e852568bf00517ca1?OpenDocument) ("DPUC Selects J.P. Morgan").

highest bid. Each state's public service commission and/or a third party oversaw these auctions to ensure that the auction process allowed bidders to compete on an equal basis.[56] Several New England states, New York, Pennsylvania, and California followed this approach. A few other states (including Maryland) allowed utilities to choose to whom to divest, with the state commission having oversight over the process. *See Mid-Atlantic Power Supply Ass'n v. Md. Pub. Serv. Comm'n*, 795 A.2d 160, 183 (Md. Ct. Spec. App. 2002) (interpreting Md. Code Ann. § 7-508(c)(2)).

2. Rate Reductions and Freezes

Following the divestiture of utilities' generation assets, most states imposed some form of rate freeze or rate caps that included a rate reduction.[57] States imposed these measures during the transition period to a competitive market in order to stabilize prices, while encouraging its consumers to switch suppliers. While the states did avoid price volatility, few consumers – particularly residential customers – switched suppliers. As market prices rose above the rate cap levels, merchant suppliers could not provide generation service for less, and customers had no reason to switch.

The lengths of the rate freezes varied, but were generally between three and five years,[58] although some states' rate freezes lasted the better part of a decade.[59] Rate reductions also varied but usually ranged from 5% to 20%.[60] States included these reductions because they assumed that once the competitive market materialized, competitive rates would remain lower than non-competitive ones. Like the rate freezes, the reductions would allow customers to begin choosing their suppliers. Rate reductions had almost universal appeal, and creating supposedly enduring rate reductions seemed desirable to most states. As we discuss below, however, rate reductions and freezes did not have their intended effect.

3. Consumer Choice

In every jurisdiction except Texas, consumer response to deregulation has been tepid. Switching can be broken down into two distinct customer types: large industrial customers and small commercial or residential customers. The former group has taken

---

56 *DPUC Selects J.P. Morgan.*

57 *See e.g.,* EIA Survey at California; *see also* Synapse Survey at 36 (describing Montana's decision to not impose a rate freeze, but rather to require the utility to provide default service at cost).

58 *See, e.g.,* MD. CODE ANN., PUB. UTIL. COS. § 7-505(d) (2007) (imposing four-year cap); EIA Survey at Michigan; Delaware Study at 14.

59 Delaware Study, Appendix II at 3-5 (discussing Illinois' ten-year rate cap); American Public Power Association, Massachusetts (May 2006) (*available at* http://www.appanet.org/files/pdfs/Massachusetts51006.pdf).

60 *See, e.g.*, American Public Power Association, Illinois (May 2006) (*available at* http://www.appanet.org/files/pdfs/Illinois051006.pdf) at 1; MD. CODE ANN., PUB. UTIL. COS. § 7-505(d); American Public Power Association, Massachusetts (May 2006) (*available at* http://www.appanet.org/files/pdfs/Massachusetts51006.pdf).

advantage of deregulation by switching suppliers.[61] For example, in Maine, 93% of large commercial customers have chosen non-utility suppliers.[62] Large customers have more incentive to switch because – due to their high usage levels – they can save money by switching, even if the difference in rates is small. These customers are generally more sophisticated and able to expend the resources needed to identify and evaluate alternate suppliers. Suppliers also can market to large commercial customers more effectively, and their transaction costs are generally lower.

On the other hand, in most states, few residential and small commercial customers have switched to alternate suppliers. For example, in Massachusetts, as of May 2008, only about 12.6% percent of residential costumers have switched suppliers, even though Massachusetts was one of the first states to introduce retail competition in 1998.[63] In Maine, fewer than one percent of residential and small commercial customers switched generators, even though competitive suppliers serve 93% of its large customers' load.[64] Other states experienced similarly low percentages despite encouraging the use of aggregators to spur customer switching.[65] The one exception is Texas, which embarked on an aggressive education and incentive-laden campaign to stimulate consumer switching. Texas' efforts included prohibitions on generator sales in an affiliate's service area until at least 40% of residential and small business customers had switched suppliers.[66] Most notably, however, Texas set its default service rates well above market prices, thus giving retail suppliers ample room to offer attractive, competitive prices.[67]

4. <u>Default or Standard Offer Services</u>

Every state that pursued deregulation offered a default or standard offer service option to customers that did not switch suppliers. States permitted utilities to procure

---

61 *See, e.g.,* Synapse Survey at 28.

62 *See* Maine Public Utilities Commission, *Current Migration Statistics* (Oct. 1, 2000) (*available at* http://www.maine.gov/mpuc/industries/electricity/electric%20restructuring/migrationrates.htm).

63 *See* Massachusetts Division of Energy Resources, *2007 Electric Power Customer Migration Data*, (Sept. 2007) (*available at* http://www.mass.gov/Eoca/docs/doer/2008migrate.pdf).

64 *See* Maine Public Utilities Commission, *Current Migration Statistics* (Sept. 1, 2008) (*available at* http://www.maine.gov/mpuc/industries/electricity/electric%20restructuring/migrationrates.htm); *see also* Synapse Survey at 33.

65 *See* National Energy Affordability and Accessibility Project: National Center for Appropriate Technology, *Illinois* (*available at* http://neaap.ncat.org/restructuring/il-re.htm) (discussing Illinois' use of aggregators); Synapse Survey at 25 (noting the lack of switching in the Illinois market); *see also* Mike Dennison, *Re-Regulation Bill Likely Headed to Governor*, The Montana Standard, (Apr. 19, 2007) (*available at* http://www.mtstandard.com/articles/2007/04/19/breaking_headline/hjjcjfiajchhhc.txt) (noting that competition never materialized in Montana).

66 Synapse Survey at 55.

67 *See* Consumer Strategist, *Manual on Choosing a Texas Electricity Company*, (Oct. 27, 2006) (*available at* http://www.electricity-texas.com/) (describing the default service rate as a "premium rate").

default services through two primary methods: a blind sealed-bid system and descending clock auctions. As discussed in more detail below, several states, including Maryland, use a price-based, blind Request For Proposal ("RFP") in which a utility submits bids for a specified block of full-requirements service, including capacity and ancillary services.[68] Utilities then evaluate and award these contracts based solely on price.

Other states, like New Jersey, use a descending clock auction. This auction allows suppliers to bid on the number of blocks they are willing to provide at a specified price.[69] So long as the suppliers bid more blocks than required, the price decreases.[70] When the number of blocks bid equals the number of blocks needed, the auction ends.[71] During the auction, suppliers can also set their exit price – *i.e.*, the lowest price at which they are willing supply power. Some states, like Illinois, plan to move from a descending clock auction to a sealed bid process. In order to address market power issues, some states have set upper limits on the amount of default service any single supplier can provide.[72]

5. <u>Consequences of Deregulation</u>

Deregulation has not fulfilled proponents' expectations. The most prominent shortcomings include (1) political and consumer resistance to significant price increases following expiration of price caps, (2) little or no retail competition for residential and small commercial customers, (3) possible market power and collusion concerns arising from the interaction between utilities and their affiliates, and (4) little to no new generation built.[73]

After deregulation had been in place for three to five years, states' rate freezes ended and, predictably, rates spiked dramatically to reflect current wholesale market prices. Political pressure mounted in every state to mitigate these new costs. Some states laddered in rate increases, but residential customers still experienced rate hikes of over

---

68 *See* Delmarva Power, *Delmarva Power Announces Results of Bidding for Delaware Standard Offer Services* (Feb. 2, 2006) (*available at* http://www.delmarva.com/*welcome*/news/releases/archives/2006/article.aspx?cid=644); MD. CODE ANN., PUB. UTIL. COS. § 7-510(c)(4)-(5).

69 *See* Proposal for Basic Generation Service Requirements to be Procured Effective June 1, 2008, *I/M/O Provision of Basic Generation Service For The Period Beginning June 1, 2008*, NJ BPU Docket No. ER07060379 (July 2007) at 23.

70 *Id.*

71 *Id.* at 23-24.

72 *See* Synapse Survey at 55-56 (imposing a ten percent cap on the market share of a single generator).

73 *See* Michael J. Trebilcock and Roy Hrab, *Electricity Restructuring: A Comparative Review* (Mar. 27, 2003) (updated March 2004) (*available at* http://www.law-lib.utoronto.ca/investing/reports/rp41.pdf) at 5; Delaware Study at 21.

50% after states lifted the freeze.[74] Some states experienced rate increases up to 100%.[75] Deregulation alone did not cause these rate increases, but it did exacerbate the uncertainty and instability that followed natural gas supply disruptions and electricity shortages in some transmission constrained areas. Multi-year price freezes coupled with market forces that drove prices up combined to produce significant rate shocks in many jurisdictions. Although all states have experienced increases in electric rates, the gap between average rates in restructured and regulated states has widened, with average rates in restructured states increasing more dramatically.[76]

As noted above, little competition developed for residential and small commercial customers. Small customers have little economic incentive to switch suppliers when default service reflects the market price.[77]

While policy makers had hoped that deregulation would spur construction of new, more efficient generation facilities, little construction has occurred. In fact, some current capacity market designs actively discourage needed investment because short-term market signals stimulate market participants to take advantage of and perpetuate constraints rather than eliminate them.[78] If new generation is built in a constrained zone to alleviate the constraint, the market price for capacity under a "demand curve" design – like the RPM in PJM – will drop in the newly constraint-relieved zone. The major problem with such capacity markets is that market participants have no "visible and financeable view" of what capacity prices will be when, if, and after their new generation comes on line.[79] Indeed, as one commentator noted, "there has been little new plant construction in any of the areas served by regional [competitive] wholesale markets" because generators "cannot recover the cost of new construction."[80] To alleviate this

---

74 *See Public Power & State Restructuring*, American Public Power Association, (*available at* http://www.appanet.org/aboutpublic/staterestructuringdetail.cfm?State=72&sn.ItemNumber=2102) (discussing 59% increase in Delaware SOS rates); *Facts About Illinois Rates*, Ameren, (July 2007) (*available at* http://www.ameren.com/MediaRoom/ADC_FactsAboutIllinoisRates.asp) (reporting on a 55% rate increase in Illinois).

75 Alexei Barrionuevo, *Rising Price of Electricity Sets Off New Debate on Regulation*, NY Times, (Feb. 17, 2007) (*available at* http://www.nytimes.com/2007/02/17/business/17utility.html) (discussing rate hikes of 130% to 200% in parts of Illinois).

76 Elise Caplan and Susan Kelly, *Time for a Day 1.5 Market: A Proposal to Reform RTO-Run Centralized Wholesale Electricity Markets*, 29 Energy Law Journal 491,523 (2008).

77 Delaware Study at 22-23.

78 Larry Kellerman, *Mending our Broken Capacity Markets*, Public Utilities Fortnightly (June 2006) at 58-62; *but see* Randall Speck and Miles Bidwell, *A New England Capacity Market That Works*, Public Utilities Fortnightly (Aug. 2006) at 19 (contrasting New England's Forward Capacity Market, which stabilizes the capacity payment at the cost of new entry).

79 *Id.*

80 Delaware Study at 21; *but see* Lawrence W. Reed, *Electricity Deregulation: Michigan Policy More Enlightened Than California's*, Mackinaw Center for Public Policy (Mar. 3, 2001) (*available at* http://www.mackinac.org/article.aspx?ID=3346) (describing new construction in Michigan); 2007 State of The Market Report, Vol. II at 136.

problem, some states have eased the path for generators and utilities to construct new generation.[81] For example, in 2001, California streamlined the siting process making it easier and faster, while providing incentives to generators to bring new generation online by a specified date.[82] Other states, like Illinois, lowered the standard utilities must satisfy in order to build new generation, requiring them to show only that they would be able to generate electricity cheaper than they could acquire it on the open market.[83]

Some states that allowed utilities to divest generation assets to affiliates or permitted utilities to purchase supply from affiliates, have raised inevitable questions about conflicting interests. Affiliates with substantial market power and a perceived opportunity for collusion become a logical target for inquiry when prices soar. *See* Complaint by the People of the State of Illinois, *Illinois v. Exelon Generation Co., LLC et al.*, FERC Docket No. EL07-47-000 (Mar. 15, 2007).

In light of these disappointing results from deregulation, several states – including Illinois, Connecticut, New Jersey, and Delaware – have evaluated various forms of re-regulation. These states, which have experienced many of the same deregulation disappointments as Maryland, have elected courses that they hope will produce cheaper, more reliable electricity. We will discuss these states and their re-regulation efforts below.

E. Maryland's Deregulation Experience

1. Divestiture and Transition to Competition

Maryland's Electric Customer Choice and Competition Act of 1999 initiated retail electric restructuring. MD. CODE. ANN., PUB. UTIL. COS. § 7-501, *et seq.* (Apr. 8, 1999) (the "1999 Md. Act"). The Act granted the Commission authority to oversee the deregulation process, and the Commission required the state's utilities to file restructuring plans, all of which it approved through settlement agreements.

For customers, the statute allowed all retail customers to choose their electricity supplier or receive default "standard offer" service. To mitigate price effects from the transition, the statute required utilities to provide residential customers with rate reductions and capped rates for commercial and industrial customers. On the supply side, the 1999 Md. Act opened the market to competition from new retail electricity suppliers and required traditionally integrated utilities to separate their generation assets from their transmission and distribution operations.

---

81 Delaware Study at 49; Press Release, *Governor Signs HB25* (May 17, 2007) (*available at* http://governor.mt.gov/news/pr.asp?ID=435).

82 *See* EIA Survey at California.

83 *See* Press Release, Illinois Energy Association, *Governor Signs Electric Rate Relief Bill* (Aug. 30, 2007) (*available at* http://www.ilenergyassn.org/library/publicdocs.asp?did=220); Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Sept. 25, 2007).

To facilitate competitive supply, the 1999 Md. Act required that by July 1, 2000, the utilities functionally, operationally, structurally, or legally separate their regulated and unregulated assets. *Id.* § 7-505(b)(10)(iii). The statute did not specify any particular mechanism for divestiture (*e.g.*, sale by auction to the highest competitive bidder), but it expressly permitted utilities to transfer their generation assets or facilities to affiliates.[84] *Id.* § 7-508(a). If a utility divested to an affiliate, however, the Commission had to approve a code of conduct that would control the relationship between the utility and any affiliate providing electricity supply and related services. *Id.* § 7-505(b)(10)(ii)(1). Utilities filed comprehensive restructuring plans, each of which the Commission finally resolved in settlements specifying how the utilities would divest generation assets and how they would transition to retail competition.

Baltimore Gas and Electric Company ("BGE") transferred its generation assets to its Constellation Energy affiliates at book value, *i.e.*, "the original cost less the related accumulated depreciation and accumulated deferred tax effects." Stipulation and Settlement Agreement, *In re BG&E Co.* (June 29, 1999) (8804/141) ("BGE Settlement Agreement") at ¶ 6. Delmarva Power and Light Company ("Delmarva") transferred its Crisfield generating assets at book value to an affiliate – Conectiv Delmarva Generation – and sold its Vienna plant to NRG, Inc.[85] Potomac Electric Power Company ("PEPCO") sold all its generation and related assets in an open and competitive auction that excluded company affiliates.[86] The auction resulted in $182.3 million to be paid to customers through a Competitive Transition Credit. *See* Application for Approval of Divestiture Sharing Plan, *In re Potomac Elec. Power Co.* (Apr. 26, 2001) (8796/269) at 3 and Ex. B. Potomac Edison Company ("Potomac Edison") transferred its generation assets at book value to its affiliate, AE Supply in 2000.[87]

The 1999 Md. Act permitted utilities to recover two types of "prudently incurred" and "verifiable" net transition costs (1999 Md. Act § 7-513(a),(b)) – (1) costs associated with the restructuring process and (2) stranded costs of generation assets that the utility would have traditionally recovered through rate-of-return regulation. *Id.* § 7-501(p)(1), (2). The Commission determined which transition costs would be allowed, set the recoverable value of transition costs each electric utility could collect (*id.* § 7-513(b)),

---

84 The 1999 Md. Act defined "affiliate" as a "person that directly or indirectly, or through one or more intermediaries, controls, is controlled by, or is under common control with, or has, directly or indirectly, any economic interest in another person." 1999 Md. Act § 7-501(b).

85 Public Service Commission of Maryland, *Electric Supply Adequacy Report of 2003* (Jan. 2003) ("2003 Adequacy Report") at 4.

86 Agreement of Stipulation and Settlement, *In re Potomac Elec. Power Co.* (8796/69) (Feb. 3, 1999) ("Phase I Settlement"), § 1.02; Order 75850, *In re Potomac Elec. Power Co.*, 90 MD PSC 329, 338 (8796/189) (Dec. 22, 1999). An amendment to the Phase I Settlement exempted two PEPCO generating stations, Benning Road and Buzzard Point, located in Washington, D.C., and barred the company from later claiming transition costs associated with these facilities. *See* Letter Order, *In re Potomac Elec. Power Co.* (Nov. 22, 2000) (8796/260). These facilities were later transferred at book value to a PEPCO affiliate.

87 Allegheny Energy, Inc., SEC Form 10-K For the Fiscal Year Ended December 31, 2001, at 22.

and designated recovery periods of different lengths and for different types of transition costs (*id*. § 7-513(a)(3)(ii)). Utilities recovered transition costs through Competitive Transition Charges ("CTCs") that appeared as line items on customers' bills. *Id.* at §§ 7-501(d), 7-513.

Delmarva identified $69 million of Maryland-related transition costs (including stranded and restructuring costs), but agreed in settlement to recover only $8 million, all from nonresidential customers. Order 75680, *In re Delmarva*, 90 Md. PSC 115, 122 (8795/98) (Oct. 8, 1999) ("Delmarva Settlement Agreement"). Because PEPCO's generation asset sales produced stranded benefits, PEPCO's customers did not pay stranded costs. Potomac Edison agreed to collect no stranded costs. Order 76009, *In re Potomac Edison Co.*, 91 Md. PSC 106, 120 (8797/129) (Mar. 15, 2000). Only the BGE settlement included collection of substantial transition costs[88] – $528 million (after-tax) – from Maryland's retail electric customers. BGE Settlement Agreement, ¶ 2.

On the demand side, the statute required that commercial and industrial customers be able to choose competitive suppliers by January 1, 2001. 1999 Md. Act § 7-510(a)(1)(ii). The choice program for residential customers could begin no later than July 1, 2000, and had to be implemented for all of the utilities' customers by July 1, 2002.[89] *Id*. § 7-510(a)(1). BGE, Delmarva, PEPCO, and Potomac Edison all made customer choice available to all customers beginning on July 1, 2000.[90] BGE Settlement Agreement at ¶ 9; Delmarva Settlement Agreement at § II.A.1-2; Order 75850, 90 MD PSC at 361; Potomac Edison Settlement Agreement at ¶¶ 14, 28.

To help ensure a smooth transition into deregulation and to prevent price volatility as the competitive electric market developed, the 1999 Md. Act capped commercial and industrial rates for four years at the price in effect the day before implementation of customer choice in each utility's distribution area. 1999 Md. Act § 7-505(d)(1). Furthermore, the utilities had to reduce residential customers' June 30, 1999 base rates by between 3% and 7.5% for four years. *Id.* at § 7-505(d)(4)(i)(1)-(2).

BGE froze its residential rates for six years, Delmarva and PEPCO froze their rates for four years, and Potomac Edison froze rates for commercial consumers for four years and residential consumers for eight years. BGE Settlement Agreement at ¶¶ 24, 25; Delmarva Settlement Agreement at § II.A.1-2; Order 75850, 90 MD PSC at 368; Potomac Edison Settlement Agreement, ¶¶ 18, 19-21. BGE reduced residential rates by 6.5%. BGE Settlement at ¶¶ 24, 25. Delmarva reduced its customers' rates by 7.5%. Delmarva Settlement Agreement at § II.A.1-2. Potomac Edison reduced rates effective

---

88 The settlement's transition costs include both stranded costs and out-of-pocket costs that BGE incurred as part of the restructuring process. BGE earlier estimated its restructuring costs at $85 million.

89 The statutory schedules could be adjusted upon a showing of good cause. *Id.* § 7-505(b).

90 Potomac Edison did not make customer choice available to its customers with certain individual contracts. Settlement Agreement, *In re Potomac Edison Co.*, (8797/86) (Sept. 23, 1999) ("Potomac Edison Settlement Agreement") at ¶¶ 14, 28.

December 31, 2001, by 7%. Potomac Edison Settlement Agreement at ¶¶ 15, 22. PEPCO reduced residential rates by about 7%. 90 MD PSC at 329.

2. Results of Deregulation

The 1999 Md. Act required utilities to procure wholesale electricity for those customers who had not switched to competitive suppliers. The utilities procured this necessary power through RFPs and Commission-approved procurement proposals. *See* Order 78400, *In re Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service*, Case No. 8908, Order 78400 (Apr. 29, 2003) (8908/184) and Order 78710 *In re Commission's Inquiry into the Competitive Selection of Electricity Supplier/Standard Offer Service*, Case No. 8908, Order 78710 (Sep. 30, 2003) (8908/269) (collectively the "Settlement Orders").

The RFPs seek full requirements contracts that include capacity, energy, ancillary services, renewable energy, congestion charges, and losses and "follow" load. *See* Order 78710 at 4. In other words, a supplier is responsible to provide a proportion of the utility's load at any time, not a specified amount of power. The RFPs seek supply by customer class, and the length of the contracts has varied in different auction years and for different customer classes.

Potential suppliers bid on "blocks" of power, which typically correspond to about 50 MW of supply. *See* Order 78710 at 5. The utility seeking the bids then converts the bids to a single present value of the projected cost stream according to a pre-determined formula. The utility calculates an average price and ranks the bids on the basis of this number. To protect against systemic problems that could cause above-market results, the Settlement Orders approved the use of a Price Anomaly Threshold ("PAT"). The PAT attempts to define the "highest reasonable wholesale market prices for full service SOS according to current market conditions." Order 78710 at 23. If the average price exceeds the PAT, the utility must remove the highest-priced award from the portfolio of winning bids and recalculate the average price. The utility repeats this process until the average price is less than or equal to the PAT.

As the rate freezes expired, Maryland's residential customers' rates increased by 35% to 72% for the 2005-2006 procurement period.[91] Increased natural gas prices following hurricanes Rita and Katrina, increased demand and continuing transmission constraints were the primary causes of these price increases. BGE's customers were hit the hardest by these price increases because it was procuring 100% of its residential load, while Delmarva and PEPCO were procuring only about 50% of their residential loads.

[91] Public 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* (Dec. 2006) ("Report to the Governor") at 4.

The Commission considered these price increases as typical of those experienced by other states in the region.[92]

Although restructuring was expected to stimulate construction of new power plants, merchant suppliers have built very few plants in Maryland. Since 2000, suppliers have built only about 700 MW of new capacity, 97% of which has been fueled by natural gas.[93] Furthermore, although Maryland has approved construction of an additional 3,292 MW of new capacity, only one of the projects – Constellation's 1,640 MW nuclear unit – is a base load plant, and activity on projects making up 780 MW of that new capacity has been suspended.[94] Although PJM has 6,393.1 MW of capacity in its interconnection queue that is not already in service, construction of 648 MW of that capacity has been suspended, and only 19.8 MW of that capacity are expected to be in-service by year-end 2008, with an additional 152.5 MW of that capacity expected to be in-service by year-end 2009.[95] The Commission described the outlook for the adequacy of Maryland's electricity supply in January 2007, as "fragile," with the small amount of new generation likely to be built adding to the uncertain outlook.[96]

The lack of new generation is particularly problematic because of the age of Maryland's existing generation plants. Sixty-seven percent of Maryland's total generating capacity is over 31 years old.[97] Almost 11% of plants are from 21 to 30 years old, with only 13.9% of plants between eleven and 20 years old and about 8.2% of plants between one and ten years old.[98] The old plants are less efficient than new plants and more likely to be affected by new, more stringent environmental requirements.

The lack of new generation also exacerbates Maryland's transmission constraints and the resulting congestion, which increases congestion charges. In 2006, LMPs east of Frederick County were \$9.43 higher than LMPs to the west of Frederick. Three years earlier, the gap was only \$2.90.[99] This situation could worsen. PJM projects that without

---

92 *Id.* at 4.

93 Public Service Commission of Maryland, *Ten-Year Plan (2006-2015) of Electric Companies in Maryland* (Dec. 2006) (" 2006 Ten Year Plan") at 28; Public Service Commission of Maryland, *Ten-Year Plan (2006-2015) of Electric Companies in Maryland* (Dec. 2007) ("2007 Ten Year Plan") ("There has been little change in the amount (in MW) and fuel-mix of generation in Maryland during the last decade").

94 2007 Ten Year Plan at 9.

95 PJM Generation Queue (*available at* https://www.pjm.com/planning/project-queues/queue-gen-active.jsp).

96 Public Service Commission of Maryland, *Electric Supply Adequacy Report of 2007* (Jan. 2007) ("2007 Adequacy Report") at 52.

97 2007 Ten Year Plan at 7.

98 *Id.*

99 2007 Adequacy Report at 3. Our Interim Report for Tasks 4 and 5 includes a more detailed analysis of LMP congestion charges.

the timely completion of the TrAIL transmission line, reserve margins in central Maryland will be barely adequate to ensure reliability by 2011.[100]

The PJM Base Residual Auction results confirm the worsening conditions for generation capacity in Maryland. Rather than attracting new generation through higher capacity prices, the SWMAAC capacity zone that includes Maryland saw a decline in the amount of available capacity and an increase in the price for capacity. For the 2009/2010 capacity supply period, SWMAAC saw "a net decrease in capacity of 122.7 MW due to derations and a net decrease in capacity cleared due to avoidable cost increases related to emission control system installations. The net impact was a reduction in capacity available to clear in the auction which caused a rise in the clearing price of $27.22/MW-day."[101] Rather than the declining capacity prices that had been predicted and that had been experienced in other parts of PJM, Maryland's capacity prices have increased with no assurance that those higher prices will do anything to stimulate new generation or demand response. As the Commission recognized recently, the Mid-Atlantic portion of the PJM region faces a 2,600-3,000 MW shortfall for the 2011/2012 capacity supply period – 600-690 MW of which are attributable to Maryland – and "the market structures designed to incent new generation in the constrained portions of the State have not yielded *any* new generation that could narrow or close the 2011-12 gap."[102]

Despite higher retail prices, Maryland's customers have not switched from default service to competitive suppliers. As of September 2008, only 3% of residential customers and 22.9% of commercial and industrial customers purchased power from competitive suppliers.[103] One year earlier, in September 2007, 2.6% of residential customers and 27.2% of commercial and industrial customers purchased power from competitive suppliers.[104] Although the number of residential customers purchasing

---

100 *Id.*; *see also* Order, *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, (Nov. 6, 2008) ("Gap RFP Order") at 1 ("PJM's fundamental message [in May 2008] was the same: unless significant new transmission projects are in service, the known resources committed for delivery in 2011-12 leave a regional, peak demand shortfall that we cannot ignore").

101 PJM, *2009/2010 RPM Base Residual Auction Results* (Oct. 17, 2007) (*available at* http://www.pjm.com/markets/rpm/downloads/2009-2010-base-residual-auction-results.pdf). Data on the amount of capacity in SWMAAC for the more recent 2010/2011 or 2011/2012 Base Residual Auctions is not available because SWMAAC did not clear as a separate locational delivery area in those auctions. *See* PJM 2010/2011 RPM Base Residual Auction Results (Feb. 1, 2008) (*available at* http://www.pjm.com/markets/rpm/downloads/20080201-2010-2011-bra-report.pdf); PJM 2011/2012 RPM Base Residual Auction Results (May 15, 2008) (*available at* http://www.pjm.com/markets/rpm/downloads/20080515-2011-2012-bra-report.pdf).

102 Gap RFP Order at 3, 5 (emphasis in original).

103 Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report All Investors Owned Utilities in Maryland Month Ending September 2008* (*available at* http://webapp.psc.state.md.us/intranet/ElectricInfo/enrollmentrpt_new.cfm).

104 Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report All Investors Owned Utilities in Maryland Month Ending September 2007*.

power from competitive suppliers has increased marginally, it remains low, while the number of commercial and industrial customers choosing competitive suppliers has decreased.

Few customers may be motivated to move to competitive suppliers so long as the SOS price undercuts the prices that competitive suppliers can offer. The Maryland Office of People's Counsel ("Md. OPC") reported price information for electricity suppliers, comparing the price for Standard Offer Service with the competitive residential prices being offered in the same service territory for November 2008.[105] In every case, the SOS price was significantly lower than any other competitor's price.[106] Moreover, relatively few competitive suppliers have entered the market. As of November 2008, the Md. OPC counted only seven suppliers offering residential service.[107]

III. Detailed Analysis of Particular States' Experiences With Deregulation

A. Connecticut

Connecticut, like Maryland, is capacity constrained and is part of an RTO, ISO New England ("ISO-NE"). Recognizing that deregulation did not bring the expected benefits, Connecticut took steps to re-assert control over its electric supply through legislation, rulemaking, and participating actively in litigation that shaped ISO-NE's wholesale markets.

1. Summary of Deregulation Framework

Connecticut's Governor signed Public Act 98-28 in April 1998, providing for retail choice beginning in January 2000, with all customers permitted to choose competitive suppliers by July 1, 2000. The legislation capped default service rates at their December 31, 1996, level through December 31, 1999. An Act Concerning Electric Restructuring, Conn. Pub. Acts 98-28 at § 3(b) (1998) ("1998 CT Act"). Between January 1, 2000, and December 31, 2003, the legislation capped default service rates at ten percent below the base rates in effect on December 31, 1996. *Id.* at § 20(a)(2).

The 1998 CT Act required Connecticut's utilities – The Connecticut Light & Power Company ("CL&P") and The United Illuminating Company ("UI") – either to divest or functionally separate their non-nuclear generation assets no later than January 1, 2000, and their nuclear generation assets by January 2004. *Id.* at §§ 5(a), 7(b). The utilities could only recover stranded costs if they divested their plants. *Id.* at §§ 5(a)(2),

---

105 Maryland Office of People's Counsel, *Electricity Suppliers – Price Comparison Information* (June 4, 2007) (*available at* http://www.opc.state.md.us/assets/documents//PriceComparisonInformation 061807.pdf and http://www.opc.state.md.us/assets/documents//Electric Supplier Prices November 2008.pdf).

106 *Id.*

107 *Id.*

7(b). UI and CL&P had to use any proceeds above the total book value of their divested assets to offset stranded costs. *Id.* at § 6(b)(6).

UI sold its generating assets through a competitive bidding process. *DPUC Review of the United Illuminating Company's Divestiture Plan Phase I – Sale of Non-Nuclear Generating Plants*, CT DPUC Docket No. 98-10-07 (Mar. 5, 1999) at 1. CL&P sold some of its generating assets through an auction and transferred the remainder to an affiliate.[108]

The legislation further required UI and CL&P to provide default service to those customers who did not purchase electricity from competitive suppliers. *DPUC Monitoring The State Of Competition In The Electric Industry*, CT DPUC Docket No. 05-11-05 (Feb. 22, 2006) ("2006 CT DPUC Monitoring Report") at 6. Between January 2000, and December 2003, default service was called Standard Offer ("SO"). *See id.* at 5-7, 11. The Connecticut Department of Public Utility Control ("CT DPUC") established the energy portion of the rates based on each utility's cost to acquire SO generation, plus a "retail adder." *Id.* at 5. The retail adder represented the additional costs competitive suppliers would incur to provide electric generation service to each class of customers and was imposed on SO rates to enable suppliers to compete with SO generation. *Id.* at 5, 19. The CT DPUC set these rates at a level that it expected would attract competitive suppliers to the market. *Id.* at 5. CL&P obtained its SO supply through a request for proposal process.[109] It fulfilled 50% of its requirements through a contract with an affiliated company, Select Energy, and the other 50% through contracts with two unaffiliated companies.[110] UI entered a contract with Enron Capital & Trade Resource Corp. to fulfill all its SO needs.[111]

As the end of the SO period approached, the state adopted An Act Concerning Revisions to the Electric Restructuring Legislation, establishing Transitional Standard Offer ("TSO") rates for those customers who did not purchase competitive retail supplies. Conn. Pub. Acts 03-135 at § 4(b)(2). The TSO, excluding any "federally mandated congested charges," could not exceed UI's and CL&P's base rates in effect on December 31, 1996. *Id.* at § 4(b)(2)(B). The TSO rates did not, however, include retail adders above the price offered by the wholesale suppliers. 2006 CT DPUC Monitoring Report at 5. CL&P purchased all of its 2004 TSO requirements at the start of the period, but only portions of its 2005 and 2006 requirements, purchasing additional requirements in 2004, and the remainder in November 2005. *Id.* at 13. UI, on the other hand, purchased all of its TSO requirements for the entire three-year period at the same time. *Id.* at 5, 13.

---

108 Connecticut Light & Power Company, Annual Report (SEC Form 10-K For the Fiscal Year ended December 31, 2000 ("CL&P 2000 10-K") at "Connecticut Rates & Restructuring."

109 CL&P 2000 10-K at "Connecticut Rates & Restructuring."

110 *Id.*

111 The United Illuminating Company, Annual Report (SEC Form 10-K) For the Fiscal Year ended December 31, 2000 ("UI 2000 10-K").

Connecticut again extended default service as the end of the TSO period approached, enacting Public Act 05-01, An Act Concerning Energy Independence (2005). That statute required UI and CL&P to provide Standard Service ("SS") and Supplier Of Last Resort Service ("LRS") to consumers who did not purchase electricity from competitive suppliers. CL&P and UI must provide SS to electric customers (1) whose maximum electric demand is less than 500 kilowatts or who do not use a demand meter, and (2) who do not arrange for or are not receiving service from a competitive electric supplier. *DPUC Monitoring the State of Competition in the Electric Industry*, CT DPUC Docket No. 06-10-22 (Jan. 17, 2007) ("2007 CT DPUC Monitoring Report") at 5. The legislature required that CL&P and UI procure SS contracts through a plan that requires a portfolio of service contracts for terms of not less than six months, procured in an overlapping pattern, in a manner that encourages competition. Contracts for shorter terms may be procured to ensure the lowest retail prices, reliable service, and prudent portfolio management. *Development and Review of Standard Service and Supplier of Last Resort Service – Phase I*, CT DPUC Docket No. 06-01-08PH01 (June 21, 2006) ("CT DPUC SS/LRS Order") at 1.

The CT DPUC approved the general structure of the SS and LRS auctions, but allowed CL&P and UI to define the specific procedures to be used. *See generally* CT DPUC SS/LRS Order. The CT DPUC specifically forbade CL&P and UI, however, from using a descending clock auction for SS and LRS auctions, finding no concrete evidence that a descending clock auction actually leads to more favorable results or lower prices. *Id.* at 5. The CT DPUC also directed the utilities to stagger their solicitations so that they did not seek bids at the same time. *Id.* at 14. The CT DPUC feared that simultaneous solicitations could limit the number of available bidders, resulting in higher prices. *Id.* The CT DPUC also required the utilities to seek full requirements contracts for both SS and LRS. *Id.* at 12-13.

In the CT DPUC SS/LRS Order, the CT DPUC gave the utilities broad flexibility in structuring their respective SS procurement plans. Each utility has divided its SS load into a number of equally sized "slice-of-system" tranches for full requirements service. CL&P's contract terms have varied in length from three to twelve months, and UI contract terms have varied from six to twelve months. Each utility conducts periodic procurements that are scheduled to diversify the timing and term of the contracts in the laddered SS portfolio with the goal of stabilizing SS retail rates.

CL&P and UI must provide LRS to those customers (1) whose maximum electric demand is greater than 500 kilowatts and (2) who are not on special contracts or flexible tariffs. 2007 CT DPUC Monitoring Report at 10. LRS must reflect monthly wholesale price variations, so utilities procure LRS contracts through a bidding process that obtains all the necessary supply requirements (with no portfolio of laddered contracts). *Id.*; CT DPUC SS/SOLR Order at 17-18. In 2007, utilities procured LRS in six-month, non-overlapping contracts. In accordance with Public Act 07-242, An Act Concerning Electricity and Energy Efficiency (2007) ("CEEE"), LRS terms will be reduced to three months beginning in January 2008.

2. Factors Driving Connecticut to Modify The Deregulated Framework

Connecticut anticipated that retail competition would lower rates, shift generation risks from ratepayers to third parties, and stimulate new services and technologies. 2006 CT DPUC Monitoring Report at 26. As of February 2006, all of those goals had not materialized, causing Connecticut to re-evaluate its deregulation framework. *Id.* As with other states that deregulated their electric markets, competitive retail suppliers primarily focused on large industrial customers. New merchant generation in Connecticut constructed since 2000 consists solely of three 49 MW gas turbines (Wallingford units, under cost-of-service Reliability Must Run ("RMR") agreements until they could participate in the Locational Forward Reserve Market ("LFRM") in June 2007) and 575 MW of combined cycle units (Milford Power, also under RMRs until full implementation of the Forward Capacity Market ("FCM") in 2010).[112] As of September 2006, only one and a half percent of combined CL&P and UI customers received electric service from competitive suppliers. 2007 CT DPUC Monitoring Report at 5. Five competitive suppliers serviced those customers. *Id.* at 6. Average competitive rates for commercial, industrial, and streetlighting customers were lower than CL&P's default rates by approximately three percent, 29% and twelve percent respectively. *Id.* at 9 and Table 6. Competitive residential rates, however, were approximately two percent higher than CL&P's residential rates. *Id.*

In February 2006, the CT DPUC concluded that "[e]ven with the significant increase to CL&P's transitional standard offer generation rates in January 2006, to date there has been ***insignificant response by suppliers***." 2006 CT DPUC Monitoring Report at 11 (emphasis added). Because UI entered a favorable TSO contract that kept those rates low, there was "***virtually no competitive supply***" in its territory. *Id.* (emphasis added). Indeed, although the CT Siting Council has approved 3548 MW of new capacity since July 1, 1998 (the effective date of the 1998 CT Act) only 1586 MW of new capacity is operational.[113] At the same time, growing demand caused Connecticut's reserve margins to decline, requiring additional resources to meet system demand by no later than 2010. *Id.* at 12-13. Without some state action, the CT DPUC expected Connecticut's capacity deficit to reach 670 MW in 2009, "further exacerbat[ing] volatile market price sensitivity for end-use customers regionally and specifically in Connecticut." *Id.* at 13

Furthermore, Southwest Connecticut ("SWCT") – which accounts for 50% of Connecticut's total system demand – relies extensively on old, inefficient generation. *Id.* at 13, 17. Because SWCT is transmission constrained, it is difficult to import electricity

---

112 RMR is a FERC-approved payment mechanism that permits generators that are needed for reliability purposes to be paid their operational costs, in return for being available at peak load times. Generators must apply to FERC for approval to collect RMR payments. Under the FCM, ISO-NE purchases sufficient capacity for reliable system operation for a future year at competitive prices through a descending clock auction. The FCM is designed to ensure adequate reserve margins and to stimulate investment in new resources – including DSM – where it is needed most.

113 Connecticut Siting Council Website, Generation Facility Status (*available at* http://www.ct.gov/csc/cwp/view.asp?a=949&Q=247872&cscNav=)

generated in another area into SWCT. *Id.* at 17. Flaws in the wholesale market structure discouraged generators seeking to invest in new power plants where they are needed most. *Id.* at 13. Further exacerbating the problem, Connecticut must pay above-market rates for RMR contracts to compensate SWCT's old, inefficient plants at cost-of-service rates. *Id.* at 17-18. The CT DPUC believes that FERC awards RMR contracts too readily and that the contracts raise Connecticut's electric rates, while providing little incentive for generators to operate efficiently. *Id.* at 24. The CT DPUC concluded that "[a] final resolution to the dilemma of creating financial incentives to promote system capacity should improve the investment climate and lead to greater investments in reliability in the future." *Id.* at 13. At the same time, the CT DPUC recognized that new capacity charges will also increase customers' rates. *Id.*

The relatively low, stable SO and TSO prices also discouraged new suppliers from entering the market. Retail suppliers might have competed with the utilities' rates more easily if the utilities had procured contracts for shorter time periods and adjusted their rates more frequently – but may also have created higher, less stable retail prices. *Id.* at 13. The lack of new generation in load pockets aggravated congestion-related charges. *Id.* at 13-14.

The few new plants that suppliers built used natural gas, thereby exacerbating Connecticut's reliance on that expensive fuel and further increasing energy costs. New merchant generators built natural gas-fired plants almost exclusively, in part because of their low relative capital costs. As the cost of natural gas increased, these plants dictated the market clearing price at their marginal operating costs. *Id.* at 15. Indeed, natural gas plants represent the marginal bid over 90% of the time. *Id.* Although higher electric prices should theoretically encourage fuel diversity, this has not occurred in Connecticut. *Id.* at 15. Costs, siting, and environmental issues may have limited the introduction of non-gas resources. *Id.* at 16.

Connecticut also expected deregulation to stimulate construction of transmission upgrades. Although Connecticut sited transmission upgrades into and within SWCT that are expected to eliminate congestion in SWCT by 2010, it still needs to increase interconnections with neighboring states to ensure that it is able to import sufficient capacity. *Id.* at 18. Connecticut, like Maryland, cannot control siting or completion of those inter-state lines.

Similarly, retail competition did not stimulate innovative services. *Id.* Legislative mandates and non-market initiatives by the utilities and ISO-NE – not competition – provoked a greater emphasis on conservation, renewable energy, and demand response. *Id.* at 18.

Finally, retail competition did not develop. As of December 2005, only three generators provided competitive service, but by September 2006, only five generators provided competitive service within the state. 2007 CT DPUC Monitoring Report at 6; 2006 CT DPUC Monitoring Report at 8. Although recent higher default service prices have made competitive service more attractive, the CT DPUC continues to be concerned about the lack of wholesale competition. *See* 2006 CT DPUC Market Monitoring Report at 22-25. In part, wholesale competition has been hampered by uncertainty about the stability of markets. New England's FCM has yet to be fully implemented and "substantial" additional uncertainties remain about ISO-NE's markets for ancillary services. *Id.* at 25. Moreover, until new suppliers begin to build generation in SWCT, some existing generators will have substantial market power.

3. Steps Taken To Re-Regulate

In assessing what steps could be taken to stimulate more investment in new generation in Connecticut (including renewable resources) and more retail competition, the CT DPUC recognized that its goals sometimes conflict with decisions being made at the wholesale (federal) level. *Id.* While acknowledging that it had to address these conflicting goals, the CT DPUC admonished that "ISO-NE must also recognize and consider the rate impact of its proposals on end users. A great deal of time has been spent working on the wholesale market and more is needed on both the wholesale as well as retail side, including a concerted effort to align the two." *Id.*

Based on its concerns about the deregulated market and the recognition of the interplay of federal and state goals, Connecticut took numerous steps to re-regulate its electric market, including (1) requiring CL&P and UI to enter long-term, competitively awarded contracts to purchase in-state capacity, (2) requiring utilities to procure renewable generation resources, (3) participating actively in designing and influencing the FERC-regulated wholesale market, and (4) creating an Energy Advisory Board to plan and stimulate energy projects.

In an effort to manage federally mandated congestion charges ("FMCCs") – *e.g.*, LMPs and locational capacity charges that could continue to increase Connecticut's electric costs, Connecticut enacted Public Act No. 05-1, An Act Concerning Energy Independence ("EIA") (2005). The legislature adopted EIA "in response to: rising energy prices; the status of Connecticut's local generation capacity (much of which is relatively old, inefficient, and more polluting than new technologies); and a move by the ISO New England (ISO-NE) and the Federal Energy Regulatory Commission (FERC) to put in place locational capacity and reserve markets." Connecticut Department of Public Utility Control Request for Proposals To Reduce Impact of FMCCs, *DPUC Investigation of Measures To Reduce Federally Mandated Congestion Charges*, CT DPUC Docket No. 05-07-14PH02 (Sept. 13, 2006) ("CT DPUC RFP"), at 4. The EIA directed the CT DPUC to identify measures that could reduce FMCCs, including demand response programs, distributed resources, and capacity contracts between utilities and merchant generators. EIA §§ 12(a), (c). The statute further directed the CT DPUC to issue an RFP soliciting the development of long-term projects designed to reduce FMCCs and authorized utilities to enter contracts for renewable generation. *Id.* § 12(c). The EIA also authorized the CT DPUC to order CL&P and UI to take any measures it deemed appropriate for implementing those cost-reduction projects. *Id.* § 12(a).

In response to the EIA, the CT DPUC performed a "Needs Assessment" to determine the types of projects that should form the basis of the RFP process. *See* Report on the Electricity Sector Needs of Connecticut 2007-2021, *DPUC Investigation of Measures To Reduce Federally Mandated Congestion Charges*, CT DPUC Docket No. 05-07-14PH02 (Aug. 25, 2006, revised). The CT DPUC determined that three different ISO-NE product markets created potential FMCCs: energy, FCM, and LFRM. CT DPUC RFP at 12. ISO-NE's LFRM is intended to ensure that sufficient operating reserves are available where they are needed in constrained areas, *i.e.*, in both Connecticut generally and SWCT. To date, the LFRM auctions have cleared at the cap of $14/kW-month, indicating that there are insufficient operating reserves – *i.e.*, peakers – in Connecticut as a whole and in SWCT. The LFRM drives Connecticut's short-term needs for peaking units. *Id.* The FCM is designed to ensure adequate reserve margins and to stimulate investment in new resources – including DSM – where it is most needed. ISO-NE has determined, at least for the first FCM auction in February 2008, that there is no locational capacity requirement for Connecticut. The FCM dictates Connecticut's long-term needs and is driven by the level of peak demand relative to the amount of in-state installed capacity. *Id.* Finally, in the energy market – both day-ahead and real-time – Connecticut's LMPs tend to be higher than New England as a whole due to transmission congestion and existing generators with high marginal costs. *Id.*

With these considerations in mind, the Needs Assessment analyzed each product market separately under various scenarios of supply and demand. *Id.* at 12-13. The Needs Assessment then analyzed the incremental capacity requirements of the three markets on a joint basis. *Id.* at 13. Based on the Needs Assessment, the CT DPUC determined that Connecticut required 629 MW of incremental capacity in 2007, and SWCT required 158 MW in 2007, which declined to 58 MW in 2008. *Id.* at 14-15.

In responding to the utilities' RFPs, suppliers submitted separate bids for the FCM and LFRM markets and included an Annual Contract Price ("ACP"), which represented the total capacity payments the bidder required to develop and operate the project. *Id.* at 16. Under the contract's payment structure, if the ACP is higher than the Auction Clearing price in the Forward Capacity Auction for the applicable period, the Supplier pays the utility the difference. *Id.* Conversely, if the ACP is lower, the utility pays the supplier the difference. *Id.*

The final contracts also contain performance requirements related to annual Target Availability and thermal efficiency. *Id.* at 17. Failure to meet these requirements reduces monthly payments. *Id.* at 17-18. To further support the goals of the EIA, the CT DPUC required that bids represent incremental or new capacity, that projects be located in the state of Connecticut, and that output be deliverable electrically in Connecticut. *Id.* at 29.

The CT DPUC received 33 project qualification submissions from 20 different entities in response to the RFP and selected four winning projects in April 2007.[114] The

[114] Press Release, CT DPUC, *DPUC Receives 33 Qualification Submissions from 20 Bidders in Capacity RFP* (Nov. 2006) (*available at*

winning projects total 787 MW of new capacity and potentially reduce ratepayer costs by as estimated $1 billion.[115] The projects are: (1) a 620 MW gas-fired combined cycle base load plant, (2) a 66 MW oil-fired peaking facility located in SWCT, (3) a 96 MW gas-fired peaking facility also located in SWCT, and (4) a five megawatt state-wide energy efficiency project.[116] The winning bidders are all new suppliers in Connecticut, which should reduce market power for suppliers in the state.[117] The three generation projects re-use industrial sites, including previous electric power generation sites.[118] The CT DPUC, after a contested proceeding, approved CL&P's and UI's contracts for the winning projects' capacity.[119] CL&P and UI are also required to negotiate long-term contracts for the electric energy output from these facilities.[120] Those contracts will only be approved, however, if the CT DPUC determines that they will reduce and stabilize the cost of electricity to Connecticut ratepayers.[121]

In a separate proceeding, the CT DPUC also procured additional peaking generation capacity. The CEEE allowed any entity – and required CL&P and UI – to submit a plan between January 1, 2008, and February 1, 2008 to build peaking generation.[122] The peaking generation could not be cross-subsidized by the utilities' affiliates. The generation owner must bid the unit into all regional ISO-NE markets using cost-of-service principles and guidelines established by the CT DPUC, and will be compensated at its cost-of-service, plus a reasonable rate of return – *i.e.*, not based on market prices. The CT DPUC first held a proceeding to establish the process and criteria for procuring peaking generation.[123] As part of this proceeding, the CT DPUC performed a needs assessment to determine the amount of new peaking generation needed to satisfy

---

http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/9a50f9946b9390658525722900683361/$FILE/Press%20Release%20November%2017%202006_Revised.doc); Press Release, CT DPUC, *DPUC Announces 4 Winning Bids in Capacity RFP: Projects Represent 787 MW of New Electric Capacity for CT*, (Apr. 2007) (*available at* http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/0da262db6da4f243852572c6006a91b3/$FILE/4.23.07%2005-07-14PH02%20pressrelease.doc) ("CT DPUC April 2007 Press Release").

115 CT DPUC April 2007 Press Release. The methodology used to estimate reduced ratepayer costs has been disputed and may have significantly overstated the estimated benefits. *See, e.g.*, Brief of the Office of Consumer Counsel, *In re DPUC Review of Energy Independence Act Capacity Contracts*, CT DPUC Docket No. 07-04-24 (July 31, 2007).

116 *Id.*

117 *Id.*

118 *Id.*

119 *DPUC Review of Energy Independence Act Capacity Contracts*, CT DPUC Docket No. 07-04-24 (Aug. 22, 2007).

120 CEEE § 117(a).

121 *Id.*

122 CEEE § 50.

123 *DPUC Investigation of the Process and Criteria for Use in Implementing Section 50 of Public Act 07-242 – Peaking Generation*, CT DPUC Docket No. 07-08-24 (Dec. 14, 2007).

Locational Forward Reserve Requirements ("LFRR").[124] Based on the needs assessment, the CT DPUC determined that 290 MW of quick-start capacity would be needed to meet the LFRR and an additional 210 MW of "overhang" capacity should be procured to maximize the net benefits to Connecticut ratepayers, although the CT DPUC reserved the right to alter the portfolio size if a larger portfolio best served ratepayers interests.[125]

The CT DPUC evaluated the proposals based first on eight qualitative minimum threshold criteria, which were intended to be straightforward factors that could be assessed without extensive financial, commercial, or engineering analysis.[126] These criteria required the bidders to demonstrate (1) sufficient technical, managerial, and financial capability, (2) that there was no cross-subsidization by affiliated entities, (3) that the project met all requirements to participate in the ISO-NE LFRM auction, (4) that plan sponsors had legal entitlement to each site on which a project would be built, (5) that the facility could operate when called upon, (6) that the sponsors had plans for building the projects, (7) that the projects had a minimum investment grade credit rating, and (8) that they would adhere to the CT DPUC-approved contract. The CT DPUC then evaluated each project's costs and benefits to Connecticut ratepayers.[127] The CT DPUC and its Prosecutorial Unit ("PRO") requested cost and technical clarifications, and the PRO independently estimated costs for electric interconnection and gas interconnection and adjusted the project's estimate when it found a material difference. If two or more projects had costs – expressed in $/kW – within 5% of each other, the CT DPUC evaluated the projects based on nine qualitative factors: (1) early commercial operation date and low risk of project delays, (2) low risk of cost increases, (3) managerial, technical, and financial capabilities, (4) environmental benefits, (5) blackstart capability (ability to operate without relying on external energy sources), (6) Ten-Minute Non Spinning Reserves capability, (7) opportunity to purchase facility at end of contract, (8) furtherance of fuel diversity, and (9) located in SWCT.[128]

Because the CT DPUC does not regulate merchant generators, it required the bidders to agree to enter into a Contract for Differences with UI or CL&P.[129] The CT DPUC determined that such a contract avoids conflict with FERC jurisdiction because the electric distribution company does not actually purchase output. Rather, the merchant generator simply agrees to participate and offer products into wholesale markets for a specified price. The payment structure is based on the Monthly Contract Price ("MCP") – calculated through a formula set by the CT DPUC, based on fixed and variable costs – and the Monthly Market Revenue ("MMR") – also calculated through a formula set by

---

124 *Id.* at 12-23.

125 *Id.* at 21.

126 *DPUC Review of Peaking Generation Projects*, CT DPUC Docket No. 08-01-01 (June 25, 2008) ("Review of Peaking Generation") at 11-13.

127 *Id.* at 13-14.

128 *Id.* at 15.

129 *Id.* at 51.

the CT DPUC.[130] If the MCP exceeds the MMR, the buyer pays the supplier the difference. Conversely, if the MMR exceeds the MCP, the supplier pays the buyer the difference.

Seven entities submitted proposals for twelve projects based on these criteria.[131] The CT DPUC determined that ratepayers were best served by a portfolio of 520 MW of summer peaking capacity comprised of two projects.[132] The selected portfolio is expected to provide a net present value benefit to ratepayers of $864 million over the life of the contracts.[133]

In another key component of its re-regulation strategy, Connecticut, through the CT DPUC, sought to design and influence the FERC-regulated wholesale market. Since 2000, the CT DPUC has intervened and participated actively in almost 100 proceedings at FERC related to wholesale markets. Most notably, the CT DPUC led the New England states' efforts to shape the wholesale capacity market, providing counsel and experts who developed the current FCM structure that is more advantageous for Connecticut than ISO-NE's previous proposals. The CT DPUC has also pursued appeals of FERC orders that did not accommodate Connecticut's interests.

Finally, Connecticut created an Energy Advisory Board ("CEAB") to plan and stimulate energy projects. An Act Concerning Long-Term Planning For Energy Facilities, Conn. P.A. 03-140 at § 16. The CEAB prepares annual reports, represents Connecticut in regional energy system planning processes, issues requests for proposal for alternative solutions when a generator seeks to build a new plant, and participates in forecast and life-cycle proceedings. *Id.* at § 16(b). The yearly reports outline the "initiatives that will be key to achieving the state's long-term visionary goals and that will help the state to create a successful energy policy."[134] Among other things, the report (1) assesses current energy supplies, demand, and costs, (2) identifies and evaluates factors likely to affect future energy supplies, demand, and costs, (3) identifies progress made toward achieving long-term goals, (4) recommends ways for decreasing dependence on fossil fuels, (5) assesses the state's gas and electric system infrastructure, (6) evaluates the impact of regional transmission infrastructure planning on the state's interests, (7) considers alternative energy planning mechanisms, (8) defines energy policies and long-range energy planning objectives, and (9) recommends administrative and legislative actions to implement these policies. *Id.* at § 17. This report is similar to the integrated resources plans ("IRPs") utilities prepared under regulatory supervision

---

130 *Id.* at Attachment 1 (Peaking Generation Cost of Service Contract for Differences) at Article 6.

131 *Id.* at 4.

132 *Id.* at 1; PRO Exhibit LFE-68b, *DPUC Review of Peaking Generation Projects*, CT DPUC Docket No. 08-01-01 (May 19, 2008) ("PRO Exhibit LFE-68b") at 1. The initially selected BE II project was removed at the last minute and replaced with an option proposed by GenConn.

133 PRO Exhibit LFE-68b at 1.

134 Connecticut Energy Advisory Board, *2007 Energy Plan for Connecticut* (Feb. 6, 2007) at 1; *see* Conn. P.A. 03-140 at § 17.

prior to deregulation. Those IRPs were more detailed, but also analyzed current energy usage and capacity, expected energy usage, and planned transmission and generation upgrades. *See* Conn. Gen. Stat. § 16-50r.

To help develop the plan, CL&P and UI must file with the CEAB yearly proposals for meeting demand – *i.e.*, effectively an IRP. CEE §§ 51, 52, 117. If more generation is needed, the CT DPUC will issue an RFP, and CL&P and UI must enter contracts with the selected bidders. *Id.* § 52(b). After June 30, 2009, if the CT DPUC does not approve any proposals, CL&P and UI may submit their own proposals. *Id.* § 117(a). CL&P and UI submitted their first such plans on January 1, 2008, and the CEAB issued its report on August 1, 2008.[135] The CEAB, in the 2008 Comprehensive Plan, recommended that (1) the CT DPUC focus on Demand Side Management and renewable energy and (2) consider whether bilateral contracting will help meet renewable energy, price stability, and cost reduction objectives. The CEAB determined that because of the procurement of 700 megawatts of peaking generation, Connecticut does not need currently to procure additional capacity.[136]

4. <u>Additional Mechanisms</u>

Although the legislature has not adopted it, and it has received only mixed support, the Connecticut Attorney General has also proposed creation of a Connecticut Electric Authority.[137] The proposed Authority would (1) issue low-cost bonds for the purchase or construction of new power plants, (2) assist in financing new, privately owned power plants or buy existing private generators, (3) act to block imposition of FMCCs, (4) purchase all power from generators in open public auctions and sell it to CL&P and UI at cost, (5) buy power in small- or mid-sized increments when the price is low, and (6) administer the state's conservation and load management fund.[138] The Attorney General also proposed a windfall profits tax to be set by the legislature and to apply to earnings above a certain level.[139] He suggested setting the tax at 25-to-50 percent on profits greater than 20%.[140] The Connecticut General Assembly considered, but did not vote on, a bill that included an alternative to the Connecticut Electric Authority, called the Connecticut Energy Authority ("CEA"). *See* Substitute Bill No. 5819, An Act Concerning Energy Relief and Assistance, State of Connecticut General Assembly, February Session, 2008 ("Substitute Bill No. 5819"). The CEA would (1)

---

135 *See* Connecticut Energy Advisory Board, *2008 Comprehensive Plan for the Procurement of Eenrgy Resources* (Aug. 1, 2008) ("2008 Comprehensive Plan") at 2.

136 *Id.* at 13-14.

137 Press Release, Connecticut Attorney General's Office, *Attorney General Unveils Sweeping Proposals To Lower Electricity Costs; Calls For Windfall Profits Tax, State Authority To Buy Power, Build, Operate Power Plants*, (Feb. 21, 2006) (*available at* http://ct.gov/AG/cwp/view.asp?A=2426&Q=310272).

138 *Id.*

139 *Id.*

140 *Id.*

procure least-cost supply-side and demand-side resources through competitive procurement processes, (b) construct and operate generation facilities, and (c) sell electricity at cost to distribution companies and municipal electric utilities and cooperatives. *Id.* at § 1(b). The CEA was expected to issue a request for proposals to procure long-term electricity contracts for Connecticut citizens by January 1, 2009. After procuring the power, the CEA would have been able to transfer title to the power to the electric distribution companies. *Id.* at § 2. The costs of administering the contracts would have been charged to ratepayers on nonbypassable charges. *Id.*

Substitute Bill No. 5819 also included provisions intended to mitigate variations in standard service prices to consumers. *Id.* at § 6. First, the CT DPUC, in consultation with the CT Office of Consumer Counsel and after a contested proceeding, would establish principles and standards to govern the manner in which electric distribution companies enter into bilateral contracts to provide standard service supply. *Id.* at § 6(c)(3). Second, the CT DPUC, would establish a standard service procurement plan specifying how electric distribution companies could purchase power for standard service (*e.g.*, procuring load through full-requirements bilateral contracts, procuring individual electric supply components – base load, intermediate and peaking, capacity – through RFPs and bilateral contracts, procuring physical and financial hedges). *Id.* at § 6(c)(5). An outside consultant hired by the CT DPUC would then oversee the electric distribution companies' procurement of standard service supply, and the CT DPUC would approve any contracts entered into pursuant to the plan. *Id.* at § 6(c)(6)-(8). Third, the CT DPUC would conduct a contested case at least biennially to determine the efficacy of the process of procuring power. *Id.* at § 6(c)(9).

Substitute Bill 5819 would also have directed the CT DPUC to develop and issue requests for proposals to address any deficiencies or needs identified by the CEAB. *Id.* at § 7. The CT DPUC could only approve responses to requests for proposals for which expected benefits exceeded expected costs and which were in the best long-term interest of Connecticut ratepayers. Successful responses would only recover rates based on their cost of service. This is largely the procedure the CT DPUC followed in approving peaking generation proposals, described previously.

B. Delaware

Delaware's in-state generation capacity is insufficient to meet its demand requirements, and it imports most of its generation from West Virginia and Pennsylvania.[141] Like Maryland, Delaware is a transmission-constrained, net-importing state within the PJM control area.

141 Delaware Study at 27-28 (Delaware imports 37% of its generation).

1. **Deregulation Framework**

Delaware's Electric Utility Restructuring Act of 1999 ("Delaware Restructuring Act") deregulated the generation, sale, and supply of electricity.[142] The statute required Delmarva – Delaware's primary electric utility – to complete its transition to competition by September 20, 2002, for nonresidential customers and September 30, 2003, for residential customers. Del. Code Ann. tit. 26, § 1004 (2007).[143]

Delmarva began its phase-in of retail competition on October 1, 1999, pursuant to a settlement agreement with the Delaware Public Service Commission ("DE PSC").[144] Del. Code Ann. tit. 26, § 1004(a). In accordance with the statute, the agreement reduced residential rates by 7.5% and froze those rates through September 30, 2003. Order No. 5206, *Re Delmarva Power & Light Co.*, 1999 Del. PSC LEXIS 259, at *1 (Aug. 31, 1999); *see also* Del. Code Ann. tit. 26, § 1004(a) (the transition period for Delmarva's residential customers ends on September 30, 2003). The rate reduction included shopping credits, which represented the retail supply price for Electric Supply Service against which alternative suppliers compete. *Id.* at *4. The DE PSC extended the rate cap until May 1, 2006, as part of the 2002 settlement approving a merger between Delmarva and PEPCO. Order No. 5941, *In re Application of Delmarva Power & Light Co., Conectiv Communications, Inc., Potomac Elec. Power Co., & New RC, Inc., for Permission to Transfer Control of Delmarva Power & Light Co. & Conectiv Communications, Inc. Under the Provisions of 26 Del. C. §§ 215 & 1016*, 2002 Del. PSC LEXIS 151, at *4 (Apr. 16, 2002). As expiration of the rate cap approached, and recognizing that customers were facing substantial rate increases, Delaware enacted a phase-in for competitive rates until January 1, 2008. Del. Code Ann. tit. 26, § 1006(a)(3). Under the phase-in, rates increase incrementally with a final reconciliation on January 1, 2008, at which time customers began paying full rates and began repaying any deferred past due amounts. *Id.*[145] The statute offered the phase-in to all customers, regardless of whether they purchased generation from the default service or an alternative supplier, and allowed customers to opt out of the deferral plan and pay true rates starting on May 1, 2006. *Id.* More than 50% of customers opted out of the phase-in, choosing instead to pay the higher prices as they were incurred.[146]

---

142 *See* H.B. 10, 140th General Assembly (Mar. 31, 1999).

143 The Delaware Electric Cooperative's ("DEC") – Delaware's only other deregulated utility – transition period began on April 1, 2000, and ended on March 31, 2005, for all customers, but it had no generation of its own to divest. DEC could easily be re-regulated since the only effect would be to remove customer choice and restore its territorial monopoly. *See* Delaware Study at 7. Because DEC's re-regulation is not analogous to the Maryland utilities, we do not discuss it in this report.

144 Delaware Study at 14.

145 *See* "Delaware Electric Rate Increase: Phase-In Plan," *available at http://www.delmarva.com/home/choice/de/sosphasein/*.

146 Interview with Janis Dillard, Regulatory Policy Administrator, and David Bloom, Public Utilities Analyst, Delaware Public Service Commission (Sept. 17, 2007).

Delmarva recovered approximately $16 million in stranded costs from large industrial and commercial customers. Order No. 5231, *In re the Review of a Retail Competition Restructuring Plan Filed by Delmarva Power & Light Co. & the Determination of Transition Period Rates Pursuant to 26 DEL. C. §§ 1005(a) AND 1006(a)(1) (Filed Apr. 15, 1999)*, at ¶ 65 (Sept. 28, 1999). It negotiated stranded costs in a Side Letter Agreement that addressed issues not specified in the Delaware Restructuring Act. *Id.* at ¶18. The stranded costs became part of Delmarva's approved unbundled rates and were not a separate charge. The DE PSC declined to issue a decision about whether $16 million was an appropriate amount to recover, and instead opined that it had no basis to stop Delmarva from recovering the stranded costs through its existing unbundled rates. *Id.* at ¶ 65.

Although the DE PSC did not require Delmarva to divest its generation assets (Order No. 5206, at *6), Delmarva did ultimately transfer its generating facilities.[147] It sold some assets to third parties, but transferred many to Delmarva affiliates.[148] Delmarva did not share any of the profits of these sales with ratepayers.[149]

Delmarva's restructuring settlement effectively discouraged customers from switching to alternative suppliers. The deregulation statute permits knowledgeable customers to seek out cheaper prices from an alternative supplier, but the settlement agreement included provisions that protect the utility from loss of load. Customers who used more than 300 kW and chose an alternative supplier could not return to Delmarva's service during the rate freeze period without executing a one-year contract or paying market prices to reflect Delmarva's incremental costs of PJM supply. Customers using less than 300 kW could freely change suppliers. Order No. 5206, at *6. Although intended to deter gaming, this measure may have impaired the emergence of a competitive market.

2. <u>Factors Driving Delaware to Consider Modifying the Deregulated Framework</u>

Delaware experienced problems similar as other states and responded to the deficiencies that emerged under deregulation by seeking to reassert control over the market. Deregulation did not produce the anticipated lower rates. Residential rates increased by approximately 59% once rate caps expired.[150] Rates for small commercial customers rose by 67%, and rates for large commercial and industrial customers rose by

147 Delaware Study at 7.

148 Interview with Janis Dillard, Regulatory Policy Administrator, and David Bloom, Public Utilities Analyst, Delaware Public Service Commission (Sept. 17, 2007).

149 *Id.*

150 American Public Power Association, *Power Supply Procurement in Retail Choice States* (June 2007) (*available at* www.appanet.org/files/PDFs/Powersupplyretailchoicestates607.pdf) at 9.

118%.[151] As with rates in Maryland following deregulation, market changes, rising fuel prices, and unforeseen events (*e.g.*, Hurricane Katrina) sent prices skyrocketing, and the competitive market did not respond with compensating supply increases. Moreover, deregulation did not resolve Delaware's infrastructure problems, and rates rose due in part to a combination of several state-specific factors.

After deregulation, very little new generation was built. Delaware is not an ideal location for generators due to limitations on fuel availability and transportation to the peninsula, environmental and zoning constraints, and the rural nature of the load.[152] Moreover, the majority of Delaware's generating capacity is non-base load.[153] Very little new generation has been built since deregulation, so demand continues to exceed supply, creating higher prices.[154] Delaware has promoted a new interstate transmission line into Delaware, but it will come too late – no sooner than 2014 – to solve short-term problems.[155] In fact, the prospect of the new line bringing lower prices potentially deters construction of new generation because any new plants would be less profitable once new transmission opens new supply sources and competition.

Additional factors also contributed to rising prices. Delaware had substantial transmission congestion constraints within PJM, and in July 1999, the state faced a significant increase in congestion charges.[156] Steps taken as part of the 2002 merger between Delmarva and PEPCO significantly reduced transmission congestion, but it remains a problem because of Delaware's load growth and the limitations of the transmission system on the peninsula.[157] Consequently, congestion charges continued to drive prices up. The lack of free entry and exit from the market – caused in large measure by the generation constraints discussed above – has affected the level of competition in the deregulated wholesale market.[158] Because the wholesale market

---

151 *Analyst Concludes That Complete Re-Regulation of Delawares [sic] Electric Utility Industry is Not Feasible, Recommends Modified Approach*, Foster Electric Report, Report No. 507 (May 16, 2007) at 13.

152 Bruce Burcat, Janis Dillard, and Bob Howatt, *Transmission Congestion on the Delmarva Peninsula*, Presentation to the Federal Energy Regulatory Commission by the Delaware Public Service Commission (Feb. 28, 2002) at 5.

153 *Id.*

154 Interview with Janis Dillard, Regulatory Policy Administrator, and David Bloom, Public Utilities Analyst, Delaware Public Service Commission (Sept. 17, 2007).

155 Delaware Study at 29. As discussed *infra* at 47, the Mid-Atlantic Area National Interest Electric Transmission Corridorwas approved in October 2007 and includes Delaware.

156 Burcat et al. at 6. Congestion was one of the issues addressed in the 2002 merger between PEPCO and Delmarva. Order No. 5941, at *79-81.

157 Vantage Consulting, Inc., *Report to the Delaware Public Service Commission Regarding the Purchase of Full Requirements Wholesale Service for Fixed Price Standard Offer Service Customers*, at 9.

158 Interview with Janis Dillard, Regulatory Policy Administrator, and David Bloom, Public Utilities Analyst, Delaware Public Service Commission (Sept. 17, 2007).

determined the default retail rate following restructuring, there was no check on external factors that increased prices. Finally, electricity prices were higher in part due to Delaware's old, inefficient generation fleet.[159] To date, the wholesale market structure in Delaware has proven to be an inadequate tool for maintaining reasonable retail prices.

Deregulation did not stimulate a competitive retail market. As of May 2007, only one percent of residential customers switched to an alternative generation supplier when offered choice.[160] This represented about 15% of the residential customers' peak load.[161] Moreover, only two generation suppliers were currently certified to compete with Delmarva. The market for commercial and industrial customers was somewhat more successful, with 15% of nonresidential customers purchasing from an alternative supplier.[162] Many more generators competed for commercial and industrial customers, undoubtedly due to higher demand for their services.[163] Even with some success among nonresidential customers, only 2.5% of total customers were purchasing generation from alternative suppliers.[164] In a market with limited supply flexibility and an inability to respond to rising prices, customers have no reasonable options for relief, and policy makers concluded that the state must intervene.

3. Steps Taken to Re-regulate

The Delaware legislature responded to high prices and the deficient competitive market by passing the Electric Utility Retail Customer Supply Act of 2006 ("2006 DE Act"), which the governor signed on April 6, 2006. H.B. 6, 143rd General Assembly. The 2006 DE Act reinstated some DE PSC authority over the generation, supply, and sale of electricity while retaining retail choice. Del. Code Ann. tit. 26, § 1003. The 2006 DE Act's primary objective was price stability, although it also placed significant emphasis on environmental protection.[165] The statute required Delmarva to provide default service and returning-customer service, which "shall be treated as a public utility service or function."[166] *Id.* § 1003(a)(1). To ensure price stability and reliability, the 2006 DE Act focused on two main objectives: (1) long-term planning and diversification, and (2) creation of new generation. It also encouraged demand-side management.

---

159 *Id.*

160 Delaware Study at 22.

161 *Id.* at 22-23.

162 Delaware Study at 23.

163 *See* List of Certified Electric Suppliers (Updated Oct. 9, 2007) (*available at* http://depsc.delaware.gov/electric/elecsupplierinfo.pdf).

164 Delaware Study at 23.

165 Interview with Janis Dillard, Regulatory Policy Administrator, and David Bloom, Public Utilities Analyst, Delaware Public Service Commission (Sept. 17, 2007).

166 Returning customer service is electric supply service offered to customers with a peak monthly load of 1000 kW or more who have who have left SOS as of April 30, 2007 and then return to Delmarva for generation. Del. Code Ann. tit. 26, § 1001(17). Customers on returning customer service may return to SOS after twelve months of service. *Id.* § 1007(a).

(a) Integrated Resource Planning

The 2006 DE Act requires Delmarva to prepare an IRP every two years that "systematically evaluate[s] all available supply options during a 10-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost." *Id.* § 1007(c)(1). Delmarva must describe its supply and demand forecasts and submit a proposed resource mix – *e.g.*, a combination of long- and short-term PPAs, self-generation, RFP procurement from the wholesale market, and DSM programs – for the succeeding ten years. *Id.* In developing its IRP, the statute forbids Delmarva from relying solely on any one resource or purchase procurement process. *Id.* § 1007(c)(1)(a). Delmarva must consider multiple sources of power, but at least 30% of the resource mix has to be purchased from the regional wholesale market through auction or bid procurement. *Id.* The 2006 DE Act further requires Delmarva to explore thoroughly all reasonable short- and long-term procurement or demand-side strategies, and instructs Delmarva to detail its analysis of all options it considers, regardless of whether it implements them. *Id.*

In addition to these requirements, the 2006 DE Act also specifies a series of factors that Delmarva may consider in developing the IRP, with a focus on their "economic and environmental" value: (1) resource options utilizing innovative base load technologies, (2) resources beneficial to the environment, (3) facilities with an existing fuel and transmission infrastructure, (4) facilities utilizing existing industrial or brownfield sites, (5) supplies that promote fuel diversity, (6) supply options that support or improve reliability, and (7) resources that encourage price stability. *Id.* § 1007(c)(1)(b). The 2006 DE Act is very clear that Delmarva must consider all options for long-term price stability, and it grants the DE PSC broad authority to develop whatever rules and regulations it deems necessary to ensure the development of IRPs. *Id.* § 1007(c)(1)(c).

The 2006 DE Act also generally encourages Delmarva to diversify its supply by allowing it, subject to the DE PSC's approval, to (1) enter into short- and long-term power purchase contracts, (2) own and operate generation facilities, (3) build generation and transmission facilities, (4) invest in demand-side resources, and (5) take any other action the DE PSC approves to diversify its retail load. *Id.* § 1007(b).

With the 2006 DE Act, the legislature specifically laid out how Delmarva should develop its IRP, and it gave the DE PSC broad authority to ensure that Delmarva complies. The statute authorizes the DE PSC to oversee the development of the IRP (*id.* § 1007(c)(1)(a)), and further empowers the DE PSC to issue any rules and regulations it deems necessary to ensure Delmarva's development of the IRP. *Id.* § 1007(c)(1)(c). The DE PSC issued proposed regulations on January 1, 2008, but those regulations have not been finalized. *See* 3009 Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power and Light Company (Docket 60) (Jan. 1, 2008) (*available at* http://regulations.delaware.gov/AdminCode/title26/3000/3009.pdf). The proposed regulations require Delmarva to submit an IRP every two years that includes at least (a) a demand and energy forecast, (b) the resource options available to meet the demand and energy, (c) a recommended portfolio for meeting the demand and energy forecast, and an explanation for why Delmarva chose particular options, (d) an analysis of the risk and sensitivity of the recommended plan in comparison to other options also considered, (e) plan objectives by which to measure the plan's achievements, and (f) planning information for a 10-year planning horizon. *Id.*

On December 1, 2006, Delmarva filed its first IRP pursuant to the statute.[167] In May 2007, the DE PSC Staff asked the DE PSC to reject Delmarva's IRP on the grounds that it was "woefully insufficient," too limited in scope, and did not meet the requirements of the 2006 DE Act.[168] Delmarva opposed the Staff's request.[169] The DE PSC and Delmarva ultimately reached an informal agreement that Delmarva would modify and resubmit its proposed IRP.[170] Delmarva filed its updated IRP on March 5, 2008. The updated IRP included proposals in the areas of portfolio management, reliability, and demand response. Delmarva suggested that it actively manage a resource portfolio for procuring SOS customer energy requirements beginning as early as June 1, 2009. Delmarva Power & Light Co.'s Delaware IRP Update, *In re Integrated Res. Planning For the Provision of Standard Offer of Serv. by Delmarva Power & Light Co. PSC Docket No. 07-20 Under 26 Del.C. §1007 (c) & (d); Review of Initial Res. Plan Submitted Dec. 1, 2006 (Opened Jan. 23, 2007)*, at 18 (Mar. 5, 2008). As part of its proposal, Delmarva requested that the DE PSC authorize the creation of a Portfolio Working Group comprised of representatives from Delmarva, the DE PSC Staff, and the Delaware Division of the Public Advocate, which would establish proposed rules and guidelines for operating and managing the portfolio. *Id.* at 19. Delmarva proposed to meet reliability needs through transmission investments. *Id.* at 21-22. Finally, with respect to demand response, Delmarva offered several proposals, including establishing an Internet-based Portal to the PJM Demand Response Market to enable large customers to utilize PJM's market-based conservation options, establishing new direct load control programs for residential and small commercial customers, deploying advanced metering and establishing cost recovery methods for new demand response initiatives, decoupling revenue from sales to avoid disincentives in DSM programs, and creating an Advanced Metering Infrastructure ("AMI") Working Group to review and report on issues relating to AMI implementation and to review alternative dynamic pricing options. *Id*. at 23-24.

---

[167] Delmarva Light & Power Co. Integrated Resource Plan 2007-2016, DE PSC Docket No. 6-241 (Dec. 1, 2006) (*available at* http://depsc.delaware.gov/electric/dplirp/120106irprpt.pdf).

[168] *See* Motion by the Staff of Delaware Public Service Commission Seeking a Commission Order Rejecting Delmarva Power & Light Company's Integrated Resource Plan Submitted December 1, 2006, *In re Delmarva Power & Light Co.*, DE PSC Docket No. 07-20, (May 18, 2007), at 6.

[169] *See* Delmarva Power & Light Company's Response in Opposition to the Motion of the Staff of Delaware Public Service Commission Seeking a Commission Order Rejecting Delmarva Power & Light Company's Integrated Resource Plan Submitted December 1, 2006, *In re Delmarva Power & Light Co.*, DE PSC Docket No. 07-20 (June 8, 2007).

[170] Interview with Janis Dillard, Regulatory Policy Administrator, Delaware Public Service Commission (Oct. 9, 2007).

The DE PSC requested several clarifications to the March 5, 2008, IRP update, including additional information about the energy supply portfolio and a request for Delmarva to simulate Delaware's energy portfolio under three different long-term scenarios. *See* Letter from James McGeddes to Todd L. Goodman, *In re Delmarva Power & Light Co.* (Mar. 24 2008) (DE PSC Docket No. 07-20). On May 15, 2008, Delmarva filed its second IRP update to address the DE PSC's questions.[171] On September 10, 2008, the DE PSC issued a procedural schedule for reviewing and receiving comments on the proposed IRP, with evidentiary hearings scheduled for July 2009. Approved Procedural Schedule, *In the Matter of Integrated Resource Planning for the Provision of Standard Offer Supply Service by Delmarva Power & Light Company Under 26 Del. C. § 1007(c) &(d): Review of Initial Resource Plan Submitted December 1, 2006 (Opened January 23, 2007)*, Del. PSC Docket Number 07-20 (Sept. 10, 2008). Delmarva must file its next IRP on December 1, 2008.

(b) RFP for Long-term Contracts

As part of the IRP process, the 2006 DE Act requires Delmarva to submit a plan to secure long-term contracts, including issuance of an RFP for the construction of new generation within Delaware. Del. Code Ann. tit. 26, § 1007(d). The RFP must also include a proposed output contract between Delmarva and the new generation supplier that lasts between ten and 25 years. *Id.*

The statute authorizes the DE PSC to approve the RFP before its issuance to ensure that it recognizes the value of several priority factors under Delaware's public policy: (1) the use of new and innovative base load technologies, (2) long-term environmental benefits, (3) utilization of existing fuel and transmission infrastructure, (4) promotion of fuel diversity, (5) support or improvement of reliability, and (6) utilization of existing brownfield or industrial sites. *Id.* § 1007(d)(1). The 2006 DE Act also authorizes the DE PSC, the Director of the Office of Management and Budget, the Controller General, and the Energy Office (collectively, the "State Agencies") to evaluate and approve responses to the RFP. *Id.* § 1007(d)(3).

Delmarva submitted its proposed RFP for new generation on August 1, 2006.[172] An independent consultant evaluated the proposed RFP, and after input from the public, issued a final report. Order No. 7199, *In re Integrated Res. Planning for the Provision of Standard Offer Supply Serv. by Delmarva Power & Light Co. Under 26 Del. C. § 1007(c) & (d): Review & Approval of the Request for Proposals for the Construction of New Generation Resources Under 26 Del. C. § 1007(d) (Opened July 25, 2006)*, 2007 Del. PSC LEXIS 88, at *47-48 (May 22, 2007). The DE PSC and the Energy Office's designated representatives heard oral argument in a public session to consider the independent consultant's final report, at which time Delmarva opposed certain of the

---

171 *Available at* http://depsc.delaware.gov/electric/PSC%20Docket%2007-20%20IRP%20Update.pdf.

172 *See* Delmarva Power & Light Company's Compliance Filing and Application for Approval of Proposed Request for Proposals, *In re Delmarva Power & Light Co.*, DE PSC Docket Nos. 06-241 and 04-391 (Aug. 1, 2006) (*available at* http://depsc.delaware.gov/electric/irp/dppropltcontr.pdf).

report's recommendations. Ultimately the DE PSC adopted the independent consultant's recommendations over Delmarva's objections. The DE PSC also retained jurisdiction over all future disputes. *Id.* at *65-66.

Delmarva issued its RFP on November 1, 2006, seeking new generation that must be operational by June 1, 2013.[173] The RFP also specified that Delmarva would purchase up to 400 MW of capacity, energy, and ancillary services under a PPA, which must last from ten to 25 years. Delmarva could not purchase more capacity than the capacity produced from the new generation under the PPA. Additionally, Delmarva would buy Renewable Energy Credits from renewable projects on an as-specified schedule.[174] Delmarva will pay separately for capacity and energy, and bidders must offer fixed prices or prices adjustable pursuant to a specified public utility index.[175]

Bluewater Wind LLC ("Bluewater"), Conectiv Energy Supply, Inc. ("Conectiv"), and NRG Energy, Inc. ("NRG") each submitted proposals by the December 22, 2006, deadline. Bluewater's bid proposed a wind park producing 600 MW of electricity based at one of two possible sites,[176] and offered either a 600 MW capacity plant limited to 400 MW of energy or a 600 MW plant selling two-thirds of its energy to Delmarva.[177] Bluewater offered two PPA options, one for 20 years and one for 25 years. Each included fixed prices that would escalate at a yearly inflation rate of 2.5%.[178] Conectiv offered to build a 180 MW unit using combined cycle technology with natural gas as the primary fuel and low-sulfur light petroleum product as the secondary fuel.[179] Conectiv's bid included a ten-year PPA with an option for an additional five years. Conectiv's pricing included a one-time adjustment applicable to a third of the capacity and all of the on-peak energy based upon a five-year futures gas price index. After the first year, the on-peak prices would be adjusted annually based on a coal-based index and the Gross

---

173 Delmarva Power & Light Company Request for Proposals Instructions to Bidders (Nov. 1, 2006).

174 *Id.* at 2.

175 *Id.* at 23.

176 *See* Blue Water Wind LLC, Executive Summary (*available at* http://depsc.delaware.gov/electric/irp/rfp_c.shtml).

177 DE PSC Staff Report on the Term Sheets for Proposed Power Sales to Delmarva Power (Oct. 29, 2007) (*available at* http://depsc.delaware.gov/electric/irp/staffrpt102907.pdf) ("DE PSC Staff Report") at 6.

178 New Energy Opportunities, Inc., La Capra Associates, Inc., Merrimack Energy Group, Inc., and Edward L. Selgrade, Esq., Presentation to Delaware Public Service Commission, Delaware Office of Management & Budget, Delaware Energy Office, and Delaware Controller General, *Summary of Bid Evaluation Report, Delmarva Power RFP for Long-Term Power Supplies From New Generation In Delaware, PSC Docket No. 06-241* (Feb. 27, 2007), (*available at* http://depsc.delaware.gov/electric/irp/evalrpt0227fin.pdf) ("Summary of Delmarva Bid Evaluation Report") at 4.

179 *See* Conectiv Energy, *In re Delaware Power & Light Co. Request for Proposals for New Generation* (Dec. 21, 2006) (*available at* http://depsc.delaware.gov/electric/irp/conectiv_redact.pdf) at 1-2.

Domestic Product Implicit Price Deflator.[180] NRG proposed to sell 400 MW of energy and unforced capacity credits from a new 600 MW carbon-capture ready, clean coal power plant.[181] It offered a PPA term of 25 years though it also offered an option for only 20 years.[182] NRG's pricing proposal included capacity payments adjusted yearly based on the CPI-NE and energy prices adjusted annually by the CPI-NE and coal-based index.[183]

After reviewing all of the proposals, in May 2007, the State Agencies ordered Delmarva to negotiate with Bluewater for a long-term PPA for wind power. Delmarva also negotiated with both Conectiv and NRG for the provision of backup power.[184] Delmarva issued revised term sheets for the proposed agreements with Bluewater, Conectiv, and NRG in September 2007.[185] On October 29, 2007, the DE PSC Staff recommended that all of the proposed PPAs – Bluewater's primary bid and the NRG and Conectiv backup agreements – be rejected.[186] The revised Bluewater proposal had substantially increased prices and delayed the project's completion by an extra year. As part of its revised proposal, Bluewater used a price escalator that the DE PSC Staff considered unreasonable because it shifted too many risks and costs to ratepayers without providing them any potential economic benefits. The DE PSC Staff determined that the proposed agreement is not in the public interest because of these high costs and risks.[187] The DE PSC Staff recommended against the proposed backup agreements with Conectiv and NRG because they were dependent upon the Bluewater PPA.[188] On December 4, 2007, the State Agencies ordered Delmarva and Bluewater to continue negotiating a PPA for the provision of off-shore wind power. Order No. 7328, *In re Integrated Res. Planning for the Provision of Standard Offer Supply Serv. by Delmarva Light & Power Co. Under 26 DEL. C. § 1007(c) & (d): Review & Approval of the Request for Proposals for the Construction of New Generation Resources Under 26 DEL. C. § 1007(d) (Opened July 25, 2006)*, 2007 Del. PSC LEXIS 212, at *49 (Dec. 4, 2007). Delmarva submitted a revised PPA on December 10, 2007, but the State Agencies could not reach a consensus to approve the PPA and voted on December 18, 2007, to table the matter. Order No. 7440, *In re Integrated Res. Planning for the Provision of Standard Offer Supply Serv. by Delmarva Power & Light Co. Under 26 DEL. C. § 1007(c) & (d): Review & Approval of the Request for Proposals for the Construction of New Generation Resources Under 26*

---

180 Summary of Delmarva Bid Evaluation Report at 5.

181 *See* NRG Energy Inc., Proposal for Proposed Indian River IGCC Facility -Volume 1, Part 1, Construction of Innovative Base Load Generation for Delaware (Dec. 17, 2006) (*available at* http://depsc.delaware.gov/electric/irp/nrg_redact_vol1a.pdf) at 5; DE PSC Staff Report at 6.

182 DE PSC Staff Report at 6.

183 Summary of Delmarva Bid Evaluation Report at 6.

184 DE PSC Staff Report at 7.

185 *Id.* at 8.

186 *Id.* at 23-24.

187 *Id.* at 24.

188 *Id.*

DEL. C. § 1007(d) (Opened July 25, 2006), 2008 Del. PSC LEXIS 94, at *2 (Sept. 2, 2008).

Following hearings held by the Delaware Senate Energy and Transit Committee, Delmarva and Bluewater resumed negotiations in May 2008, and signed a final PPA on June 23, 2008, under which Delmarva will purchase energy, capacity, and a specified quantity of renewable energy credits and other “environmental attributes” produced by 200 MW of installed capacity from a new wind farm to be built off the coast of Rehoboth Beach. *Id.* The final PPA is half the size of the PPA proposed in December 2007, provides a lower price for renewable energy credits, with a 350% multiplier for those credits Delmarva received from the off-shore wind farm to meet Delaware’s renewable portfolio standards, gives Bluewater termination rights for two years, and contains a limited most favored customer clause to protect ratepayers if Bluewater sells energy to third parties. *Id.* at *2-3. Two days after the final PPA was executed, and with the unanimous support of the General Assembly and the governor, Delaware passed a law establishing the 350% renewable energy credit multiplier and empowered the DE PSC to establish a non-bypassable surcharge to distribute the costs of the PPA to Delmarva’s entire customer base. *Id.* at *3. With both the DE PSC Staff and the State Agencies supporting it, the DE PSC approved the PPA on September 2, 2008. *Id.* at *9. The DE PSC also ordered that the backup arrangements for additional generation be addressed in the IRP process. *Id.* at *10.

Despite the ultimate approval of Bluewater’s June 2008 proposal, one concern raised about the RFP process was that the DE PSC veered from the requirements of the 2006 DE Act by ordering Delmarva to negotiate with Bluewater for a PPA instead of issuing a new competitive RFP. Focusing solely on negotiations with Bluewater may have prevented consideration of other proposals offering greater long term benefits and cost-effectiveness.

(c) Demand Side Management

The 2006 DE Act also grants the DE PSC authority to require Delmarva to implement DSM programs to reduce energy consumption. Del. Code Ann. tit. 26, § 1008(b)(1)(b). The statute further authorizes the DE PSC to issue any rules and regulations it deems necessary to require Delmarva to develop DSM programs. *Id.* § 1008(b)(1)(c). Delaware has taken steps to increase demand-side energy efficiency, most notably with the creation of the Sustainable Energy Utility (“SEU”). The SEU is designed to operate as a nonprofit organization to work with customers to increase energy efficiency (*e.g.*, through the use of energy efficient appliances).[189] Despite the authority granted by the 2006 DE Act, the DE PSC has neither compelled any DSM measures nor enacted any rules or regulations related to demand-side efficiency.

---

[189] *See* Delaware Gen. Assembly, Sustainable Energy Util. Task Force (*available at* http://www.seu-de.org).

4. Mechanisms Considered But Not Yet Implemented

The 2006 DE Act created a foundation for modifying deregulation, but the DE PSC is still navigating its way through the options the statutes authorize. The 2006 DE Act sought the construction of new generation, but an agreement was only reached two years later and the agreement was for substantially less new generation than intended originally.. Further complicating the issue, the U.S. Department of Energy recently announced construction of a transmission line – the Mid-Atlantic Area National Interest Electric Transmission Corridor – that will run from West Virginia through Delaware to New York.[190] Because increased transmission creates the potential for customers to purchase cheaper generation out-of-state, this new corridor could defer or eliminate the need for Delaware's investment in the construction of new generation.

Nancy Brockway – a DE PSC consultant hired to assess Delaware's restructuring options – made several recommendations to the Delaware General Assembly in a May 2007 report. First, she suggested that Delaware use a democratic stakeholder process to establish goals and priorities for its electricity market. Second, she recommended that Delaware establish a portfolio approach to supply resources so that diversification could reduce price and reliability risks. Third, she recommended that Delaware create a State Power Authority to become the default service provider. Finally, she recommended that Delaware limit retail choice to commercial and industrial customers.[191] With the exception of Delmarva's proposed portfolio approach in its updated IRP, Delaware has not acted on these recommendations.

C. Illinois

Illinois relies primarily on nuclear and coal generation in almost equal proportions.[192] Exelon Energy Co., LLC ("Exelon"), the largest Illinois generator with about 20% of the state's total generating capacity, owns most of the nuclear power plants, which are located primarily in the northern part of the state. The bulk of the coal-fired capacity in Illinois is held by three companies, Midwest Generation LLC (a subsidiary of Edison Mission Energy), Ameren and Dominion Generation, which, together account for

---

190 *See* U.S. Dept. of Energy, Press Release, ***DOE Designates Southwest Area and Mid-Atlantic Area National Interest Electric Transmission Corridors*** (Oct. 2, 2007) (*available at* http://www.energy.gov/news/5538.htm) (announcing designation of Mid-Atlantic Area National Interest Electric Transmission Corridor) ; *see also* http://www.energy.gov/media/MidAtlantic_Corridor_Map091707.pdf (map showing that Delaware is within the Mid-Atlantic Area National Interest Electric Transmission Corridor).

191 Delaware Study at 64.

192 *See* CNN Special: Fueling America Electricity Generation (2006) (*available at* http://www.cnn.com/SPECIALS/2006/fueling.america/interactive/popup.electric/us.map.electric.swf) at Illinois.

about 27% of the state's total generating capacity. Its fleet of coal plants is now more than 30 years old, and its nuclear reactors are all over 20 years old.[193]

Unlike Maryland, Illinois is one of the largest electric power exporters in the nation.[194] Especially in the southern part of the state, Illinois generates more power than required to serve the in-state load, and exports power to neighboring states. Despite its exports, areas of Illinois including Chicago, an area north and west of Chicago to the Iowa border, and an area spreading from Chicago southwest to Peoria and Springfield were transmission constrained at least as recently as April 2006.[195]

1. Summary of Deregulation Framework

The Electric Service Customer Choice and Rate Relief Law of 1997 (Public Act 90-0561) ("1997 Ill. Act") adopted a phased-in approach to electric deregulation that permitted retail choice for different customer classes in stages. For example, the 1997 Ill. Act permitted large industrial and commercial customers to choose their suppliers in October 1999, while the remaining industrial and commercial customers began electric choice at the end of 2000, and residential customers in May 2002. 1997 Ill. Act § 5-935, Sec. 16-104 (a).

Although the 1997 Ill. Act did not require generation asset divestitures, Illinois' larger utilities – Commonwealth Edison Company ("ComEd") and the Ameren Companies (Ameren CILCO, AmerenCIPS and Ameren IP) – divested some of their assets to non-affiliated entities and transferred their remaining generation assets to affiliated companies.[196] The Illinois Commerce Commission ("ICC") had limited oversight of the assets divestitures, in that it could only disapprove a divestiture transaction if it found that the transaction would render the utility unable to provide safe and reliable service or would result in a strong likelihood that the utility would seek a base rate increase during the transition period. *Id.* § 5, Sec. 16-111(g)(4)(vi). Some of Illinois' smaller utilities retained their generation assets, although their customers could still choose an alternate supplier.[197]

---

193 Interview with H. Stoller, Director of Energy Division, Illinois Commerce Commission (Sept. 17, 2007).

194 *Id.*; 2007 Adequacy Report at 2, n. 3 (In 2004, Illinois was one of the highest exporters of electricity).

195 Argonne National Laboratory and University of Illinois at Urbana-Champaign, *Evaluating the Potential Impact of Transmission Constraints on the Operation of a Competitive Electricity Market in Illinois* (Apr. 2006) at xiii.

196 Order, *In re Commonwealth Edison Co.*, ICC Docket No. 00-0369 (Aug. 17, 2000) at 4; Central Illinois Public Service Co., Quarterly Report (SEC Form 10-Q) (May 15, 2005) at 5.

197 *See, e.g.*, MidAmerican Energy Company, *Illinois Customer Choice Suppliers' Handbook* (May 1, 2002) *(available at* http://www.midamericanenergy.com/pdf/illinois_choice/supgddftplntxt5.pdf) at 5.

As part of the merger between PECO Energy Company and Unicom Corporation (then the parent company of ComEd) that formed Exelon, ComEd transferred its nuclear generation assets to an Exelon affiliate at book value – calculated as of December 31, 2000 – in return for ComEd common stock.[198] This transaction produced no proceeds for ComEd.[199] The asset transfer also included a power purchase agreement ("PPA"), as described below. Prior to the Exelon merger, ComEd sold most of its coal, oil, and gas-fired plants (9,772 MW) to Edison Mission Energy ("EME").[200] ComEd also sold some fossil fuel assets to affiliates of the Southern Company and Dominion Resources, Inc.[201] ComEd divested its fossil fuel plants to entities that were not affiliated with either ComEd or Exelon.[202] ComEd sold these assets at market value with EME paying about $5 billion to acquire 9,621 MW of the coal, gas, and oil fired generation.[203] As with the Exelon asset transfer, these sales also included PPAs that continued through 2004.[204]

Ameren transferred its generation assets to affiliated companies. Central Illinois Public Service ("AmerenCIPS") transferred its generating assets to AmerenEnergy Generating Company ("Genco") on May 1, 2000.[205] AmerenCIPS transferred its generating assets at historical net book value in exchange for a subordinated promissory note worth $552 million and 1,000 shares of Genco stock.[206] This transfer also included a PPA, discussed below. AmerenCILCO transferred its generating assets to Ameren Energy Resources Generating Company ("AmerenEnergy") on October 3, 2003.[207]

The 1997 Ill. Act froze rates during the transition period to a competitive market and, for residential customers, included a 15% reduction below the base rates at the beginning of 1997. *Id.* § 5, Sec. 16-111(b). Residential customers received most of these rate reductions in August 1998, with a subsequent reduction in May 2002. *Id.* During the rate freeze, utilities could recover their increased operating and fuel costs, pursuant to a statutory formula. *Id.* § 5, Sec. 16-111(d). The rate freeze was to expire at the end of 2004, but the legislature extended the freeze and transition period for another two years because, at that time, there were insufficient suppliers willing to serve residential customers on a competitive basis. Public Act 92-0537 § 5, Sec. 16-102 (extending mandatory transition period through January 1, 2007), 16-111 (freezing rates during

198 Commonwealth Edison, Current Report (SEC Form 8-K) (Jan. 12, 2001) Item 2 at 2.

199 *Id.*

200 Order, *In re Commonwealth Edison Co.*, ICC Docket No. 00-0369 (Aug. 17, 2000) at 4.

201 *Id.*

202 Synapse Survey at 25.

203 Edison International, Quarterly Report (SEC Form 10-Q) (Aug. 12, 1999) at 15.

204 Order, *In re Commonwealth Edison Co.*, ICC Docket No. 00-0369 (Aug. 17, 2000) at 4.

205 AmerenEnergy Generating Company, Quarterly Report (SEC Form 10-Q) (May 31, 2001) at 2.

206 Central Illinois Public Service Co., Quarterly Report (Form 10-Q) (May 31, 2001) at 5.

207 Order Accepting and Suspending Affiliate Sales, Subject to Refund, and Establishing Hearing Procedures, *Ameren Energy Marketing et al.*, FERC Docket No. ER07-205-000, 117 FERC ¶ 61,362 (Dec. 29, 2006) at 2.

mandatory transition period). The bundled rate freeze ended on January 1, 2007, with the end of the mandatory transition period.

Utilities continued to supply electricity to those customers who had not switched to competitive suppliers through default service. During the rate freeze period – *i.e.*, through January 1, 2007 – utilities procured residential customers' default service electricity and ancillary services through PPAs. ComEd executed a PPA with Exelon to supply all of ComEd's power supply through 2004.[208] For 2005 and 2006, ComEd would obtain power from Exelon up to the capacity of the nuclear facilities and purchase its remaining power from other generators in the market.[209] The PPA specified a schedule of prices for on- and off-peak energy by month for the length of the PPA, based on ComEd's cost-of-service associated with the nuclear facilities, prices under the Fossil Agreements, and projections of energy market prices.[210] ComEd did not pay a separate capacity charge.[211] Under the PPA, ComEd is only required to purchase and pay for the energy needed to serve its load. ComEd also entered into a PPA after selling its coal- and gas-fired plants to EME. Until 2004, ComEd was obligated to "make a capacity payment [at cost] for the units under contract and an energy payment for the electricity produced by these units."[212] After transferring its nuclear generating units to Exelon, ComEd transferred its rights under this PPA to Exelon.

When the Ameren utilities transferred their generating facilities to the Ameren unregulated generation companies, the utilities entered into PPAs with their affiliated generators to meet the utilities' supply needs. AmerenCILCO obtained its full requirements for power and energy under a Power Supply Agreement ("PSA") with Ameren Energy Resources Generating Co.[213] AmerenCIPS entered into a PPA with Ameren Energy Marketing to meet its energy and capacity requirements.[214] AmerenIP purchases the majority of the electricity that it supplies to retail customers through long-

208 Order, *In re Commonwealth Edison Co.*, ICC Docket No. 00-0369 (Aug. 17, 2000) at 3.

209 *Id.*

210 *Id.* at 6.

211 *Id.*

212 Edison International, Quarterly Report (SEC Form 10-Q) (Aug. 11, 2000) at 17.

213 Order Accepting and Suspending Affiliate Sales, Subject to Refund, and Establishing Hearing Procedures, *Ameren Energy Marketing et al.*, FERC Docket No. ER07-205-000, 117 FERC ¶ 61,362 (Dec. 29, 2006) at 2.

214 *Id.*

term PPAs.[215] Ameren's and ComEd's PPAs and PSAs expired on December 31, 2006.[216]

Additionally, during the transition period, AmerenIP and ComEd offered "an unbundled, market-based generation option called the Power Purchase Option ('PPO') to non-residential customers."[217] PPOs allow non-residential customers to opt out of default service, but still obtain power from the distribution utility at an estimated market price set for one year.[218] Electric utilities must provide PPO service to be able to collect transition charges.[219] The ICC regulated the rates for the unbundled energy, and approximately 15,000 customers received PPO service in 2005.[220] This represented a growth of 5,000 customers over the previous year, with many of those new PPO service customers switching from competitive suppliers.[221] The ICC and consumer groups expressed concern over the use of PPOs because the rates were not market-based, but did allow commercial customers to receive power at a reduced price.[222] Effective with the end of the mandatory transition period the utilities are no longer permitted to collect transition charges.

Beginning January 1, 2007, Illinois' utilities procured default service electricity and ancillary services through a competitive "simultaneous, multiple round, descending clock auction."[223] The Illinois auction consisted of two sections – a fixed-price section and an hourly-price section – and bidders could register for one or both of these sections.[224] The ICC, along with its consultant, conducted the bidding for these sections simultaneously and the auction proceeded in rounds. The auction manager announced

---

215 *See, e.g.*, Dynegy Illinois Inc., SEC Form 8-K (Mar. 29, 2006), Ex-99.3 at 12; *Dynegy Announces Completion of Illinois Power Sale*, Business Wire (Oct. 1, 2004) (*available at* http://findarticles.com/p/articles/mi_m0EIN/is_2004_Oct_1/ai_n6216262) (discussing the PPA between AmerenIP and Dynegy Inc.).

216 *See, e.g.*, *id.*; Order, *In re Commonwealth Edison Co.*, ICC Docket No. 00-0369 (Aug. 17, 2000) at 3; Order Accepting and Suspending Affiliate Sales, Subject to Refund, and Establishing Hearing Procedures, *Ameren Energy Marketing et al.*, FERC Docket No. ER07-205-000, 117 FERC ¶ 61,362 (Dec. 29, 2006) at 2.

217 Illinois Commerce Commission, *Competition in Illinois Retail Electric Markets in 2005* (May 2006) ("2005 Competition Report") at i.

218 Synapse Survey at 25.

219 2005 Competition Report at 1.

220 *Id.* at i, iii.

221 *Id.* at iii.

222 Report of Chairman's Fall 2001 Roundtable Discussions Re: Implementation of the Electric Service Customer Choice and Rate Relief Law of 1997 (Nov. 2001) (*available at* http://www.ieu-ohio.org/information/in_the_news/pdf/IllCommRpt.pdf) at 19.

223 Auction Format, Illinois Auction (*available at* http://www.illinois-auction.com/index.cfm?fa=gen.for).

224 *Id.*

the price for each product,[225] and suppliers bid on how many tranches[226] they were willing to supply at that price.[227] If generators bid for more tranches than the utility needed, the auction manager decreased the price by a specified percentage, determined based on the amount of supply in excess of demand.[228] For the next round, the auction manager announced the lower price, and generators again bid on how many tranches they would supply at the new price.[229] This process continued until the number of tranches bid equaled the number of tranches needed. Illinois caps the number of fixed-price tranches a particular generator could supply at 35%.[230]

The auction products are specific to utility, customer type, and supply period. For example, ComEd's residential and small commercial full requirement contracts covered periods of 17, 29, and 41 months, while its larger commercial customer contracts were only for 17 months.[231] For the 2006 auction, 21 bidders registered to bid and 16 generators won at least some portion of the load.[232] On the whole Exelon won 27.1% of the fixed-price tranches awarded, while Ameren Energy Marketing won 9% of the total.[233]

Illinois also instituted procedures to encourage retail switching. For example, the ICC required utilities to educate the public about consumer choice, to offer the option of single-billing, to implement real-time pricing, and to use accounting techniques that would promote consumer choice from the suppliers' perspective.[234] On the other hand, as we discuss below, the 1997 Ill. Act imposed conditions for switching that may have impeded the exercise of retail choice.

2. Factors Driving Illinois to Modify the Deregulated Framework

Increases in residential rates for 2007 became the symbol of deregulation's failure in the public's eye and the impetus for re-regulation. In 2007, rates for residential

---

225 In the Illinois auction, a "product" is a specific category of load for a specific supply period. *Id.*

226 In the Illinois auction, a "tranche" is a fixed amount of load. *Id.*

227 *Id.*

228 *See id*.

229 *Id*.

230 Announcements, Illinois Auction (*available at* http://www.illinois-auction.com/index.cfm?fa=gen.annDtl&id=A9A28079-EE5A-2992-E2C940289AA26D4D).

231 Rate Information, Illinois Auction, (*available at* http://www.illinois-auction.com/index.cfm?fa=gen.rate).

232 Affidavit of Craig R. Roach, Ph.D., *Illinois v. Exelon Generation Co., LLC*, FERC Docket No. EL07-47-000 (June 6, 2007) at 4.

233 Illinois Commerce Commission, *The September 2006 Illinois Auction: Post-Auction Public Report of the Staff* (Dec. 6, 2006) at 9.

234 *See, e.g., Illinois Choice: Residential Customer Handbook*, Ameren, (*available at* http://www.ameren.com/IlChoice/ADC_CC_ResidentialcustomerHandbook.asp).

customers in ComEd's service area, the northern half of the state, increased 24% above the rate freeze levels.[235] Residential rates in Ameren's service area, the southern portion of the state – which had been lower during the rate freeze – increased 55%, bringing them to the same level as those in the north.[236] The ICC and State Assembly did not phase in these increases, so customers absorbed them all at once.

Illinois' attempts to encourage retail competition have not succeeded to the extent envisioned under the 1997 Ill. Act. As of September 2007, only one residential customer was receiving electricity from an alternate supplier.[237] In ComEd's service area, 15.7% of small commercial and industrial customers (those customers purchasing less than 1 MW) received electricity from alternate suppliers, but in areas served by Ameren companies, fewer than 10% of small commercial and industrial customers purchased from alternate suppliers.[238] Only large commercial and industrial customers (those customers purchasing more than 1 MW) uniformly purchased from competitive suppliers, ranging from 86.1% in AmerenCIPS' territory to 94.5% in AmerenCILCO's territory.[239] The utilities created one barrier to commercial customers' switching shortly before commercial customers could choose suppliers in October 1999, by executing long-term contracts with the most attractive customers, thereby locking them in for the length of the contract.[240] Some commercial customers may also have spurned offers from alternate suppliers because they had chosen PPO service, which offered service rates that were often lower than competitive rates.[241]

Some customers may not have switched to competitive suppliers in part because switching in Illinois is particularly time consuming and expensive. For example, the ICC must certify each competitive supplier and requires an original signature on a contract between the competitive supplier and the customer. 1997 Ill. Act § 45, Sec. 2EE(2). Through the end of 2006, customers who switched providers also paid a CTC to reimburse utilities for their stranded costs.[242]

---

235 *Illinois Rate Increases Predicted to Diminish State Economy*, Electrical Contractor (Apr. 2007) (*available at* http://www.ecmag.com/index.cfm?fa=article&articleID=7408).

236 *Facts About Illinois Rates*, Ameren (July 2007) (*available at* http://www.ameren.com/MediaRoom/ADC_FactsAboutIllinoisRates.asp).

237 *See* Illinois Commerce Commission, Switching Statistics for the Ameren Companies, ComEd, MidAmerican, and Mt. Carmel Electric (*available at* http://www.icc.illinois.gov/industry/publicutility/energy/switchingstatistics.aspx).

238 *Id.*

239 *Id.*

240 *See* Report of Chairman's Fall 2001 Roundtable Discussions Re: Implementation of the Electric Service Customer Choice and Rate Relief Law of 1997 (Nov. 2001) (*available at* http://www.ieu-ohio.org/information/in_the_news/pdf/IllCommRpt.pdf) at 5.

241 2005 Competition Report at 6-8.

242 Synapse Survey at 23.

Although the ICC Staff and the independent Auction Monitor found no evidence of collusive behavior or other anti-competitive actions by bidders, in March 2007, the Attorney General's office raised concerns about the reasonableness of the procurement process,[243] focusing particularly on the descending clock auction format, and the utilities' ties to their affiliates. The Attorney General also sought to promote the use of renewable fuels and clean Illinois coal, while trying to reduce demand. The Illinois Power Agency Act (Public Act 95-0481) ("IPA Act"). These factors led the Attorney General to advocate a new power procurement process for the utilities' retail customers that will ultimately make a new state agency responsible for procurement.[244]

3. Steps Taken to Re-regulate

(a) Illinois Power Agency

On August 28, 2007, Illinois' Governor signed The IPA Act, which created a new Illinois Power Agency ("IPA"). The IPA Act represents a modification of the electric restructuring process that started in 1997, and gives the IPA authority to oversee a competitive power procurement process. The IPA Act also provides for approximately $1 billion in rate relief primarily for residential and small non-residential customers over four years. IPA Act § 5-935, Sec. 16-111.5A(d). It includes a declaration that markets for large commercial and industrial electric customers are competitive (*id.* § 5-935, Sec. 16-113) and imposes new energy efficiency and demand response requirements on the state's utilities, as well as new renewable portfolio standards. *Id.* § 5-935, Sec. 12-103. In April 2008, the Illinois' Governor appointed Mark Pruitt – previously an energy procurement specialist with the University of Illinois – to be the executive director of the IPA.[245]

i) Electricity Demand Estimation

The IPA Act authorizes the IPA to "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time." *Id.* § 1-5(7)(A). The IPA prepares these plans with the help of the Illinois utilities, who must annually provide a range of five-year load forecasts to the IPA that include hourly data representing high-, low-, and expected-load scenarios for eligible retail customers. *Id.* § 5-935, Sec. 16-111.5(b), (d)(1)-(2). The IPA evaluates these forecasts for accuracy and plausibility in order to determine a final load forecast for each utility.[246] *Id.* § 5-935, Sec. 16-111.5(a), (b). The IPA then incorporates

243 Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Sept. 25, 2007).

244 *Id.*

245 Sol Lieberman, *Chief of New Illinois Power Agency Named; Role of Buying, Selling Electricity as Yet Undefined*, Medill Reports (Apr. 15, 2008) (*available at* http://news.medill.northwestern.edu/chicago/news.aspx?id+85937).

246 Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Nov. 6, 2007).

these forecasts into a five-year procurement plan that includes hourly load analysis, analysis of any demand side and renewable energy initiatives, a plan for meeting the expected load requirements, and proposed procedures for balancing loads. *Id.* § 5-935, Sec. 16-111.5(b), (d). After drafting the procurement plans, the IPA receives public comments through public hearings within each utility's service area and submits a final procurement plan within 14 days after the end of the comment period. *Id*. 5-935, Sec. 16-111.5(d)(2). The ICC must then approve the procurement plan, including expressly approving the load forecast used in the procurement plan. *Id*. § 5-935, Sec. 16-111.5(d)(4). Utilities will purchase any supply shortfall in the spot market.

The IPA submitted its first procurement plan to the ICC on October 20, 2008. Illinois Power Agency, *Initial Power Procurement Plan to the Illinois Commerce Commission*, ICC Docket No. 08-0519 (Oct. 20, 2008) (the "IPA Plan"). The IPA Plan details a procurement approach intended to secure electricity commodity and associated transmission services while keeping prices to consumers low and stable. *Id.* at 1-2. As required by the IPA Act, Ameren and ComEd submitted five-year hourly load projections and described the statistical methods and assumptions underlying the projections. *Id.* at 10. The IPA reviewed and accepted Ameren's and ComEd's forecasts (*see id.* at 10-16) and additionally recommended hedging expected peak energy requirements in July and August at 110% to reduce weather-related price spikes. *Id.* at 2. Based on the projections, the IPA developed portfolios for Ameren and ComEd to meet their required energy and capacity requirements. *Id.* at 28-56. The IPA suggests procuring the energy load ultimately determined to be required in tranches: 35% procured two years in advance of delivery, 35% procured one year in advance of delivery, and 30% procured in the year in which power is to be delivered. *Id.* at 26. It expects this approach to provide the highest probability of obtaining the lowest long-term electricity costs. *Id.* The ICC is currently accepting comments regarding the Plan from interested parties. After assessing and potentially incorporating these comments, the ICC will approve the Plan in January 2009 and begin its implementation.[247]

Because this is the first IPA plan, the IPA also further explained its procurement planning process. The IPA described its planning process as a continuous-cycle planning process involving eight steps. The IPA (1) works with utilities to define the State's electricity needs, (2) identifies risks and unknowns, (3) selects appropriate mitigation tools (*e.g.*, procurement methods and products), (4) tests risk management options through statistical models, (5) selects the optimal products and procedures to deliver the most stable costs, (6) submits the Plan for approval by the ICC, (7) coordinates procurement according to the Plan, and (8) monitors prices and stability and reorients the Plan as necessary to address market conditions and new risks and opportunities. *Id.* at 7. The IPA also pointed out certain areas it could not include in this plan because of timing, but would like to include in future plans. These include (a) using market-price triggers to procure electricity when market conditions are favorable, (b) holding procurements more

---

[247] Interview with R. Zuraski, Senior Economist, Illinois Commerce Commission Energy Division (Nov. 10, 2008).

than once-per-year, (c) including demand reduction strategies, (d) including energy supply contracts longer than three years, and (e) using shorter procurement cycles. *Id.* at 2-3.

ii) RFP Process

Because the IPA submitted its first procurement plan in October 2008, it has not yet issued an actual RFP. The IPA Act gives the IPA broad powers to "[c]onduct competitive procurement processes to procure" default service. *Id.* at § 1-5(7)(B). With this mandate, the IPA will no longer use the descending clock auction but will implement a system similar to Maryland's RFP process.[248] *Id*. § 5-935, Sec. 16-111.5(e). In order to participate, suppliers must pass a pre-qualification test, which includes an evaluation of credit-worthiness, compliance with procurement rules, and agreement to the standard form contract. *Id*. § 5-935, Sec. 16-111.5(e)(1). The Attorney General's Office believed that the descending clock auction procedure permitted improper information exchange between the utility and its affiliates. To curb that suspected abuse, the IPA will conduct a blind, sealed-bid RFP process in which best price will be the only criteria for selecting among prequalified suppliers beginning in 2009.[249] *Id*. § 5-935, Sec. 16-111.5(e)(4). For this reason, the IPA Act also requires that generators agree to standard contract forms and credit terms and instrument. *Id.* § 5-935, Sec. 16-111.5(e)(2)

Once the generators submit the bids, the IPA will assess the bids against predetermined benchmarks.[250] *Id*. § 5-935, Sec. 16-111.5(e)(3). Similar to Maryland's PAT, these confidential benchmarks will estimate the market price for each product available for bids. *Id*. The benchmarks will be based on price data for similar products for the same delivery period and same delivery hub, or different delivery hubs after adjusting for that difference. *Id.* The IPA would disregard bids that do not meet the benchmarks. If more than enough bids meet the benchmarks so that there is an excess supply, the IPA will allow the utilities to negotiate directly with suppliers to further reduce the price.[251] The IPA will rigorously oversee this process to ensure that the utilities give no preference to their affiliates. If not enough bids meet the benchmarks, the IPA will hold another round of procurements in an effort to obtain bids that meet the benchmarks. After the Commission approves the procurement results, the utilities must execute the standard contracts with the winning bidders. *Id.* § 5-935, Sec. 16-111.5(g).

iii) Generation Construction

---

248 David Nicklaus, *Market Prices Keep Power On in Illinois*, St. Louis Post-Dispatch (Aug. 12, 2007) (*available at* http://www.stltoday.com/stltoday/business/columnists.nsf/davidnicklaus/story/C9191C4D2CEE52D7862573340008B4F8?OpenDocument).

249 Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Sept. 25, 2007).

250 Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Sept. 25, 2007).

251 *Id*.

The IPA Act also empowered the IPA to construct new generation. *See* IPA Act § 1-20(a)(3). It would seek to develop electric generation or co-generation that would use Illinois coal, renewable resources, or both. Preference will be given to technologies that enable carbon capture and to sites in locations where the geology is suitable for carbon sequestration. *Id.* § 1-80(c). The IPA may sell power at cost from its generating plants to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois. *See id*. § 1-20(a)(4). This construction would emulate the public-private partnership used in the United Kingdom. The IPA had hoped to fund the new generation using the full faith and credit of the state, but the state objected and the IPA will issue bonds to cover new generation's capital cost. *Id*. § 1-57(a).

The IPA will also relax the criteria for utilities to build their own generation plants. The ICC had previously permitted utilities to initiate new generation only if they could show a need for electricity in the state.[252] Because Illinois is one of the largest electricity exporters, utilities could rarely convince the ICC of the need for new generation. Utilities can now develop new generation if they demonstrate that they would be able to produce cheaper electricity than they could acquire on the open market. *Id.* § 5-935, Sec. 16-111.5(p). This more flexible standard may encourage utilities to construct their own generation plants, initiating a gradual move towards re-regulation.

iv) Promote Renewable Energy and Energy Efficiency

Lastly, the IPA Act requires the IPA to implement programs to both promote the use of renewable energy and decrease demand. With respect to renewable energy, the IPA's procurement plans must include at least two percent renewable energy by June 1, 2008, increasing to ten percent by June 1, 2015, and reaching 25% by June 1, 2025. IPA Act § 1-75(c)(1).

Similarly, the IPA must promote energy efficiency to decrease demand, but the reductions are more modest, requiring only a two percent reduction by 2015. *Id*. § 5-935, Sec. 12-103(b). The utilities may use any means to meet these requirements, including intermediate milestones prior to 2015. If a utility fails to meet the percentages laid out in the statute in the first three years, then the IPA may impose a "symbolic" penalty of $1 million. *Id*. § 5-935, Sec. 12-103(i). If the utility continues to miss the required benchmarks, the IPA will take control of the energy efficiency program and dictate demand reduction measures.[253] *Id*.

The $1 billion rate relief included in the IPA Act for small customers – which has received the most public attention – was negotiated as part of comprehensive rate relief program associated with the development of the IPA Act. *Id*. § 5-935, Sec. 16-

[252] Interview with H. Stoller, Director of Energy Division, Illinois Commerce Commission (Sept. 17, 2007).

[253] Interview with S. Hedman, Senior Assistant Attorney General, Office of the Illinois Attorney General (Sept. 25, 2007).

111.5A(d). The rate relief package will be funded primarily by contributions from Exelon affiliated companies (including ComEd) and Ameren affiliated companies. Exelon Generation will provide $747 million, ComEd will provide $53 million, Ameren companies will provide $150 million, Midwest generation will provide $25 million, Dynegy will provide $25 million, and MidAmerican will contribute $1 million.[254]

Approximately $488 million of that amount will reduce rates for ComEd's residential and small commercial customers. *Id.* § 5-935, Sec. 16-111.5A(e). As a result, Illinois will give each of ComEd's customers a credit of $4 to $13 per month.[255] This credit would decrease the rate increases for ComEd's customers by about half so that the northern part of the state will experience only a 13.5% rate hike.[256] Exelon agreed to these payments in order to avoid another rate freeze and the prospect of further generation taxes the state threatened to levy.[257] Ameren will also apply approximately $488 million towards rate relief for its residential and small commercial customers. *Id.* § 5-935, Sec. 16-111.5A(f).

(b) Other Methods Used By Illinois

Illinois has implemented several other programs that are designed to modify the restructuring process, but most are too recent to assess their effectiveness. As part of the re-regulation process, utilities are permitted to enter five-year "swap" contracts with suppliers.[258] These swap contracts would be included in the utilities' procurement plans as pre-existing contracts, and the IPA will not include this amount in its procurement plans.[259] The Ameren Illinois Utilities entered into a five-year swap contract covering 800 MW of around-the-clock ("ATC") energy for June 1, 2009 through May 31, 2010, and 1,000 MW of ATC energy for June 1, 2010 through December 31, 2013. Commonwealth Edison entered into a swap contract for 2,000 MW of ATC energy for June 2009 through May 2010 and 3,000 MW of ATC energy for June 2010 through May 2012.[260] The swap contracts will permit utilities to hedge future market uncertainty by effectively establishing the price for the power purchased and stabilizing rates over a five-year period.[261]

---

254 *ComEd to Participate in Comprehensive, Statewide Settlement of Electric Rate Debate*, Electric Energy Online (Aug. 1, 2007) (*available at* http://electricenergyonline.com/IndustryNews.asp?m=1&id=71494).

255 *Id.*

256 *Id.*

257 *Id.*

258 Swap contracts work similarly to fixed price contracts in that they allow a utility to hedge against future market volatility.

259 Exelon Corp., SEC Form 8-K (July 24, 2007) at 4.

260 IPA Plan at 30, 45.

261 *Id.*

While the General Assembly has taken steps toward re-regulation, it has also acted to give the competitive market a boost. The Retail Electric Competition Act created the Office of Retail Market Development ("RMD Office"). *See* Public Act 94-1095, Retail Electric Competition Act of 2006, 94th Gen. Assemb., § 20-110 (Ill. 2006). The RMD Office will "actively seek[] out ways to promote retail competition in Illinois," and will monitor existing competitive conditions in Illinois, identify barriers to competition, and actively explore and propose solutions. *Id.* at § 20-110. The RMD Office is responsible for designing a detailed plan to promote competition in residential and small commercial markets in the most expeditious manner possible. *Id.* at § 20-120.

D. New Jersey

Because New Jersey falls within the PJM control area, those wholesale markets and conditions in neighboring or nearby states affect New Jersey's reliability, cost, and environment.[262] Like Maryland, New Jersey imports about one-quarter of its energy needs[263] and is transmission constrained.

1. Summary of Deregulation Framework

New Jersey enacted deregulation legislation in February 1999, initially permitting customers to choose alternate suppliers beginning in August 1999.[264] The EDECA authorized the New Jersey Board of Public Utilities ("NJ BPU") to determine whether utilities needed to divest their generating assets or merely separate their generating assets from regulated transmission and distribution.[265] Utilities could recover their stranded costs, subject to NJ BPU approval, through a market transition charge collectible over eight years. EDECA at § 13(i).

At the time of deregulation, four electric utilities operated in New Jersey: Public Service Electricity & Gas ("PSE&G"), Jersey Central Power & Light ("JCP&L"), Conectiv, Inc. , and Orange & Rockland Electric ("Rockland") (collectively referred to as "EDCs").[266] Conectiv, Inc. sold its nuclear units but could not find a buyer for its fossil-

---

262 *New Jersey Report on Electricity* at 4 (*available at* http://nj.gov/emp/home/docs/pdf/061013e.pdf).

263 Delaware Study at 28.

264 *Status of State Electric Industry Restructuring Activity as of February 2003* (*available at* http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf) at New Jersey; *see* Electric Discount and Energy Competition Act, N.J. Public Law 1999, Chapter 23 (Feb. 9, 1999) ("EDECA"). Technical problems forced a delay in implementing customer choice until November 1999. American Public Power Association, *New Jersey* (May 2006) (*available at* http://www.appanet.org/files/pdfs/NewJersey051006.pdf) at 1.

265 Robert Olson, *New Jersey Restructuring Bill Passes Both Houses, Providing Limited Exit Fee Exemption, Renewables Requirement and Securitization*, PMA Online (Feb. 1999) (*available at* http://www.retailenergy.com/statelin/9902olsn.htm); EDECA § 11.

266 New Jersey Deferred Balance Task Force Report (*available at* http://www.state.nj.us/deferredbalances/pdf_s/deferred%20balances%20task%20force%20report.pdf) at 14-16.

fueled units, JCP&L sold a majority of its generating assets, and Rockland sold all its generation capacity.[267] PSE&G transferred its generating assets to its affiliate, PSEG Power.[268] Conectiv, Inc. recovered $440 million of nuclear-related stranded costs and costs for restructuring above-market power contracts, JCP&L recovered $307 million of stranded costs for the Oyster Creek nuclear plant, and PSE&G recovered $2.4 billion in stranded costs, mostly related to its nuclear units.[269]

The EDECA required each EDC to provide default service – called Basic Generation Service ("BGS") – to customers who did not purchase electricity from competitive suppliers. EDECA at § 9. The NJ BPU approved staggered three-year, internet-based descending clock auctions to procure full-requirements contracts. *See* Proposal for Basic Generation Service Requirements to be Procured Effective June 1, 2008, *I/M/O Provision of Basic Generation Service For The Period Beginning June 1, 2008*, NJ BPU Docket No. ER07060379 (July 2, 2007) ("2008 BGS Proposal") at 3. The auction process consists of two concurrently held auctions: one for larger customers on an hourly-price plan ("BGS-CIEP"), and one for smaller commercial and residential customers on a fixed-price plan ("BGS-FP"). *Id.* The EDCs propose the auction structure, the NJ BPU accepts comments on the structure, and the NJ BPU ultimately approves it. *Id.*; *see* EDECA at § 9(d). For the 2008 auction, the NJ BPU approved the EDCs' proposed auction structure in all respects relevant for this discussion on November 28, 2007. Letter Order, *I/M/O the Provision of Basic Generation Service for the Period Beginning June 1, 2008 – Electric Distribution Companies' ("EDCs")BGS Compliance Filings*, NJ BPU Docket No. ER07060379 (Nov. 28, 2007). The approved 2008 structure follows the basic structure used for default service since February 2002.

The BGS-FP auction seeks offers for the supply of full-requirements tranches of each EDC's BGS-FP Load for a three-year period. 2008 BGS Proposal at 23. Each tranche is a fixed percentage of the EDC's total BGS-FP Load. *Id.* Each year, the utility procures one-third of its yearly required supply. *Id.* Suppliers bid the number of tranches they are willing to fulfill at the stated price. *Id.* The price decreases if the supply exceeds the number of required tranches. *Id.* The auction ends when the number of tranches bid equals the number of tranches the EDCs need to procure. *Id.* at 23-24. During the auction, suppliers may also set their "Exit Price," *i.e.*, the lowest price at which they are willing to purchase additional tranches. Boston Pacific Co., Inc., *Final Report on the 2007 BGS FP and CIEP Auctions and the RECO SWAP RFP*, NJ BPU Docket No. EO06020119 (Apr. 30, 2007) ("BP 2007 Final Report") at 9. If the number of tranches bid is less than the number of tranches available, the tranches are sold at the Exit Price. *Id.* The EDCs pay winning suppliers a seasonally adjusted price using a factor greater than one for the summer months and lower than one for the winter months. 2008 BGS Proposal at 24.

---

[267] *Id.*

[268] *Id.* at 15.

[269] *Id.* at 14-16; Conectiv, Inc., Annual Report (SEC Form 10-K) (Apr. 23, 2003) at "Securitization."

To ensure competitiveness during the auction, no single supplier can win more than a specified number of an EDC's tranches or more than the aggregate, state-wide amount of BGS-FP load. *Id.* For the 2007 auction, an aggregate load cap was 19 out of 51 available tranches (37%). BP 2007 Final Report at 3. Bidders can assess migration risk at various price levels using a spreadsheet that converts auction prices into customer rates. 2008 BGS Proposal at 24. Winning bidders must accept standardized non-price terms and conditions, thus permitting bids to be evaluated based solely on price. BP 2007 Final Report at 2. For the auction that took place in 2007, 13 suppliers won tranches to supply electricity in 2008, 2009, and 2010. *Id.* at 3. For 2007, New Jersey fixed-price residents receive power from 17 suppliers (*i.e.*, 17 suppliers won tranches of 2007 electricity in the 2004, 2005, and 2006 auctions). *Id.* at 4. EDECA also requires competitive suppliers and BGS suppliers to meet the state's renewable energy requirements associated with the load they serve.

2. New Jersey's Response To Deregulation Concerns

Despite competitive BGS auctions, in 2007, residential customers' rates increased between ten percent and 14%.[270] Actual auction prices increased by 55% between 2005 and 2006.[271] As in other states, although electric rates have increased, suppliers have not responded by building new generation, and customers have not switched from default service to alternate suppliers. At the same time, New Jersey's electric load has increased, further exacerbating congestion created by transmission constraints. Between 1996 and 2006, New Jersey's demand for energy grew three times faster than its population.[272] Consequently, New Jersey continues to be heavily reliant on generation from other states.[273]

Rather than focusing on constructing new generation, New Jersey has concentrated on stimulating demand response. It is currently developing an Energy Master Plan ("EMP"), with an overarching goal of "[r]educ[ing] projected energy use by 20% by 2020 and meet[ing] 20% of the State's electricity needs with Class 1 renewable energy sources by 2020. The combination of energy efficiency, conservation, and renewable energy resources, should allow New Jersey to meet any future increase in demand without increasing its reliance on non-renewable resources."[274] Governor Corzine's press release announcing formation of the EMP described it as "a long-term

270 Delaware Study at Appendix I at 19 (citing http://www.bpu.state.nj.us/bome/news.shtml?46-06).

271 Comments of Public Advocate Ronald K. Chen Presented at a Legislative Hearing Before the Board of Public Utilities, *I/M/O The Provision of Basic Generation Service For the Period Beginning June 1, 2008*, NJ BPU Docket No. ER07060379 (Sept. 20, 2007) at 1.

272 Press Release, N.J. Office of the Governor, Oct-03-06 Governor Corzine Announces Initial Phase of Energy Master Plan, (Oct. 3, 2006) ("Governor Corzine's EMP Press Release") (*available at* http://nj.gov/governor/news/news/approved/20061003.html).

273 *Id.*

274 Energy Master Plan Goals (*available at* http://nj.gov/emp/about/goals.html).

energy vision for the state that plans for the state's energy needs through 2020."[275] The Governor further stated that the EMP "will assure New Jersey residents and businesses access to a stable, steady supply of affordable energy while maintaining and expanding our state's leadership position in the fight against global warming."[276]

The EMP includes the views of the various affected stakeholders including generators, EDCs, government agencies, power purchasers, and citizens' groups. The EMP was finally published in October 2008.[277] It enumerates five goals, which seek to reduce peak demand while increasing energy conservation, energy efficiency, and clean energy, and to develop an energy infrastructure that supports the EMP, ensures reliability of the system, and provides consumers with tools to manage their energy consumption. The EMP identified three action items for developing New Jersey's energy infrastructure. First, the State should work with utilities to develop master plans through 2020 that are responsive to the goals of the EMP. [278]These plans should identify the upgrades utilities' require to meet the EMP's goals and identify the structures of the programs the utilities will propose to meet the State's 2020 energy consumption targets. The utilities must develop such individual master plans by October 2009. Second, the DEP, BPU, and the Economic Development Authority will develop economic and regulatory incentives to spur clean generation construction.[279] The BPU staff will also develop a list of the regulatory and statutory changes that are necessary to make cogeneration technology available to more customers. Third, the State should ensure a balance between supply and demand that will ensure reliability, serve the State's greenhouse gas targets, and provide energy at a reasonable price.[280] This action item requires the State Energy Council to issue a report by the end of 2009 addressing the concerns with, and the viability of, nuclear energy. The BPU staff, DEP staff, and local gas distribution companies will also conduct a comprehensive analysis and future needs assessment to ensure the stability of prices of regional natural gas and liquid natural gas. The EMP also suggests working with PJM to modify or replace RPM and to shape PJM's planning of the electric transmission system to better protect New Jersey's economy and the environment.[281]

Simultaneously, the NJ BPU organized a BGS Working Group to evaluate steps that can be taken as part of the BGS process to reduce demand. The BGS Working Group was expected to provide its final recommendations to the NJ BPU in the spring of 2007, but delayed the release pending completion of the EMP. The EMP directed the

---

275 Governor Corzine's EMP Press Release.

276 *Id.*

277 New Jersey Energy Master Plan, (Oct. 2008) (*available at* http://www.state.nj.us/emp/docs/pdf/081022_emp.pdf) ("Energy Master Plan").

278 *Id.* at 76-77.

279 *Id.* at 78-79.

280 *Id.* at 79-81.

281 *Id.* at 93-94.

BPU to "intensify its examination" of the BGS auction process and concept through a transparent, public proceeding to be completed before any auction in 2009.[282]

E. **Other States' Approaches for Addressing Flaws in Deregulated Markets**

Other states have also taken steps to address problems developing in their deregulated markets, and some of their approaches may be instructive for Maryland.

Although Michigan's electric customers may choose competitive suppliers, regulated utilities must continue to serve any customers that do not purchase power from a competitive supplier.[283] Michigan has deregulated its retail market but maintains regulatory control over the retail access generation price.[284] Because customers could switch between regulated and competitive markets, few suppliers built new generation in Michigan, and those that did built gas-fueled units.[285] Michigan's base load generating fleet is, on average, 48 years old.[286] Concerned about volatile prices associated with gas-fueled plants and general uncertainty about the Midwest Independent Transmission System Operator ("MISO") wholesale markets, the Michigan Public Service Commission assessed its electricity needs over the next 20 years, and a January 2007 report, *Michigan's 21st Century Electric Energy Plan* ("Michigan Energy Plan), proposed three policy initiatives: (1) allowing utilities to build new generation plants, (2) requiring load serving entities to supply ten percent of their energy sales from renewable energy by the end of 2015, and (3) creating an Energy Efficiency Program.[287]

The Michigan Energy Plan concluded that even with aggressive DSM and energy efficiency, Michigan had to build one new base load plant no later than 2015.[288] The Plan proposes that if a utility wants to build a new plant, it can either build the plant and then seek recovery under the traditional "used and useful" option, or file an IRP demonstrating that a new plant is necessary.[289] Under the second approach, the IRP, must detail how the utility would use energy efficiency, renewable energy, transmission, existing regional resources, and new generation to meet its customers' needs.[290] If the plant is deemed necessary, the utility could build it, but must competitively bid the

---

282 Energy Master Plan at 96.

283 Public Sector Consultants Inc., *Market Structures and the 21st Century Plan* (Sept. 2007) at 1.

284 Kenneth Rose and Karl Meeusen, *2006 Performance Review of Electric Power Markets, Review Conducted For the Virginia State Corporation Commission* (Aug. 2006) at 35.

285 Michigan Public Service Commission, *Michigan's 21st Century Electric Plan* (Jan. 2007) at 13.

286 *Id.* at 13.

287 *Id.* at 3-7.

288 *Id.* at 12-13.

289 *Id.* at 3-4.

290 *Id.* at 17.

engineering, procurement, and construction.[291] The Michigan Energy Plan does not recommend competitive bidding for long-term generation capacity secured through a PPA because PPAs may be viewed as utility debt, which could increase the utility's required rate of return, thereby increasing ratepayers costs.[292] Michigan is currently assessing how to meet its Plan's goals, *e.g.*, repealing its deregulation legislation and fully re-regulating, fully deregulating, or introducing new legislation to reduce the risks of building new generation.[293]

New Hampshire is partially deregulated, but still requires Public Service of New Hampshire ("PSNH") – which supplies 70% of New Hampshire's electricity – to file "Least Cost Integrated Resource Plans" ("LCIRPs"). New Hampshire was one of the first states to begin deregulating, but lawsuits delayed implementation. By the time the parties resolved the lawsuits, the California energy crisis and apparent problems in other states led New Hampshire to prohibit PSNH from divesting its fossil and hydro generation assets without first finding that such a sale is in the economic interest of PSNH retail customers.[294] N.H. Rev. Stat. Ann. § 369-B:3-a. Although PSNH still owns generation, it may not build or purchase new generation plants, and none of New Hampshire's other utilities may own any generation plants.

New Hampshire still requires that electric utilities file a biannual LCIRPs with the New Hampshire Public Utility Commission ("NH PUC"). N.H. Rev. Stat. Ann. § 378:37 *et seq.* LCIRPs must (1) forecast future electrical demand, (2) assess DSM programs, supply options, and transmission requirements, (3) provide for diversity of supply resources, (4) integrate demand-side and supply-side options, (5) assess the plan's impact on compliance with the Clean Air Act Amendments, and the National Energy Policy Act, and (6) assess the plan's long and short-term environmental, economic, and energy price and supply impacts on the state. *Id.* at § 378:38.

Recognizing that PSNH's obligations in a deregulated market are different than in a regulated market, the NH PUC specified the factors PSNH had to include in its LCIRP: (1) electric energy and demand forecasts for delivery and energy services under high-, low-, and base-case scenarios, (2) the resource balance over the planning period, (3) the proposed resource plan to balance resources, and (4) a description of the process used for selecting the mix of demand-side and supply-side resources.[295] More specifically, PSNH must:

---

291 *Id.* at 4.

292 *Id.* at 19.

293 *Id.* at 16.

294 *Electric utilities partly deregulated in NH*, The Union Leader (Manchester, NH) (Apr. 22, 2007).

295 Order Approving Partial Settlement Agreement and Resolving Disputed Issues, *2004 Least Cost Integrated Resource Plan*, NH PUC Docket No. 04-072, Order No. 24,695 (Nov. 8, 2006) at 23-24.

- Include a five-year planning horizon if the NH PUC excludes new generation options from the supply-side assessment, but include a horizon that is as long as the single longest lead time required for resource options if the NH PUC include new generation options.[296]

- Develop load forecasts for delivery and energy services for the adopted planning horizon and include a detailed discussion of the methodology used to develop the forecast assumptions regarding customer movement to competitive suppliers, plan load forecasts on a customer class basis, plan load forecasts showing adjustments for losses, economic development, DSM, and self-generation, offer explanations of the changes in forecasted load growth, and provide broader load forecast scenarios that include higher than expected economic activity and electricity prices.[297]

- Include the difference (on an energy and capacity basis) between its generation and committed wholesale purchases and projected requirements based on the most current reference load forecast.[298]

- Identify all reasonably available resource options to meet the projected resource balance over the planning period (assuming the NH PUC determines that new generation should be included) and include the methodology used to evaluate the cost-effectiveness of such resources.[299]

- Include generic cost information regarding the construction or acquisition of new generation capacity to meet forecasted demand. The evaluation should consider the environmental compliance costs of each option, fuel diversity benefits of each option, the availability of each option at the time of system peak, and whether each option will promote price stability.[300]

- Compare demand-side and supply-side resource options by measuring the avoided costs associated with not having to purchase additional supplemental power or building new generation capacity.[301]

- Describe its hedging strategy, including the types of products PSNH intends to purchase, the timing of the purchases, the time periods when it

---

[296] *Id.* at 2.

[297] *Id.* at 3.

[298] *Id.*

[299] *Id.* at 3-4.

[300] *Id.* at 24-25.

[301] *Id.* at 26.

will purchase the products (*e.g.*, peak or off-peak), and the shortfall PSNH will meet with the products.[302]

- Describe how it will meet environmental compliance requirements, including a cost-benefit analysis of all reasonably available alternatives to its existing strategy for meeting existing or anticipated SO_2 regulations, the magnitude and timing of NO_x reductions, methods to comply with New Hampshire's Clean Power Act or proposed regional or federal programs, and alternatives for complying with potential state and federal mercury emissions regulations.[303]

- A description of integrating demand-side and supply-side resources in a manner that meets current and future needs at the lowest reasonable cost to consumers.[304]

New Hampshire's Senate Bill 140, which became law in July 2007, directs the NH PUC to facilitate discussions regarding upgrading transmission in the northern part of the state and directs the State Energy Policy Commission to determine whether electric distribution companies should be allowed to invest in small scale generation resources.[305] The NH PUC must report by December 1, 2007, on the status of the existing transmission system, the current process for siting, constructing, and financing transmission upgrades and expansion, the approximate costs of potentially appropriate transmission upgrades, approaches pursued by other states to encourage transmission expansion related to renewable generation, and actions the NH PUC has taken to advance New Hampshire's transmissions interests.[306]

Although Virginia did not completely deregulate and its price caps do not expire until 2010, it elected to re-regulate in part because retail competition had not developed as anticipated. Virginia's restructuring act, codified at Virginia Code § 56-576, *et seq*., did not require incumbent utilities to divest their assets, but it did require them to functionally separate their generation, retail transmission and distribution, under the Virginia State Corporation Commission's ("SCC") direction. Virginia Code § 56-590(A)-(B). Indeed, Virginia's two largest utilities – Dominion Virginia Power ("Virginia Power") and American Electric Power-Virginia ("AEP-Virginia") – did not divest their assets.[307] The Virginia General Assembly further exempted Virginia's third

302 *Id.* at 4-5.

303 *Id.* at 5-6.

304 *Id.* at 6.

305 *See* Senate Bill 140, An Act Relative To Transmission Upgrades, The Process For Siting Renewable Generation Facilities, and the Study of Demand Response Programs and Distributed Generation.

306 *Id.* at 364:1.

307 Commonwealth of Virginia State Corporation Commission, Report to the Commission on Electric Utility Restructuring of the Virginia Assembly, *Energy Infrastructure Data Collection* (July 1, 2003) ("Energy Infrastructure Report") at 7; Commonwealth of Virginia State Corporation

largest utility – Kentucky Utilities – from the restructuring act's requirements because it did not have to provide competitive retail electric energy in the other states it serviced.[308]

AEP-Virginia, as well as Allegheny Power and Delmarva, made retail choice available on January 1, 2002.[309] Virginia Power phased retail choice in between January 1, 2002, and January 1, 2003, by offering retail choice to one-third of its customers at a time.[310] Since they opened their service territories to competition, no competitive service providers ("CSPs") have registered with Allegheny Power or AEP-Virginia, while one CSP fully registered with Delmarva and six CSPs and five aggregators registered with Dominion Power.[311] As of August 1, 2007, one CSP served 1,280 residential customers and 18 commercial customers in Dominion Power's territory and another served 4 non-residential customers in Delmarva's territory.[312] No other retail customers purchased electricity from CSPs.

In April 2007, the Virginia General Assembly approved an act amending Virginia's electric regulation laws. *An Act to Amend and Reenact §§ 56-233.1, 56-234.2, 56-235.2, 56-235.6, 56-249.6, 56-576 through 56-581, 56-582, 56-584, 56-585, 56-587, 56-589, 56-590, and 56-594 of the Code of Virginia, to amend the Code of Virginia by adding sections numbered 56-585.1, 56-585.2, and 56-585.3, and to repeal §§ 56-581.1 and 56-583 of the code of Virginia, relating to the regulation of electric utility service.* S.B. 1416/H3068 (Apr. 2007) ("VA Restructuring Act"). The VA Restructuring Act returns Virginia's regulated utilities to cost-of-service rates with a return-on-equity component, although the Commission may approve utilities' performance-based rates. VA Restructuring Act § 56-235.2, 56-235.6, 56-585.1. Rates remain capped until December 31, 2008, after which the Commission must initiate rate-making proceedings to set the new rates. *Id.* §§ 56-582(F), 56-585.1. Utilities may seek rate adjustments to recover costs associated with creating and implementing demand-side-management, conservation, energy efficiency, and load management programs, participating in renewable energy portfolio standard programs, and participating in projects that the SCC finds necessary to comply with state or federal environmental laws or regulations. *Id.* § 56-585.1(A)(5). The SCC may approve construction of new power plants if they are required by public convenience and necessity. *Id.* § 56-580(D).

Commission, News Release, *SCC Separates Generation Service from Delivery Service for Virginia's Electric Utilities* (Dec. 18, 2001) ("SCC News Release") at 1.

308 Commonwealth of Virginia State Corporation Commission, Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly And the Governor of the Commonwealth of Virginia, *Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia* (Sept. 1, 2007) ("2007 Status Report") at 2 n.2.

309 *Id.* at 4.

310 *Id.*

311 *Id.*

312 *Id.* at 4, 8.

IV. Analysis of Maryland's Re-regulation Options

As we discuss earlier in this Report, a number of states have taken tentative steps toward re-regulation, but no state has yet blazed an incontrovertible path from deregulation back to the vertically integrated model that was the norm for almost all of the twentieth century. Even in the face of unsettling rate shocks and disappointing development of new generation resources, states have been cautious about such a radical course shift after less than a decade of deregulation experience. Moreover, the stimuli that led to a wave of deregulations have not disappeared. Customers remain averse to assuming large capital costs for generation facilities that may turn out to have been unnecessary or too expensive. Utilities have not demonstrated dramatically improved management that is likely to match efficiency gains achieved by many merchant generators. Regulators have not yet implemented formulas that instill incentives for productivity and innovation comparable to those in competitive markets.

Nevertheless, some form of re-regulation may be able to address chronic and seemingly intractable flaws in the current scheme. In assessing its options, the State should first consider the inescapable tradeoffs among costs, risks, and benefits. Regrettably, there is no free ride, and regardless of the structure chosen, customers will, in the end, bear most of the costs created by the inherent risks in development of electric generation. After evaluating the factors that should guide the State in choosing a path forward, we will analyze the qualitative pros and cons for a broad range of possible approaches to re-regulation, some of which may be used in combination: (1) a full return to vertically integrated utility ownership of all required generation facilities based on traditional cost-of-service compensation; (2) long-term utility contracts for or direct ownership of new in-state generation or demand resources; (3) direct State ownership of or contracting for new generation facilities through a state power authority; (4) comprehensive integrated resource planning to direct and control development of new resources; and (5) aggressive efforts to shape PJM's FERC-regulated wholesale electricity markets for Maryland's benefit.

A. Regulatory Tradeoffs Among Direct Costs, Risks, and Benefits

In one sense, electricity regulation provides a framework for allocating risks, costs, and opportunities for rewards. Because no one reasonably proposes unfettered electric industry competition with no regulation at all, policy makers must decide the appropriate level of government control that produces an optimal balance of customer costs, risks, and benefits. These elements are interrelated, however. Lower costs may implicate greater risks and reduced benefits. Shifting risks to others almost always entails a cost and may reduce opportunities for gains.

All risk implies an associated dollar cost because no party will voluntarily bear a risk without being compensated. Not surprisingly, the risk-free interest rate is lower than any other interest rate that includes an element of risk. To the extent that re-regulation shifts investment risks from merchant generators to utilities and ultimately to their retail customers, those customers assume an additional risk cost that cannot be disregarded.

Consequently, the State's analysis of re-regulation options should include the cost of bearing that risk – even if that cost cannot be fixed precisely. Alternatives often involve tradeoffs between non-dollar risk costs that customers assume and must bear and direct dollar costs that customers pay in order to avoid risk. An accurate evaluation should assess both risk costs and direct dollar costs and seek a solution that minimizes the combined costs to customers.

Retail customers will always pay both the direct and indirect costs associated with risk, and the price of electricity must reflect the risk inherent in generation investments. Thus, even if customers assume part of the risk – *e.g.*, by owning or contracting for new generation – thereby reducing the price that they pay for electricity, they will bear additional costs if the risks materialize. For example, if customers, through their utilities, buy, build, or contract for a nuclear power plant, they will be entitled to energy at the nuclear unit's variable production costs, which may be below market energy prices that are based on the marginal cost of the last unit required to serve demand – typically a gas-fired unit with higher marginal costs. At the same time, however, customers will pay the cost of capital and depreciation on a very expensive unit and will bear the risk that capital costs could increase to the point that they exceed the savings achieved by getting energy at the unit's low variable cost. If retail customers effectively own a nuclear plant through their utility, they also assume the risk that the plant may no longer be needed or that it may have to be shutdown for safety reasons (*e.g.*, an accident at another nuclear power plant). The risk cost is the reduced value of the asset if the risk arises multiplied by the probability that the risk will occur. Given the number of uncertainties and lack of reliable data, precisely estimating such costs is often virtually impossible. Nevertheless, policy makers should consider very real risk costs in assessing re-regulation options.

Even though retail customers ultimately pay all risk costs, policy makers and regulators can take steps to manage those risks or to assign them to the party most able to control them, thereby reducing overall costs. The State, on behalf of retail customers, should logically assume reasonable risks if doing so will reduce dollar costs by more than the expected cost of the associated risk. The State may be in the best position to minimize the total costs of achieving its goals if it – rather than merchant generators or utilities – controls new investment decisions to ensure that they are consistent with the State's priorities. For example, by acquiring or contracting for renewable generation resources that entail greater risks than private investors are willing to assume at market-based prices, the State may be able to achieve its environmental and generation reliability objectives more economically than through subsidies or elaborate exceptions to competitive market rules that may be designed to stimulate market investments but may do so inefficiently.

Merchant generators' priorities will be uniformly profit driven, incorporating market, financial, operating, and other risk factors. Unless market rules – which are themselves a form of regulation – are perfectly tuned to send investment signals that exactly match the State's priorities, merchants may make investment decisions that increase retail customers' costs and do not provide the intended benefits. For instance, merchant generators may have strong incentives to maintain the status quo – *e.g.*, no new generation – in order to keep LMPs and UCAP prices high. Merchant generators may also profit by holding out the prospect of substantial new generation on the horizon (*e.g.*, a large nuclear plant) that would lower prices thereby discouraging competitive suppliers from entering the market. Similarly, merchant generators may be unwilling to assume the risk of new generation investment when new transmission lines threaten to reduce its value by facilitating imports of lower-cost, out-of-state electricity and when they have no backstop PPA to assure recovery of their costs. Merchants merely act in their own self-interests to maximize their profits, but structural deficiencies in market performance, coupled with generators' profit-seeking strategies, may precipitate additional customer costs and reliability concerns that may not be remediable within the current deregulation framework, at least in the near term.

As a consequence of deregulation, merchant investors assumed much of the generation ***investment risk*** that had rested entirely with retail customers under cost-of-service regulation. For example, private generation investors must accept the risk that new transmission lines will be built into Maryland, thereby relieving constraints, lowering energy and capacity prices, and reducing the economic value of their assets. The possibility of new, more efficient generation creates a similar risk. Moreover, during a new unit's 30- or 40-year useful life, entirely new technologies could displace or undercut existing technologies, making an investment less profitable than expected or preventing full recovery of capital costs. New regulatory structures could also change market rules to a merchant supplier's detriment, also reducing the value of the investment. Fuel prices could change in ways that cannot be adequately hedged at reasonable costs, thus affecting market values. Finally, the market structure itself may be inadequate to permit recovery of all invested capital costs through prices that reflect only the marginal cost of the last unit needed to meet demand.

On the other side of the risks/costs/benefits equation, deregulation and generation divestiture meant that regulators and retail customers gave up their ability to direct utilities to build generation. In other words, customers must depend on market forces alone to provide incentives for new generation when, where, and how it is needed. Because utilities no longer own the generation assets, retail customers also relinquish their right to receive electricity at the utility's cost-of-service but instead assume a variety of significant risks. For instance, customers bear the risk that transmission constraints will persist, thus increasing LMPs and UCAP prices. Similarly, if market signals are insufficient to stimulate new generation when demand increases or if suppliers can exercise unchecked market power, customers risk persistently high prices and other costly operational patches to maintain reliability. By accepting market-based prices, customers also leave themselves vulnerable to increasing and volatile fuel prices that drive up LMPs whenever gas-fired units set the price. Finally, an inefficient wholesale market may send the wrong signals, causing investors to prefer peaking units with lower capital costs even though they may not be the most economical or efficient resources to meet Maryland's needs.

Another type of manageable risk is likely to increase costs and reduce benefits under any regulatory scheme chosen. Regulatory instability and uncertainty will almost always exacerbate other risks.[313] Investors will be loath to commit their capital if they are concerned that the basic premises of their investment decisions may change. The regulatory landscape provides the underpinnings for all investments, whether initiated by merchant generators, utilities, or even the State itself. Stability and confidence in the long-term financial arrangements should benefit customers by reducing perceived risk and the cost of capital. On the other hand, if investors suspect that the current regulatory structure is merely the preferred flavor of the month, they will raise the cost of capital to cover possible losses when a new regime wins favor. Long-term generation investments need predictability over the life of the asset, and certainty about the rules for the future will contribute to greater investor confidence and lower capital costs. Thus, to the extent that the State adopts a new direction, it should consider the impact an abrupt change may have and attempt to provide assurances that regulators also recognize the value to customers of an enduring governing structure. This premise implies that policy makers should make changes cautiously and only when the new regulatory configuration has been fully vetted and will not prove to be only a way station pending further experience.

B. <u>Concerns Raised About Deregulation As Currently Configured</u>

With these considerations in mind, the State should evaluate the extent to which customers will benefit by assuming investment risks now borne by merchant generators in return for reducing market risks. The current framework does not serve retail customers well, making them responsible for both high dollar costs (as reflected in utilities' SOS purchases) and high risk costs (the prospect of continuing high prices and potential reliability concerns). Identifying deregulation's failures within the context of risks, costs, and benefits may shed light on alternatives that Maryland may pursue.

First, maintaining the status quo will likely mean that customers will pay increasing LMPs and UCAP prices without new base-load generation or transmission investment. If the State's ambitious demand reduction goals are not fully met and the unwillingness to make new generation commitments continues, persistent transmission constraints into Maryland will at least sustain and possibly exacerbate the recent upward pressure on LMPs and UCAP prices. The State cannot control the approval or timing of proposed new interstate transmission lines that would relieve those constraints. Thus, absent significant changes, customers would likely be captive to higher energy and capacity prices.

Second, the number of suppliers with physical generation resources within the State is limited: two suppliers – Constellation and Mirant – own more than 85% of all generation capacity in the State.[314] Because existing generation owners have a vested

---

[313] *See* Direct Testimony of Jonathan A. Lesser on Behalf of Baltimore Gas and Electric Co., *In the Matter of the Baltimore Gas and Electric Co.'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*, Case No. 9099 (Mar. 30, 2007) at 22:11-23:12.

[314] *See* 2007 PJM Load, Capacity and Transmission Report (July 25, 2007) (*available at* http://www.pjm.com/documents/downloads/reports/2007-pjm-411.pdf.

interest in preserving the high LMPs and UCAP prices relative to the rest of PJM, they have less incentive to build new generation. Moreover, because current generation owners may already control many of the more desirable sites – including expansion opportunities on existing sites – they may be able to discourage new generation by locking in a priority based on PJM's interconnection queue, which dictates the order in which new generation can be interconnected with the transmission grid. Thus, absent structural changes, new suppliers may have difficulty cracking the prevailing concentration of supply ownership in only a few companies.

Third, both potential new suppliers and existing suppliers will be reluctant to invest in new generation so long as the investment environment remains uncertain. The possibility of new transmission lines into Maryland or of a new nuclear plant – either of which, if completed, will substantially lower LMPs and UCAP prices – dampen investment interest in new generation. Moreover, investors who seek longer-term commitments from utilities to support their revenue requirements may be frustrated by the continued existence of potential, if unrealized, retail competition, which makes long-term utility commitments risky because load could move to competitive suppliers if prices fall, leaving utilities with new stranded costs in the form of above-market power contracts.

Fourth, the existing wholesale markets – which are FERC's exclusive domain – have not demonstrated that they will induce new generation investment or produce the lowest customer costs. The flaws and inefficiencies in these markets may require costly steps to maintain reliability and increase both new investment capital costs and energy costs. Despite high LMPs and UCAP prices that are intended to provide strong market signals for new generation, investors remain reluctant to undertake substantial new long-term commitments without an assured revenue source. If they do build new generation, they will try to minimize capital costs to reduce risks and will build peaking units or combined cycle plants – not new base load plants. In addition, the Variable Resource Requirement ("VRR") (*i.e.*, demand curve) in PJM's RPM may actually discourage new generation investment in transmission-constrained zones like SWMAAC. Because the RPM price increases or decreases based on the amount of available capacity in the zone, the addition of new generation will reduce all generators' UCAP payments. This feature has two adverse consequences for retail customers: (1) a high RPM price may not stimulate new generation because investors realize that once those resources come on line, the price will fall; and (2) investors will be motivated to build smaller, lower-cost units that can be completed quickly – *i.e.*, peaking units – in order to take advantage of transient high prices. Finally, failure to mitigate market power effectively may increase LMPs without attracting new generation investment. In sum, the FERC-regulated wholesale energy, capacity, and ancillary services markets do not fully meet Maryland consumers' needs.

C. Option 1: Utility Ownership of In-State Generation Resources and a Return to Cost-of-Service Regulation

A full return to the structure prior to deregulation – *i.e.*, utility ownership of all generation resources in the state with rates based on each utility's cost-of-service – would require utilities to reacquire their previously divested assets or to build new resources sufficient to serve Maryland's load without relying on in-state merchant generators.[315] Such a return to fully regulated electric rates would permit the State to control or direct all aspects of customer service, from generation through transmission and distribution. Virginia is currently returning to full cost-of-service regulation, but can do so because its largest utilities did not divest and still own their generating assets. The cost for Maryland, however, would be very substantial for many years following the reacquisition of generation resources, both in terms of direct costs and assumed risks. Moreover, wholesale markets for generation have evolved significantly, and Maryland's return to the previous state-centric regime could have adverse consequences for PJM's wholesale markets. It would be difficult, therefore, for Maryland to undo entirely the last decade of deregulation efforts. Nevertheless, it is possible for the Commission to direct the State's utilities to build and own some new generation facilities to address load growth, high LMP and capacity prices, and environmental concerns. Such a surgical use of cost-of-service, utility-owned generation may give the State effective control over its energy future while bounding its risks.

1. Possible Approaches for Utilities to Acquire All Required Generation

If Maryland were to re-regulate by requiring its utilities to purchase the generation assets that they divested in 2000, it may have to do so by using the State's condemnation powers, in which case, it would be required to compensate the owners at current fair market value. Maryland has the "inherent" power to condemn privately owned property, so long as the taking "be for public use and that just compensation be paid." *City of Baltimore Dvlpt. Corp. v. Carmel Realty Associates, et al.*, 910 A.2d 406, 415-416 (Md. 2006), citing *Matthews v. Maryland-National Capital Park and Planning Commission,* 792 A.2d 288, 297 (Md. 2002) and *Utilities, Inc. of Md. v. Washington Suburban Sanitary Commission*, 763 A.2d 129, 133 (2000)).[316] "Public use" does not require that

---

315 For purposes of this analysis, we assume that Maryland will continue to participate in PJM and will rely on imports to at least the same extent that it did before divestiture. Thus, Maryland's utilities would still be required to meet a portion of their energy and capacity needs though contracts with or other purchases from out-of-state merchant generators, and the price under those wholesale contracts would continue to be governed by PJM markets. Maryland derives a number of benefits from participation in the PJM power pool, including lower capacity requirements to meet reliability standards than would be the case if Maryland were treated as an electric island. As the Commission has observed, "[e]xisting in-state generating capacity would have to be increased by over 4000 MW to bring load and electric supply into balance if Maryland was forced to rely on in-state resources alone." 2007 Adequacy Report, January 2007, at 2. Our analysis of Option 1 does not contemplate in-state utility ownership of this additional generation.

316 Electric utilities' may also condemn property for public purposes, but that right is tied to the requirement for a certificate of public convenience and necessity. MD. CODE ANN., PUB. UTIL.

the public actually use the condemned property, but requires only that the condemned property serve a "public purpose," which is defined broadly. *Kelo v. City of New London*, 545 U.S. 469, 480 (2005). The Maryland Constitution requires that just compensation be "agreed upon between the parties, or awarded by a Jury." MD. CONSTITUTION, Art. III § 40. Just compensation would undoubtedly be based on fair market value, (MD. CODE ANN., REAL PROPERTY § 12-105(b)), and would be determined as of the date the taking occurs. *Id.* § 12-103. Fair market value would be based, at least in part, on the expected stream of earnings for the plants' remaining operating lives.[317] Such a discounted cash flow analysis will produce a substantially increased value compared to the original 2000 divestiture price.[318] The recently estimated fair market value of the generation assets located in the Maryland portion of the Pepco service territory and now owned by Mirant – 4671 MW – is $6.3 billion to $7.9 billion,[319] which is a reasonable estimate for the amount that Pepco would have to pay to purchase those assets now. If Maryland's utilities repurchase their previously divested assets, the reacquired facilities will be added to the utilities' rate bases at their increased price – regardless of the original divestiture price – and will be subject to a new depreciation schedule.

Alternatively, the State could instruct utilities to build new generation resources that will at least duplicate and thereby displace the existing, previously divested facilities. Construction of new plants would enable the state to improve generation efficiency and reduce environmental impacts by using newer, cleaner technologies. At the same time, however, a fleet of new facilities may be significantly more expensive than purchasing existing facilities, many of which have much shorter useful lives and, therefore, lower values on a discounted cash flow basis.

COS. § 7-207(b)(2) (2007); *see County Commissioners of Frederick County v. Schrodel*, 577 A.2d 39, 47 (Md. 1990) (citing repealed Art. 78 54A, which contained the same requirements as § 7-207), *Bouton v. The Potomac Edison Co.*, 418 A.2d 1168, 1169 (Md. 1980) (same). It is unclear how this requirement would apply when condemnation is of existing generation facilities rather than to build new facilities.

317 *See* Direct Testimony and Exhibits of John O. Sillin on Behalf of the Staff of the Public Service Commission of Maryland, *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan*, Case No. 9099 (Mar. 30, 2007) at 23:10-12 ("[t]he price that investors are willing to pay for [coal-fired] facilities [recently sold in PJM and elsewhere] reflects not their age or their book value, but the returns they believe can be earned on these plants from future operations").

318 The original 2000 divestiture price for all Maryland's utilities was more than $3.8 billion in 2000 dollars, using the depreciated book value for the assets transferred to affiliates or the auction price for those assets sold to non-affiliates. If these assets' value increased only at the overall rate of inflation since 2000, the value in 2007 dollars would be more than $4.6 billion.

319 Task 3 Final Report at [[__]]; *see* Direct Testimony and Exhibits of Timo Partanen and Daniel J. Hughes on Behalf of the Staff of the Public Service Commission of Maryland, *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan*, Case No. 9099 (Mar. 30, 2007) ("Partanen/Hughes Test.") at 5:3-11 (estimating the market value of BGE's divested generating plants at $4.3 billion based on the assessed value of those assets in connection with the Constellation Energy and Florida Power & Light proposed merger)

Moreover, in order to achieve fuel diversity and to assure at least the current level of reliability, utilities would need to purchase a mix of technologies, including peaking, intermediate, and base load units that produce power from natural gas, oil, coal, nuclear, and renewable sources. Some of those technologies may be particularly expensive – or even prohibitively expensive – to meet all current requirements. The construction would also have to be staged over many years, with a nuclear unit requiring ten years or more lead time. The utilities may also be required to find new sites for generation that may be less desirable than existing generation sites (*e.g.*, inferior access to fuel, transmission, and cooling water), and local opposition may make condemnation procedures to obtain those sites difficult and expensive. Finally, if utilities were to build all new power plants to supplant the existing merchant generation resources, it would effectively make many of those older units superfluous, perhaps forcing their owners to cease operations entirely. At best, existing generating facilities would have to be mothballed, but at worst, they would all become no more than scrap, effectively dissipating their considerable remaining value as generating units.[320]

If utilities were to acquire all the in-state generation that they needed to serve Maryland's customers, they would be required to incur substantial debt and issue additional equity. None of the utilities has sufficient current equity to buy or build such a substantial amount of generation. Consequently, their debt/equity ratios would change dramatically, with a much greater debt load. Rating agencies would likely consider the increase in fixed charges (debt interest and equity dividends) relative to revenues as an adverse change and could reduce utilities' bond ratings, making debt more expensive. This could further inflate expected costs for reacquiring generation. The State may be able to bolster the utilities' ability to obtain financing at a reasonable cost, however, by providing guarantees, issuing bonds, or granting direct subsidies, but those measures will have their own set of costs and risks.

2. Impact of Recovering Generation Costs Under Cost-of-Service Regulation

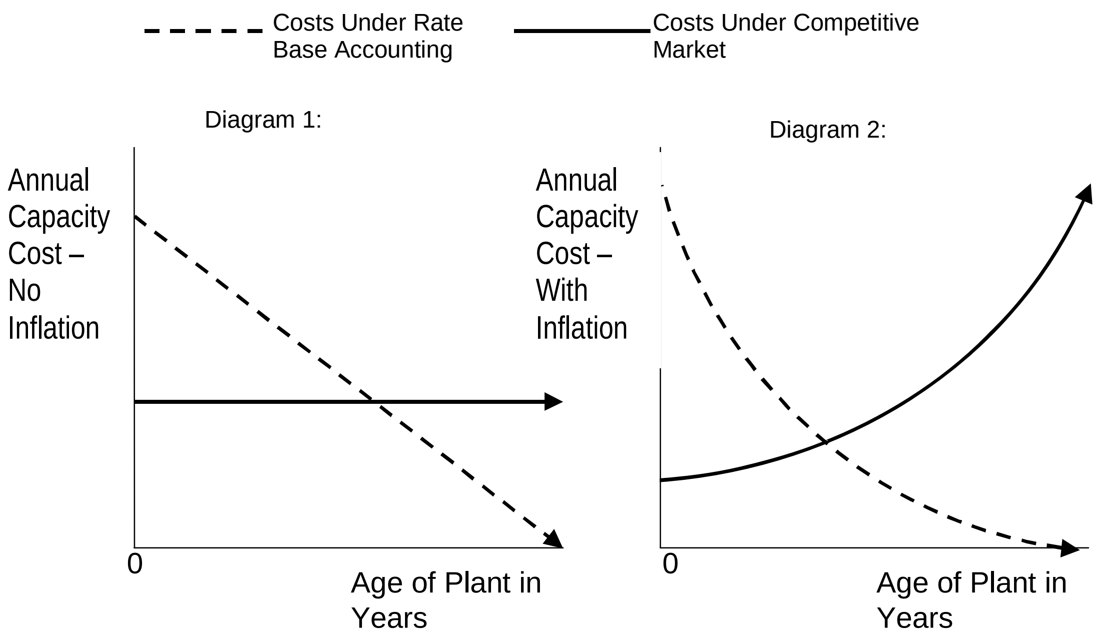
In theory, after adjusting for risk and taxes, the net present value of the cost for new generation plants should be the same regardless of whether the utility owns the plant or contracts for its output. In either case, customers must pay the full capital costs of the unit spread over its useful life. The pattern of cost recovery, however, is vastly different for the two options. The following diagrams illustrate the annual capacity component of rates associated with a new generating plant.[321]

---

320 Some existing plants are "grandfathered" so that they do not have to meet current environmental requirements. Thus, new units will incur higher costs because they must meet current requirements, and those costs will be reflected in higher customer rates.

321 For purposes of a utility's cost recovery, it is immaterial whether it built new generation or simply reacquired its previously divested assets. The pattern of cost recovery will be the same, but a repurchased unit will be depreciated only for its remaining useful life.

Capital Recovery in Normal Competitive Markets Is End Loaded, But Under Utility Rate Base Accounting, Capital Recovery Is Front Loaded



In each diagram, the dashed line shows the pattern of capacity-related rates that the Commission would establish under conventional rate-base regulation, while the solid line shows the capacity-related charges that a merchant generator would require in a competitive market – *i.e.*, if the utility contracted for power from a merchant supplier. Diagram 1 shows the annual capacity-related costs in real terms, excluding the effects of inflation. Under rate-base accounting, the utility's rates reflect its straight-line depreciation of a fixed annual amount charged to customers, but because the utility calculates its return on the undepreciated portion of the asset's original cost, total charges decline steadily until the utility recovers all of its costs. Rates are highest when the utility acquires the plant, and they decline over the plant's life.

In contrast, a merchant generator expects levelized recovery in real dollars – *i.e.*, in a competitive market, a merchant unit expects to receive an annual price set by the cost of new entry, which (absent technological change) will remain constant in real terms. After accounting for inflation, Diagram 2 shows that a merchant investor recovers most of its investment at the end of the plant's life. Both diagrams assume no technological change and a constant degree of scarcity – *i.e.*, that the relationship between demand and supply remains stable. A critical difference occurs if electricity demand grows faster than supply. In that case, competitive market rates would increase to reflect the scarcity, but conventional rate-base rates would remain the same.

Thus, if the State requires utilities to buy or build generation to supply their needs, as they did before deregulation, customers' rates under the traditional cost-of-service regime would immediately reflect the full amount of the utilities' new investments in the rate base. In the initial years following a utility's reacquisition of generation assets, customers would pay rates substantially above a competitive market price. In subsequent years, those rates would decline to a point below a competitive price, and customers would be protected consistently from the risk that scarcity could drive market prices substantially higher than simple cost recovery. At the same time, such strict cost-of-service rates would shield customers from price signals that they should use less because electricity has become scarcer.

Maryland might pursue a different paradigm from traditional regulatory schemes, however, and seek to give utilities incentives for more cost-effective performance. For example, by using price caps or a sliding scale for profit-sharing, the State may more accurately align utility and customer interests.[322] Incentives could be used to motivate the utility (1) to control generation construction and operations costs, (2) to allocate the risk of unexpected costs among utility shareholders, customers, state taxpayers, and third-party stakeholders, (3) to achieve reductions in wholesale market prices, or (4) to control environmental impacts. Under any regulatory approach, however, utilities would be entitled to at least an opportunity to recover all of their prudent investments in generation plus a reasonable return.

In addition to protection from higher scarcity prices, utility ownership of all generation resources would give the State greater control over when, where, and how new resources will be developed. By directing utilities, the Commission could ensure that new generation comports with the State's reliability and environmental objectives. In most instances, however, the State could accomplish the same goals through long-term contracts. As discussed in Section IV.D. below, power purchase arrangements can be tailored to ensure that new generation fits within the State's overall energy plans, and structured procurement procedures can intensify competition among suppliers to obtain the lowest cost.

Importantly, however, if utilities own the entire generation fleet, customers will assume all investment risk. These risks – epitomized in the 1980s and 1990s by huge costs for utility-owned nuclear power plants that sometimes performed poorly and, because of less-than-projected load growth, were no longer deemed used and useful – precipitated the original wave of deregulation because customers would no longer tolerate that cost exposure. If Maryland returns to full regulation, customers will again be responsible for the entire cost of building and operating generating facilities. Customers' only check on utility performance and efficiency will be the "prudence" test – *i.e.*, whether utility management acted reasonably, in good faith, under the same circumstances, and at the relevant point in time – a low hurdle that has not always proved

[322] *See, e.g.*, P. Joskow and R. Schmalensee, *Incentive Regulation for Electric Utilities*, 4 Yale J. on Reg. 1-49 (1986).

effective in stimulating superior effort.[323] To obtain performance comparable to recent merchant plant achievements, the Commission would need to enhance its monitoring capabilities to review utility management closely and to disallow "imprudent" costs.[324]

Finally, utility ownership of all generation assets – whether the Commission directs utilities to build new facilities or to purchase existing units – may require significant modifications to current affiliate relationships. Depending on the outcome of the proposed MidAmerican acquisition of Constellation, if a utility like BGE owns generation, it could be a competitor with its generation affiliate. Its interests would be conflicting and incompatible because the utility will be required to use its own resources whenever possible to benefit customers, even when that preference harms the affiliate. BGE would effectively have an incentive to fail as a generator owner/operator because doing so would assist its affiliate. While it might be possible to amend the Commission's Code of Conduct regulations to provide greater specificity and separation, the Commission would need to exercise extremely close supervision to prevent abuse. Rather than policing these inherently antagonistic affiliate roles, the State may need to require the utility to sever relationships with its generating affiliates entirely to create completely separate companies.

3. Utility Ownership of Only New In-State Generation Resources and Recovery Under Cost-of-Service Regulation

Rather than embarking on a full return to the pre-2000 regulatory structure for all generation resources, the Commission might consider requiring utilities to construct, own, and operate only those new generation resources that are incrementally necessary to optimize the State's cost, reliability, or environmental objectives. Instead of comprehensively procuring more than 11,000 MW of diversified generation capacity sufficient to serve all of Maryland's customers, utilities could be directed to build only those new generators that markets have been insufficient to stimulate and merchant investors have been unwilling to supply. Compared with complete re-regulation, this approach can bound ratepayers' risks while offering the prospect of lower energy and capacity costs, ensuring generation when and where it is needed for reliability, and promoting cleaner generation technologies.

This venture into re-regulation provides many of the same advantages ascribed below to Option 2 (long-term utility contracts for new generation capacity and energy) but gives the Commission and the State's utilities more immediate control of outcomes.

323 Nevertheless, utilities and investors may perceive a greater threat of a prudence disallowance and may, therefore, require a higher rate of return on any new technology that may be subject to an after-the-fact prudence inquiry.

324 Because they have had no generation responsibility for nearly a decade, Maryland's utility management may also be ill equipped to assume control over a large fleet of existing or new generation. Operators, maintenance crafts, and managers have all migrated to the current generation owners, and may not come back to the utilities if ownership changes. The utilities will almost certainly require a significant transition period to assume generation ownership, and customers will necessarily assume the costs and risks associated with that shift.

Direct ratepayer costs may be very similar, whether the Commission instructs utilities to build their own generators or to contract with merchant investors for those same resources. In either case, financing will be less expensive than for a purely merchant project because the utility can recover all prudently incurred costs through rates, and customers will pay the utility's weighted cost of capital. Both ownership and long-term contracts can be structured so that ratepayers reap the benefits that accrue from the new generation's lower energy and capacity charges, and both approaches will also have essentially the same effect on PJM's wholesale markets.

The two approaches differ primarily in the risks that utilities – and, therefore, their ratepayers – assume. As we noted for utility ownership of all generation, if utilities own new generation, they will be responsible for the plants' construction and operation, areas that have been outside their purview since deregulation. The Commission's only check on inefficient management that increases ratepayer costs will be a prudence inquiry, with all of its inherent limitations. If the Commission instructs utilities to contract for generation resources, however, the merchant investor bears the performance risk. Moreover, unlike medium- or long-term contracts that have a fixed length, a utility owner assumes the risk of technology change or economic obsolescence for the entire life of the unit.

As a corollary to the assumption of risk, however, the Commission will have somewhat greater control over when, where, and how new generation is built if it instructs utilities to build rather than soliciting proposals for a wide range of competing projects, none of which may provide precisely the combination of benefits that the State needs. Direct utility ownership will largely avoid such problems because the Commission can instruct the utility to procure exactly the kind of unit the State wants.

Nevertheless, some drawbacks to utility ownership will likely remain. Most notably, the Commission will need to take a more active role in supervising the utilities. Because they are concerned about post-hoc prudence investigations, utilities will probably seek Commission approval before making significant decisions, potentially creating costly inefficiencies that ratepayers must absorb. As with the complete utility ownership option, the Commission will also have to police the relationship between the utility and its generating affiliate. While even a long-term contract for generation raises some concern about intra-corporate abuse, actual utility ownership will exacerbate the opportunities for improper communications and actions. As with all the possible options, the Commission will need to weigh the risks, costs, and benefits before adopting a particular course.

D. Option 2: Utility-Directed Long-Term Contracts

By requiring utilities to enter long-term contracts for new, in-state generation, the State can achieve several key objectives. ***First***, it can control the timing, location, type, and environmental impact of new generation resources so that they mesh with the State's overall objectives. ***Second***, the State can reduce the cost of investment risk by backing new investments with assurances of payment through rates, thus lowering capital costs.

Third, the State can hedge the cost of market risks – *e.g.*, that scarcity or congestion will drive up energy and capacity prices – by diversifying and assuring supply options. ***Finally***, the State may be able to use utility-based contracts to encourage new suppliers in Maryland, thereby enhancing competition and reducing prices in the larger wholesale market.[325]

Strategic long-term contracts for needed new capacity give the State flexibility to add specific kinds of generation – peaker, intermediate, or base load – when and where it is needed without relying on an unpredictable market. The most serious deficiency in the existing regulatory structure has been its inability to assure new generation entry. As we described above, PJM's deficient wholesale markets may encourage existing generation owners to maintain the status quo, exacerbate the risks for investments in new intermediate or base load units, and reward persistent capacity shortages. Continued reliance on these markets threatens higher prices and jeopardizes reliability, but the State may compensate for these flawed markets with strategic utility contracts that are designed to reduce LMPs and UCAP prices, improve reliability, and achieve environmental objectives. Connecticut successfully took steps along these lines, first issuing an RFP for new generation construction and requiring Connecticut's utilities to enter long-term capacity contracts with the winning bidders, and then requiring the utilities to enter long-term electricity contracts with the winning bidders.

The State could also require its utilities to build new generation, rather than simply enter long-term contracts for new generation. In addition to the benefits of long-term contracts, requiring utilities to build new generation would allow the State to retain all the residual benefits of direct ownership. Because these new plants' rates would be based on utilities' somewhat lower cost of capital, ratepayers could receive modestly greater rewards, through lower rates. Ratepayers would also incur greater risks, however, because the State would have to guarantee the utilities' prudent construction costs, as well as their reasonable operating costs.

1. <u>Structure of Long-term Contracts</u>

In developing a strategy for utility-based agreements, the State will need to define the product that will be purchased in intermediate- to long-term contracts. Some states (*e.g.*, Connecticut) have chosen to separate capacity from energy and to purchase only capacity in long-term contracts. Unbundled procurement of capacity only might be justified because long-term energy contracts could require customers to pay too much for risks related to energy price volatility. It may be preferable, however, for customers to maximize the value of their long-term contracts by locking in both the generator's capacity and an option to purchase its energy output at a market price whenever it is

[325] The Commission has already taken a step in this direction. Faced with the prospect that the TrAIL line might not be in service by 2011, the Commission directed the regulated utilities to consider procuring resources that meet the requirements of PJM's Emergency Load Response Program for the power planning years 2011-2016. Gap RFP Order at 7. The regulated utilities must submit their proposed Requests for Proposals to the Commission Staff by December 1, 2008, and Staff must submit the Requests for Proposals to the Commission by December 31, 2008. *Id.* at 7-8.

advantageous to do so. The following structure illustrates a contract form that may be used for combined cycle or peaking units and could be adapted for base load or renewable units.

Pricing Structure. For long-term generation contracts covering the sale of capacity, energy, and related ancillary services, the buyer's payments typically consist of a firm capacity payment, a fixed operations and maintenance ("O&M") payment (generally indexed to inflation), and energy payments. Energy payments include the cost of fuel and variable O&M. The generator is paid for capacity that meets contractual availability standards, as confirmed through periodic capacity tests. The capacity price might consist of a firm component that remains constant throughout the term, a firm escalated component, and/or a component tied to an inflation index. Payments are generally based on a defined price per kW-month of demonstrated capacity, subject to an availability factor and substantial penalty to ensure that the plant remains in good working order. Exceeding an agreed threshold availability factor may warrant an incentive payment as well.

For generation projects that rely primarily on natural gas, the contract energy price typically consists of a transparent fuel price index multiplied by a guaranteed heat rate, plus a variable O&M component, typically indexed to inflation. In light of the inherent uncertainty and volatility of premium fossil fuel prices over the long term, it is neither practical nor sensible to attempt to fix the price of energy or the amount of energy over a ten- or 20-year term. While gas futures are now highly standardized through NYMEX and are liquid and therefore easily traded, the number of buyers and sellers trading gas futures even ten years in the future is very thin. For this reason, even if a supplier were willing to fix the price of energy to be delivered over the long term, there would be no efficient way to hedge both price and quantity risk. Thus, it would be untenable to require firm, fixed energy pricing over the intermediate term – five to ten years – or long term without contract reopeners or automatic adjustments indexed to the value of delivered fuel. Hence, in structuring long-term contracts, the energy price is customarily tied to a liquid, transparent fuel price index.[326]

The energy sale usually takes the form of a heat rate call option, in which the buyer has the right to the energy output from the plant at a strike price based on the product of the guaranteed heat rate and the fuel price index, plus non-fuel, variable O&M. The buyer "calls" the option and takes delivery when the market energy price equals or exceeds the "strike" price defined by the formula. The call option may be further subject to constraints such as a minimum run time, seasonal heat rate adjustments, and number of starts per year. By exercising the call option when the strike price would warrant dispatch and the unit is available, the buyer avoids cash losses when it is not economic to convert natural gas to electricity. Under the heat rate call option paradigm, the seller retains significant financial incentives to maintain the unit's availability and efficiency in order to maximize any spread between the guaranteed heat rate and actual

[326] For Maryland, an appropriate index for natural gas would be the Transco Zone 6 Non-New York (TZ6-NNY) or TETCO M3. A number of leading indices for oil are also available.

operating heat rate. The buyer retains significant financial incentives to maximize energy output from the plant in relation to the cost of energy in the day-ahead or real-time markets.

Physical versus Financial Delivery. Under some long-term generation contracts, the buyer takes physical possession of the delivered capacity and energy products. This arrangement makes sense when the buyer is a load-serving entity with physical obligations. Many of the objectives of a long-term generation contract can be met, however, without the buyer taking physical delivery of energy, capacity, or ancillary services. While most generators seek an income stream that moves with the market value of energy, some will be willing to forego market-based revenue for a steady stream of income, largely independent of LMPs. A buyer might be seeking to hedge the risk of short-term market fluctuations by purchasing a block of energy and capacity under a stable cost structure and reselling the products in the spot market. Both seller's and buyer's objectives can be satisfied under a financial transaction structure where the buyer pays the contract capacity or reservation payments as well as an energy payment based on a heat rate call option. Under this paradigm, the buyer receives payments equal to the RPM market value of the capacity and the day-ahead market value of the energy purchased by buyer under the call option. If the payments are netted on a daily or monthly basis, the result is a "contract for differences" ("CfD"). Daily or monthly settlement of the CfD may be either positive or negative.

Under a heat rate call option contract (with either financial or physical settlement), there need not be a perfect match between the actual energy output of the generating unit and the quantity of energy called under the option and paid for by buyer. The buyer decides on a daily basis whether to call the option based on a contractual heat rate and fuel price index, which might diverge from the actual plant heat rate and delivered fuel price. If the actual heat rate is better and/or actual fuel costs are lower, the generation owner might bid the unit into PJM at a lower price and produce additional output for its own account. Conversely, if actual performance or fuel cost is less advantageous than the contract strike price, the generator may have a contractual right to provide replacement energy from the grid rather than actually operating the plant on that day. Under such an arrangement, the buyer would be indifferent. Because the CfD is a financial arrangement designed to confer the benefits of a long-term hedge relative to other procurement options, the buyer should not care whether energy is sourced from replacement energy or a specific unit.

New versus Existing Generation. Because of potentially adverse interactions with PJM's existing markets, the State's long-term contracts may need to be limited to new generation. PJM's RPM provides ample compensation to existing capacity resources. As long as an existing resource can rely on the RPM price for locational capacity compensation, it will not contract with the State's utilities for a lower price. Given the inevitable decrease in RPM prices when supply increases, however, new capacity may never find short-term RPM payments sufficient and may require a utility contract before it will commit capital, particularly for intermediate and base load units. Thus, the State may only be able to attract new generation facilities if it assures investors a fixed stream of capacity revenue for at least five or ten years – or even for the life of the unit – that will permit it to recover a large portion of its capital costs that cannot be recovered from sales of energy and ancillary services.

Performance Provisions. Long-term contracts should also ensure that generators will perform as expected, *i.e.*, that they will be available to provide capacity and energy at peak load, when prices are highest and the system is stressed. The capacity contract could be structured so that generators will pay a substantial penalty if they are unavailable when needed most. For instance, if the generator cannot provide energy when the real-time or day-ahead market price exceeds an established strike price, the generator would pay the utility the difference plus an additional penalty. Such a contract structure gives the generator strong incentives to produce energy when it is needed most to maintain system reliability and to moderate price spikes. At the same time, it protects customers from scarcity prices. This penalty structure is similar to the wholesale FCM being implemented in New England.[327]

Procurement Mechanism. Regardless of the product purchased, the State must stimulate vigorous competition to ensure the lowest price and most advantageous terms.[328] If the product cannot be narrowly defined, however, or if substantial flexibility is required to negotiate particularized terms, a clock auction may not be effective. Although innovative new auction forms may be able to accommodate more complex products,[329] the most effective procurement method may be a traditional RFPs and evaluation of sealed bids.

Contract Length. The State should choose a contract length that maximizes value without assuming excessive risk, but the market can define an optimal combination. By permitting investors to propose various contract lengths (as Delaware has done, for instance), the State can discover the minimum commitment required to assure new peaker, intermediate, or base load construction. Nevertheless, it may be desirable to lock in a longer contract term at an advantageous price if the State can control other risks – *e.g.*, technological obsolescence.

---

327 *See* R. Speck and M. Bidwell, "A New England Capacity Market That Works," *Public Utilities Fortnightly* (Aug. 2006) at 19; P. Crampton and S. Stoft, "Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency (Sept. 2007), *available at* http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-forward-reliability-markets.pdf.

328 Each utility could continue to be responsible for supplying its own load through individual contracts. Alternatively, a state-wide procurement may permit the broadest possible competition by aggregating all of the State's load to stimulate maximum competition. The Commission could then allocate the costs equitably among the utilities.

329 New auction forms may permit procurement of both bundled and unbundled energy and capacity in the same auction. Although it has not been proven in U.S. electricity market applications, "combinatorial auctions" may provide greater efficiency and lower procurement prices and could warrant further investigation. *See Combinatorial Auctions* (P. Cramton, Y. Shoham & R. Steinberg eds., MIT Press 2006).

Generation Mix. Finally, to the extent that competitive markets alone do not produce an optimal mix of generation and demand resources, the State can use directed utility contracts to spur needed infrastructure investment. For instance, as in Connecticut, the State could target priority requirements that markets have neglected – *e.g.*, base load, renewable, or DSM resources. Separate procurements could facilitate maximum competition among projects within a focused category or even within a targeted location. Of course, any limitation on competitors is likely to increase the price, but the State may elect to sacrifice the lowest cost in order to achieve other important objectives or to reduce other costs. Long-term utility contracts give the State substantial flexibility to tailor the type and timing of resources that will serve Maryland's overall needs.

2. Risks Related to Long-term Contracts

When utilities enter long-term agreements for generation or demand resources with assurances that those costs will be collected in rates, their customers assume part of the investment risk for those facilities. For instance, by entering a 20-year agreement for a new gas-fired plant, the utility – on behalf of its customers – accepts the risk that over that 20-year span gas-fired technology might be displaced by more efficient, cheaper generation units, that natural gas as a fuel might become too expensive for power generation, or that a successful DSM program will eliminate the need for new generation. In those events, the utility's agreement may no longer have the economic value that the State originally expected, but customers will remain responsible for its costs. For the period of the contract, this is the same investment risk that customers assume if the utility owns the generation resource.

On the other hand, when a utility contracts for long-term capacity, the generator owner retains all of the risks related to the unit's performance, and customers are protected from higher prices attributable to the project's execution or operation. For example, assuming that the resource owner is creditworthy or adequately bonded, customers will be protected from increased construction costs or operational failures that prevent the unit from performing as expected. If the generator does not meet performance criteria, customers may collect damages sufficient to give them the full benefit of their bargain. Of course, customers will always retain a residual risk that the generator will default and be unable to perform or pay damages, but a contractual arrangement insulates customers from most of the performance risk that they would assume if the utility owned the generation facility.

If retail customers enter into long-term contracts for capacity, they will assume market risks. If market prices exceed the contract price, customers will have made a good bargain. On the other hand, it market prices fall below contract prices, customers may regret their agreement to higher prices. By using long-term contracts for only new generation, however, retail customers will have a partial hedge against market fluctuations because a significant portion of their electricity resources – all currently existing generation resources – will still be supplied through the short-term market. Moreover, the contract structure – *e.g.*, a CfD with a call option for energy – can ensure prices that at least match the markets.

Nevertheless, if investment risks materialize and retail choice remains in place so that load migrates from utilities to alternative suppliers, a utility may be left with a long-term, high-cost contract and "stranded" costs that may have to be recovered through higher wires charges. For this reason, if the State requires utilities to enter long-term contracts, it may wish to reevaluate the efficacy of retail choice for residential and small commercial customers. So long as the State requires utilities to offer the lowest-cost default service based on competitive bids, no significant retail competition is likely to develop for any customer class other than large commercial and industrial. A retail supplier's administrative costs related to acquiring residential and smaller commercial customers, plus the cost of power and a reasonable profit, will almost always exceed an SOS price that is based the lowest competitive bids for relatively short-term power commitments. When a portion of the SOS portfolio consists of long-term contracts, however, a falling market price may stimulate more short-term retail competition. Long-term utility contracts are certainly incompatible with retail choice that would permit load to avoid those contract costs by switching to competitive suppliers. If customers retain the right to retail choice, they should pay penalties for switching away from SOS and fees for switching back to SOS sufficient to cover any stranded costs associated with the utility's long-term supply contracts.

3. Impact of Long-term Contracts on Wholesale Markets

Utilities' long-term contracts for new generation capacity are likely to improve competition and lower wholesale market prices. Because only a portion of generation capacity will be under long-term utility contracts, wholesale energy and capacity markets will continue to function and impact Maryland's retail customers' electricity rates. Maryland's contracting strategy can be tailored, however, to have maximum effect on wholesale market prices, thereby extending the benefits for customers.

First, strategic contracts to locate new Maryland generation resources in SWMAAC should lower both LMPs and RPM prices.[330] New, lower-cost generation can displace more expensive generation that currently sets high LMPs during periods of peak usage. By contracting for new units with lower marginal costs, utilities will reduce the expected LMPs for all other generation at that energy price node. Similarly, added supply will push RPM prices down on the VRR demand curve, reducing capacity costs for the entire capacity zone. These lower market prices should be reflected in a lower energy component in competitive bids for short-term SOS contracts.

Second, the State may use new generation contracts to diversify the number of Maryland suppliers and thereby invigorate wholesale competition. As noted, only two owners in Maryland control more than 85% of the in-state generating capacity, and transmission constraints currently limit the level of competition from outside the State.

[330] This is the same strategy that Connecticut used to reduce Federally Mandated Congestion Charges. Although its assumptions may be questionable and have been contested, Connecticut has estimated that long-term contracts for only 787 MW of capacity could reduce such charges by as much as $1 billion. *See* CT DPUC April 2002 Press Release.

Although this review does not include a market power study, these highly concentrated in-state suppliers – coupled with the exemption of some generators from market mitigation – may be able to maintain higher market prices than would prevail if more competitors were able to bid prices down to the lowest marginal cost. Generation affiliates may have a further competitive advantage by virtue of their relationship with utilities. For these reasons, in contracting for new generation, the Commission will need to be particularly vigilant to identify any abuse of affiliate relationships.

In order to mitigate some of the advantage that incumbent owners have, the State may wish to limit bidding for new long-term contracts to owners with less than ten percent of Maryland's supply capacity. To the extent that new competitive suppliers gain a foothold in Maryland, their aggressive bidding will have a mitigating effect on LMPs that will benefit customers. This approach may, however, exclude the most efficient bidders who, because of their access to the most suitable sites, may submit the lowest bids. The State might assist new entrants to this market by streamlining or actively assisting in siting new generation – *e.g.*, through condemnation proceedings and auction of potential sites. In the end, the value of enhanced competition may outweigh the somewhat higher contract costs necessary to ensure new suppliers.

E. <u>Option 3: State Power Authority</u>

The State can exercise maximum control – but will assume maximum risks – if it eliminates all intermediaries and buys, builds, or contracts for generation resources directly through a statutory power authority. This approach may be able to reduce capital costs materially, eliminate some transaction costs, and assure a reliable electric supply that exactly matches the State's priorities. On the other hand, however, a power authority acting on customers' behalf will bear the entire obligation for any adverse outcomes, regardless of whether those consequences were foreseeable or controllable. Thus, while the potential for reduced direct dollar costs may make this option attractive, the level of accepted customer risk would be unprecedented – even more than under traditional cost-of-service regulation. Policy makers should assess whether the possible benefits outweigh the substantial inherent risks. Despite authorization legislation in August 2007, Illinois is still in the early stages of creating a power authority and it is too early to assess the success of Illinois' approach.

A Maryland power authority could be authorized to undertake a wide range of duties, including any combination of the following: (1) analysis of available and prospective resources that will be necessary to meet the State's energy needs (*i.e.*, integrated resource planning, as discussed below in Option 4); (2) aggregation of DSM or energy efficiency resources to permit more effective participation in capacity markets; (3) other promotion of DSM and energy efficiency measures; (4) procurement and/or development of prospective generation sites for resale to generation investors; (5) stimulation of renewable energy projects thorough direct ownership or contracts; (6) contracting for all or part of the capacity or power to meet the State's utilities' loads; and (7) direct ownership of generating facilities to satisfy all or part of the State's utilities' load. The first three items require the State to assume relatively little risk, but a power authority with responsibility for any of the last four items would necessarily accept significant risks on behalf of customers.

A State power authority could provide a clear focal point for developing DSM and energy efficiency resources throughout the State. Rather than relying on multiple agencies and individual utilities, each with its own distinct programs and plans, a power authority could coordinate a state-wide effort to reduce electric demand. It could investigate and adopt the best practices from government or industry, disseminate those methods to customers and utilities, administer the apparatus for paying rebates or other compensation, and measure and report comprehensive, consistent results. Even with tariff provisions that attempt to eliminate any utility reluctance to implement demand reduction steps, a power authority may be more committed to achieving the State's targets and better able to concentrate all programs under a unified management structure whose primary function is to assure success.

A power authority will likely have significant cost advantages over a utility that owns generation resources because it would have materially lower capital costs and would not pay taxes. As a result, a State power authority may be able to undertake renewable or other desirable – but costly – projects that would be uneconomic if pursued in the private sector. At the same time, however, such power authority ownership would shift significant investment and market risks from merchant generators or utilities to electric customers. For instance, the power authority may have to issue bonds or pledge the State's credit to purchase or develop generation sites. If those projects founder before completion or cannot operate successfully, the State's taxpayers or ratepayers must pay.[331] At some level, failures could be sufficiently significant that they affect the State's credit, thus increasing the cost of all the State's borrowing.

Moreover, although a power authority will likely have lower capital costs, it will go through a transition period – seeking to staff requisite positions and develop internal performance guidelines – during which it will likely be less efficient than merchant generators or utilities. While competitive markets starkly expose incompetence, a state power authority can often mask its inefficiencies. Without a profit incentive, the State will need to develop other incentives that will identify economies and drive the power authority to reduce customers' costs. Over time, a power authority may become entrenched in established methodologies and may not be as innovative or adaptive to changing circumstances as in the private sector. Some examples of power authorities that own and operate generation resources have not always demonstrated superior performance to utilities, particularly as generation owners and operators.[332] A newly

---

[331] The Washington Public Power Supply System ("WPPSS") is the most notorious example of a public power authority failure. Created in the 1950s to assure cheap, reliable electric power in the Northwest, WPPSS invested heavily in nuclear power plants, but unforeseen events and poor management combined to produce the largest bond default in U.S. history.

[332] *See* J.E. Kwoka, Jr., *The Comparative Advantage of Public Ownership: Evidence from U.S. Electric Utilities*, 38 Canadian J. of Econ. 622-640 (May 2005) (finding that publicly-owned utilities are less efficient than investor-owned utilities as generation owners).

created State power authority, may also have difficulty hiring experienced staff and building an effective organization from scratch. A power authority's ability to assume immediate ownership and ownership of existing generation assets would be particularly problematic and risky. Finally, the State would need to allocate the benefits that accrue from a power authority equitably across all the State's utilities to avoid disadvantaging any customer segment.

F. Option 4: Integrated Resource Planning

Before deregulation, states traditionally required their vertically integrated utilities to prepare periodic IRPs to project demand and supply requirements for a decade or more into the future. Regulators reviewed and approved these plans as blueprints for identifying necessary generation expansions or retirements, reliability-enhancing and economic transmission upgrades, and desirable demand reduction initiatives. The IRPs let states direct and control the orderly development of the electric system to comply with overall policy objectives. Because utilities had an obligation to serve, the states could require them to build new facilities that contributed to the broad public interest. As part of their steps toward re-regulation, Connecticut, Delaware, Illinois, and New Hampshire have each required some form of IRP.

Since deregulation, the IRP process has largely lapsed in Maryland, as in other similarly situated states. By divesting their generation, utilities relinquished control over generation investment decisions that were thereafter left entirely to merchant generators. By joining RTOs and ceding transmission planning authority to an independent system operator like PJM, utilities further diminished their IRP role – and, by extension, the State's role as well. FERC also eroded state control by asserting its authority over resource adequacy determinations that had been the states' domain.[333] Because states could no longer direct their utilities to build system facilities, their planning capabilities and authority atrophied, although the statutory requirements for IRPs often remained on the books.[334] Consequently, planning for generation, transmission, demand response, and

333 *See, e.g.,* Order Denying Rehearing, *ISO New England Inc.*, 120 FERC ¶ 61,234 (Sept. 14, 2007), *appeal pending*, *Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission*, No. 07-1375 (D.C. Cir.) (asserting that FERC has jurisdiction under the Federal Power Act ("FPA") to set resource adequacy requirements for the states).

334 *See*, *e.g.*, CONN. GEN. STAT. § 16-50r (requiring annual reports containing the following: "(1)[a] tabulation of estimated peak loads, resources and margins for each year; (2) data on energy use and peak loads for the five preceding calendar years; (3) a list of existing generating facilities in service; (4) a list of scheduled generating facilities for which property has been acquired, for which certificates have been issued and for which certificate applications have been filed; (5) a list of planned generating units at plant locations for which property has been acquired, or at plant locations not yet acquired, that will be needed to provide estimated additional electrical requirements, and the location of such facilities; (6) a list of planned transmission lines on which proposed route reviews are being undertaken or for which certificate applications have already been filed; (7) a description of the steps taken to upgrade existing facilities and to eliminate overhead transmission and distribution lines . . . ; and (8) for each private power producer having a facility generating more than one megawatt and from whom the person furnishing the report has purchased electricity during the preceding calendar year, a statement including the name, location,

environmental protection has been fragmented among multiple governmental, quasi-governmental, and private players, with little conscious integration.

Maryland needs integrated energy resource planning to harmonize the sometimes discordant State objectives, and the deregulated marketplace will not produce the coordinated strategy that is a prerequisite for achieving key policy aims. To fill this gap, the State could rejuvenate the dormant planning process, enlarged and augmented to address the challenges ahead.[335] The planning function that had resided with the Commission before deregulation could remain there or could be assumed by a state power authority or planning board. As in the past, the state planning authority should rely on the utilities in the first instance to prepare long-term forecasts of peak load, consumption, demand response, energy efficiency, and transmission improvements. This information will need to be augmented with forecasts from PJM for expected transmission and generation resources that will impact Maryland. Finally, this renewed IRP process can incorporate all State and federal environmental requirements and targets so that they will mesh with load, transmission, and generation projections. The result should be a comprehensive, unified roadmap for the State that lets each component of the electric system contribute to achieving defined policy aspirations.

In order to function effectively, the planning process must include authority to modify and direct those elements of the plan that the State can control. For example, an IRP process will only realize its potential value if the State can instruct utilities to build or contract for specific new generation in accordance with the plan. The IRP will likely be ineffectual if it must rely for implementation on the vagaries of a flawed market. The IRP should also have teeth to assure utility and government agency action to effectuate identified demand response, energy efficiency, and renewable resource initiatives. A paper IRP with no mechanism for implementation is unlikely to succeed.

G. Option 5: Aggressive Efforts to Shape PJM's Wholesale Markets

Regardless of any re-regulation option adopted for Maryland, PJM's wholesale markets will play a disproportionate role in the State's electric supply. Before deregulation, the Commission could influence the price that its electric customers paid for power by helping to select the composition of the utility's generation fleet and, therefore, the elements of its generation cost-of-service. As early as 1978, however, the federal regulatory framework began to intrude on states' abilities to manage their own energy costs. PURPA required utilities to purchase power from qualified facilities at the

---

size and type of generating facility, the fuel consumed by the facility and the by-product of the consumption").

[335] Maryland statutes currently require some components of an IRP. *See* MD. CODE ANN., PUB. UTIL. COS. §§ 2-118 (requiring public service companies "to formulate and, after approval by the Commission, to implement long-range plans to provide regulated service"); 7-201 (requiring the Commission Chairman to prepare annual ten-year plans identifying possible sites for construction of electric plants within the State and to include utilities' current and projected efforts "to moderate overall electric generation demand and peak demand").

utilities' avoided costs, adding high-cost generation to the utilities' portfolios, regardless of need. EPACT 1992 and FERC Order Nos. 888 and 889 opened the door for wholesale suppliers who were unaffiliated with the vertically integrated utilities to supply power through the utility's grid. FERC's Order No. 2000[336] placed planning, control, and operation of the transmission grid in the hands of an independent system operator, further diluting the states' responsibilities. Based on all of these developments, PJM created a variety of locational markets for energy and capacity – *e.g.*, LMPs and RPM – that now dominate utilities' wholesale purchases and the pass-through price that retail customers must pay. Even a return to vertically integrated utilities and full cost-of-service regulation will still require dependence on these PJM markets for power imports and to assure reliability. Thus, the Commission will never be able to moderate retail prices effectively without influencing the mechanisms for setting wholesale market prices to ensure that they produce the lowest competitive price for customers. Connecticut has begun intervening aggressively in FERC proceedings to protect its ratepayers from unreasonable wholesale rates.

PJM's current market structures may not achieve that end. ***First***, although PJM has required transmission owners to build new infrastructure that would relieve constraints into Maryland and reduce LMP and UCAP prices, FERC has approved "incentive" rates that permit transmission owners to collect returns on equity that are 50 or 100 basis points above their normal returns, and Congress has authorized National Interest Electric Transmission Corridors,[337] key new transmission lines now remain only plans, with no assurance when they will be completed. ***Second***, wholesale markets in Maryland may not be sufficiently competitive to protect retail customers from high rates. PJM's Market Monitor has raised concerns about the possibility of non-competitive markets that may not have been adequately mitigated to protect consumers from the abuse of market power.[338] Because Maryland's SOS prices merely reflect costs from the underlying markets,[339] they will only be as reasonable and competitive as those markets, which FERC – not the states – regulates. Consequently, Maryland may have no recourse by which it can challenge excessive SOS prices without first contesting the underlying wholesale markets. ***Third***, PJM markets have not stimulated new generation resources in Maryland. As described above, structural problems with the capacity and energy markets, among other factors, may actually discourage new generation investment.[340]

[336] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999).

[337] *See* Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat., 594, 941 (2005) § 1221.

[338] *See* Statement of Joseph E. Bowring in Response to the Federal Energy Regulatory Commission's Order of May 18, 2007, *Allegheny Elec. Coop. Inc., et al. v. PJM Interconnection, LLC*, Docket Nos. EL07-56-000 and EL07-58-000 (June 12, 2007) at 2.

[339] For instance, the Price Anomaly Threshold used as a check to ensure that SOS bids are reasonable is derived primarily from market prices. Thus, any non-competitive distortions in the wholesale markets will be translated into the same non-competitive distortions in the SOS bids.

[340] *See supra* at 10-13, 18-19.

Under the FPA, FERC has exclusive jurisdiction to make any required changes in wholesale markets, but states can impact those federal decisions in significant ways. States like Connecticut have aggressively challenged market structures and rules and have achieved modifications that reduce wholesale prices.[341] Since the November 30, 2007 Interim Report, the Commission has taken aggressive action in three key areas. First, the Commission initiated a complaint at FERC to eliminate blanket exemptions from bid caps for some generators that permitted them to exercise market power and thereby to increase prices in the energy market. These exemptions cost Maryland ratepayers as much as $80 million annually. FERC agreed with the Commission that such exemptions were unjust and unreasonable and required all generators to be subject to bid caps if they have an ability to exercise market power. Second, FERC initiated a separate proceeding to examine the methodology that PJM uses to determine when generators have an ability to exercise market power. While most suppliers advocated more lenient criteria, the Commission – joined by other states – strongly urged FERC to maintain its existing stringent test for market power. Third, the Commission led a broad coalition of capacity buyers in a comprehensive complaint at FERC seeking to reverse the outcome of the RPM transition auctions and seeking $12 billion in PJM-wide reductions in capacity payments through May 2011. Although FERC initially dismissed the complaint, the Commission has requested rehearing. These are major initiatives seeking greater equity and fairness in wholesale markets regulated by FERC.

The Commission has also acted jointly with the Organization of PJM States, Inc. ("OPSI") to marshal the aggregate influence of the 14 PJM states on wholesale market issues that affect them. FERC approved a scope of responsibility for OPSI's that includes (1) collecting information, (2) monitoring markets and events, (3) considering PJM-related proposals affecting reliability, facility siting, and electricity prices, and (4) submitting proposals to improve PJM markets.[342] PJM acknowledged, however, that OPSI "could evolve into a regional layer of coordinated governance over a discrete scope of electricity issues."[343] OPSI's initial authorized funding through PJM is modest – $425,000 a year – and annual increases are limited to 15% unless FERC approves more,[344] but in-kind contributions from the member states could expand OPSI's capabilities to become a firm advocate for the states' interests in the face of possible encroachment in areas that affect their regulatory responsibilities.

While forceful participation in the federal arena to protect Maryland's interest is not a complete substitute for more direct re-regulation alternatives, other available options may prove inadequate to address critical needs if the Commission neglects

[341] Some states have provided statutory authorization for their public service commissions to retain counsel and experts to assist them in representation before FERC or federal courts. *See*, *e.g.*, Conn. Gen. Stat. § 16-6a(b); La. Admin. Code tit. 45, § 856; Ark. Code § 23-4-102.

[342] Order on Funding Mechanism for Organization of PJM States, Inc., *PJM Interconnection, L.L.C.*, 113 FERC ¶ 61, 292 (2005) at P 4.

[343] *Id.* at P 5.

[344] *Id.* at P 7.

opportunities to shape PJM's wholesale markets. FERC may not be the most desirable forum for resolving issues that affect Maryland's electricity reliability and prices. Given recent federal and regional developments, however, it (or federal courts) may be the only place where Maryland can obtain meaningful relief.

V. Conclusion

Electric industry restructuring has not achieved many of the lofty objectives that heralded its implementation in half the U.S. states. As a consequence, several states have reconsidered the wisdom of their initial deregulation initiatives and have partially and tentatively reintroduced some components of traditional cost-of-service rate regulation, *e.g.*, integrated resource planning, utility responsibility for procuring new generation, or state power authorities. Most of those efforts are still too new to evaluate definitively, but they suggest the need for targeted state actions to supplement or displace wholesale electricity markets that have not produced – and may never produce on their own – the expected lower prices and assured reliability.

Each re-regulation option entails direct costs, risk costs, and benefits that Maryland should weigh in charting its energy future. A full return to pre-2000 cost-of-service utility regulation would impose very substantial direct costs and risks on ratepayers but would protect them from volatile market price swings. Utility contracting for new generation to meet pressing reliability and environmental needs can reduce wholesale energy and capacity charges across the board while delimiting ratepayers' risk. A new state power authority with a mandate to construct new generation would assume greater State risk in return for reducing some financing and transaction costs, but may also sacrifice competitive market efficiencies. Integrated resource planning poses few ratepayer risks but may be ineffective without a mechanism that will assure implementation. Finally, developments in wholesale power markets will affect Maryland's energy alternatives, and the Commission may have no choice but to participate aggressively in the federal proceedings that shape those markets.