APPENDIX I
STATE RESPONSES TO DEREGULATION PROBLEMS
ADOPTED BY APRIL 30, 2007

State	Precipitating Events	Responses Adopted to Date
California	Tripling of energy prices in late 2000 where rate caps removed; blackouts in 2000-2001; bankruptcy of major utility, near bankruptcy of other major utility. More recently – growing public awareness of global warming dangers.	Eliminated retail choice, at least through 2013 when last of state purchases of supply for customers expires State took on responsibility to purchase supply on long term at time of market meltdown. Authorized state agency to purchase power for all non-shoppers during the crisis (AB1X – Statutes of 2000). ▪ Retail rates were capped during the crisis, but customers were required to pay the unfunded costs in future rates – i.e. a deferral. Authorized long-term procurement of power by utilities. ▪ Under AB 57, September 24, 2002, the utilities gained back their right (and obligation) to purchase power for non-shopping customers as of no later than January 1, 2003. ▪ Under the Act, the Commission opened proceedings to fulfill the statute's purposes: o …assures creation of a diversified procurement portfolio, assures just and reasonable electricity rates, provides certainty to the electrical corporation in order to enhance its financial stability and creditworthiness, and eliminates the need, with certain exceptions, for after-the-fact reasonableness reviews of an electrical corporation's prospective electricity procurement performed consistent with an approved procurement plan. Section 1(c). ▪ D.04-01-050 adopted the first long-term procurement framework. ▪ In April 2004, the California Public Utilities Commission opened a new procurement rulemaking, R.04-04-003, to serve as an "umbrella" proceeding to coordinate and incorporate Commission efforts in separate proceedings on community choice aggregation, demand response, distributed generation, energy

		efficiency, qualifying facilities, renewable portfolio standards, and transmission assessment and planning. ▪ As part of R.04-04-003, the Commission in D.04-12-048 gave the utilities authority to plan for and procure resources for the planning period 2005 through 2014, in concert with policies articulated in the resource adequacy phase of the proceeding. o Utilities should not rely on the spot market for more than 5% of their net shortterm needs. o In January 2004, the CPUC adopted a 15-17% reserve margin for all Load Serving Entities. In October 2004, the CPUC accelerated the planning reserve margin requirement to June 1, 2006. o In December 2004, the CPUC adopted a more open and competitive procurement process, under which utilities would solicit offers for long-term contracts and projects. o The CPUC made it clear it supports a hybrid market structure, consisting of a mix of utility-owned generation and power purchase agreements. o Governor supports the loading order for new resources adopted by the CPUC, which provides environmental preferences for new resources, the acceleration of the 15-17% resource adequacy requirement two years from 2008 to 2006, open and competitive solicitation procurement processes, and wants the CPUC to encourage utilities to sign long-term contracts to ensure new resources are built, per Commissioner Diane Gruenich. http://www.cpuc.ca.gov/static/aboutcpuc/commissioners/03grueneich/04speeches/050414_epsa_final.pdf Provided secure cost recovery for certain capital additions and upgrades to baseload plant. ▪ The PUC, in Decision 05-02-052, on February 24, 2005 approved the proposal of Pacific Gas & Electric for pre-approval of up to $706 million in expenditures to replace the steam generator at the Diablo Canyon nuclear power plant. Expenditures above that amount are to be subject to a prudence review. The Commission retained its authority to change the ratemaking treatment.

		Utility bought merchant power plant built by struggling non-utility generator. ▪ Sempra acquired Calpine's new Otay Mesa plant. http://intelligencepress.com/features/top_power/last_week.emb. The PUC approved the proposal in June 2006, Docket R.01-10-024. Statewide public power authority empowered to build plants. ▪ On May 16, 2001, Governor Gray Davis signed Senate Bill 6X creating the California Consumer Power and Conservation Financing Authority. The California Power Authority has broad powers to construct, own, and operate electric power facilities, and finance energy conservation projects. The CPA's mission statement can be found at http://www.documents.dgs.ca.gov/CPA/CPA_MissionStatement.pdf ▪ But see the Governor's 2004-5 budget, which proposed to eliminate the Authority, as it had constructed no new plants since its creation. http://www.lao.ca.gov/analysis_2004/resources/res_15_8665_anl04.htm ▪ The Governor's 2006-7 budget proposal recited that the "purpose of the California Consumer Power and Conservation Financing Authority (CPA) was to assure a reliable supply of power to Californians at just and reasonable rates, including planning for prudent energy reserves. The CPA was also created to encourage energy efficiency, conservation, and the use of renewable resources. The CPA was authorized to issue up to $5 billion in revenue bonds to finance these activities. After two and a half years, it was apparent that the CPA was providing minimal value in assisting the state in meeting its energy objectives. Consequently, ongoing activities have been transferred to other state organizations pending a reorganization of the state's energy related functions." http://www.ebudget.ca.gov/StateAgencyBudgets/8000/8665/mission_statement.html While it has not been eliminated, the CCPFA role has been less prominent that originally envisioned. Funding for the CCPFA was eliminated in SB 1113 (Chesbro) Chapter 208, the 2004-2005 budget. No additional funding has been proposed in the Governor's budgets.
Connecticut	Current debate was spurred by 22% increase in 2006 at end of	Legislature, Attorney General and Governor have made proposals to deal with recent increases. None have passed into law as yet.

	transitional standard offer cap, followed by 7.7% increase in January 2007, for customers of largest electric utility (CL&P, an NU subsidiary). UI customers are receiving phased-in increases totaling 44.7%. Rates now the highest in continental U.S. (19 cents/kWh for CL&P, 22 cents/kWh for UI). In 2005, legislation passed in response to anticipated federally-mandated congestion costs to be charged by regional transmission organization, ISO-NE. Also, the state faces a potential capacity shortfall by 2010.	Earlier, in response to reliability crisis regarding Connecticut as major load pocket in New England, and associated locational charges anticipated from ISO-NE, the stated passed PA 05-1, 2005 June Special Session. This Act allows CL&P and UI to re-enter the generation business under limited circumstances. Specifically, this act required the DPUC to conduct a request for proposals (RFP) for measures that could reduce federally-mandated congestion costs by February 1, 2006, and allows it to conduct subsequent RFPs. The proposals can be for a wide variety of resources, including power plants, small-scale distributed generation, and conservation initiatives. The utilities can submit bids, subject to several restrictions. DPUC can approve a total of no more than 250 megawatts of electric-company-owned generation statewide under the initial and any subsequent RFPs (a power plant is typically twice this size). The act's underlying rationale was that the state needed to act to reduce federally-mandated congestion costs. The rationale for this particular provision was that non-utility power plant developers have been unable or unwilling to build sufficient generating capacity, particularly in the southwestern third of the state, to offset the congestion. The DPUC on April 23, 2007 announced the selection of three generation proposals totaling 782 mW, and one energy efficiency proposal for 5 mW. http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/0da262db6da4f243852572c6006a91b3/$FILE/4.23.07%2005-07-14PH02%20pressrelease.doc In 2003, the original caps on standard offer service rates were removed, allowing rates to move back up to rates in effect in 1996. A transitional standard offer was put in place, with a fuel adjustment provision.
DC	The District deregulated its	No action specifically related to re-regulation has been adopted. The PSC has

	sole electric utility, Pepco, in 2000. Rates were gradually reduced by 7 percent and then capped through February 2005, when they expired. Residents then saw a 17 to 18 percent increase in their bills, according to the District Public Service Commission. SOS power is bought on laddered one- and multi-year contracts -- a system that kept down rate hikes over the last two years since a rate freeze ended. Since the end of the freeze, standard offer service rates have increased: 17.7% (residential) and 24% (small commercial) increases February 2005. 12% (residential) and 10% (small commercial) as of June 1, 2006.	approved a pilot advanced metering project.
Delaware	Anticipated 50%, 67% and 118% rate increases in May 2006 for DP&L residential, commercial and industrial customers, respectively, as transition rate caps came off.	HR 6 (2006) • Rate hike phase-in option for smaller consumers: o 5/1/2006 - 15% o 1/1/2007 - 25% o 6/1/2007- 19% o 1/1/2008- True-up/Balance • RFP for new in-state supply to be issued

		o w/PSC and Energy Office OK o Evaluation and selection by PSC, Energy Office, Controller General, Office of Management & Budget o Delmarva RFP bids under consideration now • Utilities to do Integrated Resource Plan o 10 year horizons o Review by PSC, Controller General, Office of Management & Budget • **Utilities obliged to supply *Standard Offer Service* (SOS) to non-shoppers** o "safe, efficient, adequate and reliable" o Consistent with IRP o At least 30% from wholesale market o "Returning Customers" pay based on wholesale spot market • **To serve SOS customers, utilities may** o (1) enter into short- and long-term contracts o (2) own and operate generating plants o (3) build generation and transmission facilities o (4) make investments in Demand-Side resources, and o (5) take any other Commission-approved action to diversify their retail load. • **PSC may restrict shopping access if in public interest** • **Demand side management promoted** o DEC to continue DSM activities o PSC may order DP&L to develop and implement Demand-Side Management programs o to reduce overall electricity consumption and/or o to reduce usage by customers during peak periods ▪ E.g. time of use rates, advanced metering infrastructure, central air-conditioning and hot water heating cycling off and on programs, interruptible rates, etc. • Advance metering docket opened at PSC to study **SJR 3 - Presumption in favor of return to regulation** **SB 74 – Renewable Portfolio Standard**

		• PSC to implement RPS for all retail electricity sales in the state
		  o *except* sales to any industrial customer with a peak demand in excess of 1,500 kilowatts.
		  o Percentage increases annually
		  o From 1% in 2007 to 10% in 2019
		  o PSC has some flexibility in out years
		  o Solar and fuel cells favored, wind also
		  o Credits may be bought and traded when PJM sets up GATS
		
		SB 281 - Energy Efficiency Financial Incentives Act of 2006.
		• Appropriates $8.0 million for energy efficiency programs
		• Run through Dept of Natural Resources and Environmental Control
		• DNR/EC to explore statewide “Efficiency Utility”
		• Like VEU in Vermont, NYSERDA in NY
		
		SB 280 – Low Income Bill Assistance
		• Supplemental general fund appropriation to Delaware Energy Assistance Program
		• $2 million dollars
		• Secretary of Health and Human Services to report on continuing needs for DEAP
		
		Proceedings are underway to implement these statutory provisions.

Illinois	Under a 1997 state law, electric rates were frozen through the end of 2006. In 2006, it was forecast that retail rates of Commonwealth Edison (ComEd) and Ameren would skyrocket in 2007. The ICC staff forecast an increase of 24% for ComEd residential customers if supply for them	Legislators have made proposals to deal with recent increases. None have passed into law as yet. The Illinois Commerce Commission took separate actions approving rate phase-in plans for Commonwealth Edison Company and the Ameren Illinois Utilities on December 20, 2006, Docket Nos. 06-0411, 06-0779, 06-0780, and 06-0781. Both plans were voluntary, and consisted of caps and deferrals with reduced interest, as well as “voluntary” contributions by the utilities to low-income/senior assistance, and in the Ameren case, to environmental and efficiency efforts as well (since withdrawn – see chart on proposals). The proposals were later withdrawn, in light of legislative

	were purchased using the auction method, proposed by the utility. The forecast rate increase would go even higher if ComEd's then-pending distribution rate increase were approved in whole or in part. The rate freeze originally was set to expire at the end of 2004 but the legislature extended it for another two years because, at that time, no competition had developed for residential consumers. Rate increases averaging 22 percent for Commonwealth Edison customers and increases of 55 percent for Downstate electrical customers of Ameren Corp. took effect Jan. 1. Ameren also eliminated a discounted rate for space heat customers, and those customers saw even higher rate increases, some up to 170%.	efforts to impose rate freezes. See Appendix II on Additional Proposed Responses for more current information.
Maine	FERC decision approving installed capacity market and transition costs in New England.	SOS was procured by the PUC under all requirements contracts; laddered: 1/3 procured annually for 3 year term. *Report on Standard Offer Procurement for Residential and Small Commercial Customers*, Docket No. 2004-147 (Aug. 3, 2004). An Act to Enhance Maine's Energy Independence and Security (Acts of 2005

		Chapter 677), 35-A M.R.S.A. §§ 3210-C, 3210-D amended the approach, providing for longer-term contracts. The Order provisionally adopting proposed rule can be accessed at the MPUC website, reference Docket No. 2006-557, January 2, 2007: http://www.state.me.us/mpuc/doing_business/rules/proposed/index.htm The Statute as understood by the PUC provides: 1) PUC to consider efficiency explicitly, per bid process; 2) goal is to obtain "over a reasonable time period the lowest price for standard-offer service to residential and small commercial customers…" and may use various contract lengths and terms to achieve this goal. 3) PUC may negotiate long term capacity contracts (with a priority given for renewable resources) and order the distribution utilities to sign and recover the costs of such contracts through distribution rates, in order to "develop new capacity resources to reduce demand or increase capacity so as to mitigate the effects of any regional or federal capacity resource mandates." Subsection A contains general authority language from the Act (35-A M.R.S.A. § 3210-C(3)) that states that contracted resources may not exceed the amount necessary to ensure the reliability of the grid or lower customer costs. Solicitations may take place every 3 years if warranted per purposes of statute. 4) January 2007 PUC rule states purpose of statute is not to restore monopoly regulation; rather PUC emphasized the statute's limited purpose to lower ISO-imposed capacity costs. Capacity may be resold into market, used to supply SOS or Maine consumers generally, or otherwise disposed of per Order of PUC. Utilities to recover full costs of administering contract, including impact on cost of capital. 5) A Report and Plan would be produced at least every two years and would contain: an assessment of bulk level grid reliability, an identification of the amount, type and location of necessary generation, transmission and demand-side resources, and Commission action or recommended legislation to facilitate the development or

		maintenance of necessary infrastructure. The Report and Plan would identify the State's capacity resource and transmission needs over a future time horizon and the type of resources (e.g., installed capacity, localized operating reserves, renewable capacity, demand-side resources) to meet the needs. The Report and Plan would also include the steps that can be taken to implement the plan, including use of the long-term contracting authority under the Act, requiring utilities to construct or facilitate the development of necessary infrastructure, and Commission participation in proceedings of other agencies as a resource for information on the need for capacity and transmission resources. Finally, the provisional rule requires the Commission to seek public input in the development of the Plan and requires T&D utilities to submit reports on service territory bulk level reliability. 6) PUC on October 20, 2006 issued an RFP for Standard Offer Service for the residential and small commercial customers of that State's two largest electric utilities that solicits bids for one, three, six, and nine year contracts for both energy and bundled DSM services. In orders dated January 9, 2007 (see, e.g. *Standard Offer Bidding Process for Residential and Small Business Customers,* ME PUC Docket No. 2005-591 and *Central Maine Power Company Request for Approval of Request for Bids Pursuant to Chapter 307 And Associated Waivers*, Docket No. 2006-585, Order Designating Standard Offer Provider and Directing Utility to Enter Entitlements Agreement, January 9, 2007), the Commission accepted bids for one-third of the residential SOS load for a three-year period. Services under accepted bids began March 1, 2007. In the CMP case, the Commission ordered: "we designate FPL Energy Power Marketing (FPL) as a standard offer provider for the residential and small non-residential class in the Central Maine Power Company (CMP) service territory. FPL is designated to provide standard offer service to one-third of the load for a three-year period beginning March 1, 2007. The resulting overall price for standard offer service for the one-year period beginning March 1, 2007 will be $0.087961 per kilowatt-hour. The FPL standard offer bid [about 9 cents/kWh] was

		linked to its bid to purchase certain of CMP's non-divested entitlements to energy and capacity [at about 7 cents/kWh]. CMP is directed to sell these entitlements to FPL for a three-year period beginning March 1, 2007, as specified in the FPL linked bid." 7) For large customers, the PUC continued the 6-month cycle of procurements. On February 1 (Order embargoed until February 13), the PUC designated the SOS suppliers under the RFP as follows: "Through this Order, we designate Constellation Energy Commodity Group Maine, LLC (Constellation) as the standard offer provider for 100% of the large non-residential classes in the Central Maine Power Company (CMP) and the Bangor Hydro-Electric Company (BHE) service territories. We designate FPL Energy Power Marketing, Inc. (FPL) as the standard offer provider for 60% and Dominion Retail, Inc. (Dominion) as the standard offer provider for 40% of the medium non-residential class in the CMP service territory. We designate FPL as the standard offer provider for 100% of the medium non-residential class in the BHE service territory. All designations are for six month periods, beginning March 1, 2007. The average blended prices for standard offer service for this period will be 8.720¢/kWh for the medium class and 9.255¢/kWh for the large class in the CMP service territory, and 8.827¢/kWh for the medium class and 10.320¢/kWh for the large class in the BHE service territory." *Standard Offer Bidding Procedure forCMP and BHE Medium and Large Non-Residential Customers,* Order Designating Standard Offer Providers, ME PUC Docket 2007-21.
Maryland	A sudden 72 percent increase in early 2006 for BGE customers, and an increase of over 38% for PEPCo customers (suburban DC).	In March 2006, the Maryland PSC Ordered BGE to Phase-In Residential Market-Based Rates: • Move to residential market-based rates could increase bills 40-81% • PSC adopts a rate-increase mitigation plan to ease transition • Rate increases initially would be limited to 21% and then increase gradually • BGE would recover under-collections over a 15-month period

	Under deregulation that took effect in 2000, Maryland cut the rates that utilities could charge for electricity generation by 7 percent and capped them for a period of four to six years. In 2004, caps for Pepco and Delmarva expired. Caps for BGE residential customers were scheduled to expire in July 2006. Also, major electric utility proposed merger with Florida Power & Light, raising concerns about control by out-of-state firm and sharing of benefits of merger with Maryland.	• Carrying costs would be calculated using a 5.0% interest rate • Deferral is default option, but customers can opt out to avoid carrying costs. On April 21, 2007, Maryland PSC approved Pepco-Delmarva Rate Increase Phase-In Plan as filed • Approved settlement just in time to allow plan implementation by 6/1/06 • Residentials can opt-in to plan for 3-step one-year phase-in of SOS hikes • Phase-in starts at 15% hike, another 15.7% on 3/1/07; then full rate 6/1/07 • Without the phase-in, increase will be 39% for Pepco, 35% for Delmarva • Deferred costs recovered over 18-months after 6/1/07 without interest • Settlement acknowledges companies' distribution rate caps end 12/31/06 April 28, 2007, PSC okayed and modified BGE's Amended Rate Increase Phase-In Plan • Both new and old plans start phasing-in increases on July 1, 2006 • Amended plan phases-in increases for participating customers over 18 months • Lengthens overall phase-in and payback period to nearly 3 years from 2 years • Carrying costs on deferrals set at zero, changes "opt-out" default to "opt-in" • PSC affirms prudence and recoverability of costs and fairness of bidding • BGE asks for rehearing of PSC's zero interest on deferrals ruling On June 15, 2006 Maryland General Assembly passed "veto-proof" bill caps BGE rates, then offered phase-in, dismissed PSC: • Bill capped BGE July 1 rate increase at 15% for 11 months • Rate options between 6/1/07 and 1/1/08: market or phased in prices • BGE can collect interest expense on deferred amounts • All customers to get initial 15% hike, must pay deferrals plus interest • Bill "fired" commissioners 7/1/06, provisions limit PSC's challenge ability • Gov. to appoint new PSC chair and commissioners from Assembly slate • Bill passed with sufficient margins to override veto. Chair of Commission sued in state court to defend his position, and court held that legislature had not used proper

		procedure to reform commission. After change of party in control with November 2006 elections, and various efforts to force resignation, Chairman resigned late January 2007. The new Commission has held a number of hearings on how to address the ongoing crisis of high electricity bills.
Massachusetts	Rates have gone up gradually and significantly over last several years.	No action has been taken to alter Massachusetts' restructuring scheme in several years. NStar (Boston Edison) got approval in 2005 for a rate stabilization plan, under which a distribution revenue increase was smoothed by further deferral of Transition (Stranded) Costs, with interest. http://www.capelightcompact.org/pdfs/05-85FinalSettlementOrder.pdf In that Settlement, NStar also agreed to adopt a laddered procurement process for its default service, under which 50% of load would be procured under 1-year contracts, 25% under 2-year contracts, and 50% under 3-year contracts.
Michigan	Pressure of gradually increasing energy prices, desire for more in-state generation, and forecasts of generation needs by 2010.	Full retail open access electric customer choice) for all customers of Michigan investor-owned electric utilities took effect on January 1, 2002, pursuant to PA 141. The Commission continues to support the statute and the goal of competition. See, 2006 Annual Report on the Status of Competition to the Michigan legislature. However, unlike other states that have deregulated generation, Michigan utilities were not required nor encouraged to divest their generation. In the PSC's September 11, 2003 and January 30, 2007 orders in Case No. U-13698, the Commission acknowledged that retail competition has yet to take hold in areas served by cooperatives. Under Section 10x of Act 141, the Commission deferred full-fledged choice programs for residential and small commercial member-consumers until such time as retail markets developed and Alternative Energy Suppliers expressed interest in serving those loads. In 2006, the Commission eliminated the distribution rate subsidy previously given to customers of Detroit Edison and Consumers Power who had chosen an Alternative Energy Supplier. Case Nos. U-14399 and U-14347

		On August 31, 2006, in Case No. U-14838, the Commission approved a settlement agreement that reduced Detroit Edison's electric rates for residential and business customers by $78.75 million. In this order, an experimental Choice Incentive Mechanism (CIM) and experimental load aggregation program for large commercial and industrial customers were approved. The experimental CIM mechanism is designed to help ensure electric rates remain reasonable even if electric choice sales volumes change dramatically from those assumed in rates. The CIM mechanism allows increases or decreases in rates as choice customers switch electric loads between bundled and choice services. The load aggregation pilot program will allow the aggregation of individual customer loads from separate locations for billing purposes, and is expected to help determine if this type of aggregation program will benefit customers in the long run. See, 2006 Annual Report on the Status of Competition to the Michigan legislature, at 12-13. In response to complaints filed in Case No. U-13808, the Commission ordered Detroit Edison to convene a collaborative process to resolve issues involved in electric choice metering. The settlement agreement resulting from the collaborative on metering and amended electric choice tariffs was approved in Case No. U-14838. The tariff changes provide for an optional, less costly, alternative to interval metering for small volume choice customers. The optional method will allow standard load profiling for non-interval metered customers to determine hourly usage for billing purposes. *Id.* at 13. Meanwhile, one major utility has been voluntarily divesting itself of certain generation holdings. On November 21, 2006, Consumers Energy sold its interests in the 1,500 MW Midland Cogeneration Venture to GSO Capital Partners and Rockland Capital Energy Investments. On July 11, 2006, Consumers Energy announced its plan to sell its 798 MW Palisades nuclear power plant to Entergy Nuclear Palisades, LLC, for $380 million. An October 24, 2006 order in Case No. U-15098 extended the 2007 deadline for

		choice customers to give notice of their intention to return to full utility service. The return-to-service provisions previously established in rate cases continue to require choice customers to commit to taking either unbundled or full service from the utility by the deadline (usually December 1) in advance of the summer peak season.
Montana	50% rate increases for largest utility between start of deregulation in 1998 (and sale by Montana Power of all its generating plants) and beginning of 2006. http://www.helenair.com/articles/2006/01/08/montana_top/a01010806_02.txt	On April 20, 2007, the Legislature passed HB 25 which would allow Montana Power to build plants, with pre-approval by PSC, subject to stricter emissions requirements. The governor let the legislative session adjourn without signing or vetoing the bill, ten days have passed since the bill went to the Governor, and thus the bill has become law. The governor may bring the legislature back for a special session to address his issues with HB 25. As passed, the bill now includes the following provisions: • The PSC cannot approve a proposed plant for coverage in retail utility rates until the final air quality permit is in place and the public has had a chance to review it • The PSC cannot approve a proposed coal-fired plant unless the state or federal government enacts a law requiring carbon sequestration or the plant will capture and sequester at least half of its CO_2 • Gas-fired plants must mitigate a portion of their CO_2 emissions through carbon offsets or emissions credits • Flexibility for NorthWestern Energy to purchase enough firm power for periods when wind generation is unavailable
New Hampshire	California/West Coast crisis of 2000-2001	For smaller utilities, default service to be provided via competitive solicitation. For largest utility, PSNH, settlements of restructuring litigation resulted in legislative approval of proposal whereby default service (then called transition service) would be provided out of PSNH's own plants, and purchases from the wholesale market. PSNH is allowed to recover its "actual, prudent and reasonable costs." RSA 369B-3, IV(b)(1)(A). *See also* Order No. 24,714, issued December 15, 2006. In its original restructuring legislation, the Legislature had promoted the sale of all of PSNH's generation assets, except those needed for voltage support in remote areas. After the crisis in California markets, reconsidered this requirement, and delayed the date as of which the Commission could require the fossil and hydro generators until no earlier than April 30, 2006. 369-B:3a:

		http://www.gencourt.state.nh.us/rsa/html/XXXIV/369-B/369-B-3-a.htm After this date, the Commission could authorize, although not require, PSNH to divest its remaining generation assets, "if the commission finds that it is in the economic interest of retail customers of PSNH to do so." *Id.* The Commission has not required any further divestiture. On April 13, 2006, the Commission denied a request to change the name of default service to "basic energy service" and instead ordered that such service be called "energy service." Order No. 24,614. Integrated Resource Planning was required by legislation that had not been repealed as a part of restructuring. However, utilities in practice had been granted regular waivers during the initial period of restructuring. PSNH filed a LCIRP filed April 30, 2004, pursuant to RSA 378:38, together with a request for a waiver of significant portions of the filing requirement. The Commission issued Order No. 24,435 (February 25, 2005), denying the request from PSNH for a waiver, and discussing the role of the LCIRP in a restructured environment. Following settlement talks, three parties (PSNH, OCA and Staff) agreed to defer review of the Revised LCIRP and instead focus on reaching consensus on the filing requirements for the next LCIRP, expected to be filed 2007. The proposed settlement included, among other things, the following: (a) planning horizons no shorter than the longer of 5 years or the single longest lead time of resource options considered, (b) PSNH to include in its next LCIRP information that shows 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, and to discuss the potential variability in this resource balance over the planning period using scenario analysis, (c) In the event the Commission determines that new generation should be included

		in the supply-assessment, PSNH would identify all reasonably available resource options to meet the projected resource balance over the planning period. The methods used to evaluate the cost-effectiveness of such resource options would also be described including identification of the costs and benefits, (d) To the extent that such methods include a comparison of the costs of implementation for a specific resource and the wholesale market energy and capacity costs avoided over the life of the resource, PSNH will present the wholesale price forecast, identify the forecast components and specify the input assumptions used in their development, e) PSNH would include a description of its then current coal procurement strategy and discuss any recent changes to that strategy that are designed to improve the reliability and/or reduce the cost of its coal supply over the planning period, including an account of PSNH's efforts to reduce its coal transportation costs, (f) PSNH agreed to discuss the impact of anticipated changes in regulations on the characteristics of fuel it plans to purchase and the impact those procurement changes are expected to have on the cost of generation from fossil-fired facilities, (g) PSNH would present a forecast of the cost of coal-fired generation over the planning period, (h) PSNH agreed to explain how it takes into account the price of SO2 allowances when procuring fossil fuels, (i) PSNH agreed to describe its strategy to hedge the cost of supplemental power purchases on a daily and annual basis, (j) PSNH would discuss and evaluate the costs and benefits of all reasonably available alternatives (including scrubbers) to its existing strategy for meeting existing or anticipated new SO2 regulations, and PSNH would describe its SO2

		compliance plan and quantify its impact on retail rates, (k) PSNH would explain how New Hampshire's NOx budget program works and specify the magnitude and timing of the required NOx reductions, and describe its NOx compliance plan and quantify its impact on retail rates, (l) PSNH would identify all reasonably achievable production adaptations, market-based mechanisms or other alternatives that could be used to comply with Phases I and II of New Hampshire's Clean Power Act or proposed regional or federal programs to decrease power sector CO2 emissions such as the Regional Greenhouse Gas Initiative, and provide an economic assessment of production adaptations and market-based mechanisms and quantify the potential rate impact of any compliance plan, (m) PSNH would discuss and evaluate alternatives for complying with potential state and federal mercury emissions regulations, (n) In the event the Commission determined that the demand-side resource assessment should include an analysis of the cost effectiveness of non-Core Energy Efficiency Programs (i.e., energy efficiency programs not funded through the System Benefits Charge authorized by RSA 374-F:3, VI), PSNH would describe the process for integrating demand-side and supply-side resources in a manner that meets current and future needs at the lowest reasonable cost to customers. In its order approving the settlement with minor changes, the Commission noted as follows concerning future generation construction by PSNH: "Although the construction or acquisition of new generation capacity by PSNH appears to require prior legislative authorization, information on the costs of such supply-side alternatives provides a valuable context for planning. We therefore find it appropriate for PSNH to include generic cost information regarding the construction or acquisition of new generation capacity in its next LCIRP. We will not require PSNH to evaluate new generation options that hold out little likelihood of satisfying customers'

		energy service needs at the lowest overall cost. However, to the extent that PSNH suggests or advocates a change in the law that would allow it to build or acquire new generation, PSNH must demonstrate that the resources that it plans to add to its portfolio will satisfy customers' energy service needs at the lowest overall cost." Order No. 24,695 at 24-25. http://www.puc.state.nh.us/Regulatory/Orders/2006orders/24695e.pdf
New Jersey	Rates have been going up in recent years, despite the use of laddered three-year procurements for supply for non-shopping customers. In the results of the most recent procurement announced in February, 2007, the Board of Public Utilities awarded contracts that, when folded in with the results of the previous two years' auctions, will produce increases for residential customer ranging from 10-14%. http://www.bpu.state.nj.us/home/news.shtml?46-06	In October, 2006, the Governor launched a statewide multi-stakeholder process, led by the Board of Public Utilities, to develop an Energy Master Plan for New Jersey. http://nj.gov/emp/about State law requires the development of an EMP every 10 years. According to the web site, the EMP has four goals: **Goal 1: Secure, Safe, and Reasonably Priced Energy Supplies and Services –** To provide safe, secure, reasonably priced energy supplies and services to New Jersey's commercial, industrial, transportation, and residential customers, while reducing dependence on traditional fossil fuels and fossil fuel generation, decreasing electric and natural gas transmission congestion, utilizing efficiency and renewable resources to supplement the State's energy resources, proactively planning for in-state electricity generation retirements, and reducing the demand for energy. **Goal 2: Economic Growth and Development –** To encourage and maintain economic growth prospects for the State by recognizing and fostering the multiple functions of energy in the economy—as an integral part of producing and transporting goods and services; as a means of attracting business to the state with reliable, reasonably-priced energy; and as a potential driver of new areas of economic activity. **Goal 3: Environmental Protection and Impact –** To promote the achievement of Federal and State environmental requirements and objectives in an effective and low-cost manner and, where possible, provide market-based incentives to achieve those goals. These policies should be coordinated with the State's environment, economic, and redevelopment plans to protect and enhance environmental quality, conserve natural resources, and improve the quality of life in New Jersey. In the interest of promoting a more secure, economic, and environmentally

		responsible energy future, the state policy makers have a single, over-arching goal for New Jersey as it completes the Energy Master Plan: **Main Goal: Reduce projected energy use by 20% by 2020 and meet 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.** http://nj.gov/emp/about/goals.html
New York		Power/Switch proposals by utilities approved, to provide short-term discounts as incentives for customers to try alternative suppliers. Public power authority contracting for plant construction. Long Island Power Authority in 2002 and 2003 entered into long-term output contracts, to support the building of power plants. http://dis.puc.state.oh.us/DISOCR.nsf/0/4185E6BB4F4DACA885257115005BED87/$FILE/MW6JSE2%23J6JV0$B4.txt February 16, 2006 letter to public commenter. Public power building plants to relieve congestion emergency. In 2001, the New York State Power Authority built 10 small combined cycle generators in New York City to relieve a capacity emergency. Public power purchasing low-cost power and redistributing it. Power Authority of the State of New York has for many years had long term contracts with Hydro-Quebec for low-cost hydro power. It makes this power available for economic development. http://www.nypa.gov/about/history1.htm Shortly after Governor Spitzer took office, the office within the PSC responsible for promoting electric markets was disbanded.
Ohio	Inability of competitive suppliers to meet price to beat of incumbent utilities, and need to keep price increases from being too sharp and	Since 2004, Ohio has run some auctions to see if competitive suppliers can beat the utility's price and take over providing supplier of last resort services. In the first auction, for Cleveland Electric Illuminating service for the years 2006-2008, none of the 7 bidders could beat the utility's price (which did not include the charges for paying off CEI's stranded costs). In the second, in March 2006, no bidders made any

	volatile.	offers to serve First Edison's service area, and the auction was canceled. Rates for non-shopping customers of First Energy are frozen through 2008, except for some fees. According to the PUCO Annual Report for 2006: "The PUCO worked with Ohio's electric distribution companies to develop rate stabilization plans (RSPs) to prevent customers from experiencing the "sticker shock" of going to market rates after the market development period for electric choice ended on Dec. 31, 2005. "The RSPs went into effect for Ohio's electric distribution utilities on Jan. 1, 2006. Through the efforts of the PUCO, Ohio's electric customers were spared the prospect of much higher electric rates and will instead experience gradual increases over the course of the next several years. "On Jan. 4, 2006, the PUCO approved a rate certainty plan (RCP) proposed by FirstEnergy. The RCP will serve as an alternative to the company seeking approval of adjustments for generation-related expenses. The PUCO adopted the RCP to stabilize potentially volatile price changes over the next three years. "The PUCO's decisions to institute the RSP for the Dayton Power and Light Company (DP&L), FirstEnergy, American Electric Power (AEP-Ohio) and Duke Energy (formerly Cincinnati Gas & Electric), was challenged by the Ohio Consumers' Counsel and other parties. By law, all challenges to PUCO decisions are heard by the Ohio Supreme Court. "In May 2006, the Supreme Court issued a decision in the FirstEnergy appeal. In its decision, the Court found that the PUCO had appropriately approved many aspects of FirstEnergy's RSP. The Court did, however, find that the RSP established by FirstEnergy and the PUCO did not provide an alternative means for customer participation in choosing an electric supplier. The Court found that the PUCO did not allow for proper customer participation when it rejected the results of the December 2004 auction and accepted the rates in FirstEnergy's RSP. The Court found that the plan did not establish a competitive bidding process as required by law, and determined that another competitive option must be developed. "In July 2006, the Court reached a similar conclusion regarding AEP-Ohio's RSP. "The PUCO subsequently directed FirstEnergy and AEP-Ohio to submit plans for another competitive retail electric service option. In both instances, the RSPs will

		remain in effect. "FirstEnergy submitted its proposal to establish a competitive service option on Sept. 29, 2006. ...Under the proposed plan, competitive suppliers would be able to specify the number of megawatts of electricity they are willing to provide at a particular price. Customers who choose to accept the offer will have their generation service switched to the competitive provider. "AEP-Ohio submitted its proposal for a competitive option on Sept. 22, 2006. ...Under AEP-Ohio's proposal, customers will be able to select from a range of generation and price options. Customers will be able to choose at what price-level they would be willing to participate in the program. For instance, a customer could choose to participate in the program only if the program results in a discounted price. If the auction results in a higher generation rate, those customers will not be enrolled in the program. However, if a customer chose to participate in the program at a rate that was 5 percent higher than the rate offered through AEP-Ohio's RSP, and the auction resulted in a price at or lower than the 5 percent premium, the customer would be enrolled in the program AEP-Ohio also proposed. "A green power option is available for customers to choose. "After the competitive bid, customers who did not choose to participate in the program initially will be given an opportunity to participate at generation rates determined by the competitive bidding process. "Constellation NewEnergy, Inc. appealed the PUCO's decision to implement a RSP for DP&L. In December 2004, the Court issued a decision that upheld the PUCO's order."... "The Dayton Power & Light Company's (DP&L) rate stabilization plan requires the company to fund a voluntary enrollment program in which customers opt-in with a group whose electric load is then offered up for bid to competitive suppliers. More than 50,000 customers chose to participate in the program in 2006. "If competitive suppliers can beat DP&L's rate, the customers enrolled in the program will be switched to the competitive supplier. If the supplier offers cannot beat DP&L's rate, the customers will continue to be served by DP&L. To date, several auctions have been held, but none of the bids could guarantee DP&L customers a cost savings. Additional bids will be conducted during 2007."

		http://www.puco.ohio.gov/PUCO/MediaRoom/AnnualPublications.cfm?id=7224 The Commission on June 14, 2005 directed Monongahela Power to discuss potential terms and conditions of a transaction through which Monongahela Power would transfer its Ohio service territory to AEP's subsidiary Columbus Southern Power. Monongahela had refused to propose a rate stabilization plan. In August, Monongahela and AEP announced they had reached agreement on the purchase by AEP of the Monongahela utility. AEP has been allowed to secure recovery of certain pre-construction baseload plant improvement costs. ▪ On March 18, 2005, AEP filed an application with the PUCO for authority to recover costs associated with the construction and ultimate operation of an integrated gasification combined cycle electric generating facility (docket number 05-0376-EL-LNC). ▪ In April 2006, the PUCO granted AEP-Ohio's request to recover pre-construction costs, estimated to be $23.7 million, of the IGCC facility. The recovery will be achieved through a by-passable generation surcharge applied to AEP-Ohio's standard service rate approved in the company's rate stabilization plan. The IGCC-related revenues collected through the surcharge will be tracked to reduce additional generation increases the company may request through its rate stabilization plan. ▪ The Ohio Consumers' Counsel, Industrial Energy Users-Ohio, Ohio Energy Group and FirstEnergy Solutions, Inc., have filed appeals to the PUCO decision with the Ohio Supreme Court.
Oregon	California and Western Markets energy crisis.	The state's electricity restructuring law passed in 1999. Large customers were first able to choose market alternatives in March 2002, and began service with alternative suppliers in January 2004. The law also required the PUC to report to the Legislature by Jan. 1, 2003, on whether residential consumers would benefit from buying power from competing suppliers at market prices. On December 12, 2002, the PUC issued a report stating that residential consumers

		would not benefit at that time from a choice of competing power suppliers. Since March 2002, residential customers had a menu of new rate options provided by PGE and PacifiCorp that provided more choices without the risks of a competitive power market. In addition to Basic Service, there are three renewable resource options and at least one option that can reduce energy bills for customers who cut back on electricity use during high-cost times. http://www.oregon.gov/PUC/news/2002/2002_036.shtml The Commission formalized rules that accepted the status of small customers as "cost of service" customers in 2002. http://apps.puc.state.or.us/orders/2002ords/02-702.pdf In November, 2002, the Oregon Public Utility Commission took steps to jump start Oregon's competitive retail market. In response to a request made by Industrial Customers of Northwest Utilities (ICNU), the Commission approved a five-year plan that allowed large commercial industrial customers of Portland General Electric to pay a fixed transition charge if they decide to have their energy provided by an Electric Energy Supplier (ESS) or a daily pricing option from Portland General Electric. The change is only available to customers whose average hourly demand is one megawatt or greater. Oregon's 1999 Electric Industry Restructuring law gave the Public Utility Commission the responsibility to ensure costs are not shifted from one set of customers to another. Large customers had to decide by November 8, 2002 to choose the five-year option. Customers who select the five-year option give up receiving the standard cost-of-service rate for at least five years. However, with a two-year notice, a customer can switch to any PGE option available to new customers for service after 2007. http://www.oregon.gov/PUC/news/2002/2002_031.shtml In the fall of 2000, the Commission adopted the Division 038 Direct Access Rules to govern the anticipated markets. Unless waived, OAR 860-038-0080(1)(b) (the "Market Price Rule") prevents utilities from including new generating resources in rate base, and instead requires that they include new generation in revenue requirement at market price, and not at cost. The rules required the utilities to file a Resource Plan that would lead the utilities to divest or remove from rates all generating resources not needed to serve residential and small non-residential

		customers. Under the Division 38 rules, utilities would only acquire new generating resources to serve residential and small nonresidential consumers. Larger-load customers would be served by the market and not the utilities. After the California market meltdown, the Oregon Legislature in 2001 adopted HB 3633, which delayed the implementation date of direct access and required each electric utility to offer a cost of service rate option to all customers. ORS 757.603 permits the Commission to waive its protections only where the Commission can make specific findings designed to protect customers from an electricity market that is not fully functional or that does not produce prices which are just and reasonable. In May 2006, PGE sought a waiver for its proposed acquisition of a wind power project, and acknowledged that the request did not constitute a request for pre-approval of the costs. See discussion in PGE request for waiver: http://edocs.puc.state.or.us/efdocs/HAQ/lc33haq114044.pdf The request was granted in Order No. 06-419, July 20, 2006. The order made it clear that the waiver did not constitute an approval of any specific ratemaking method. The Commission stated it would waive the market rule if, based on current information, customers are likely to be better served by a utility-owned resource, included in rates at cost, instead of comparable market alternatives. The Commission in 2002 had opened a review of the Market Price Rule limitation on utility plant additions to rate base at cost, Docket UM-1066. In 2005, in Order No. 05-133, the Commission put the docket on hold, and determined that it would continue to address the issues raised in that docket in the context of individual waiver proceedings. Meanwhile, the Commission continue to work on speeding up competitive resource acquisition processes, and ensuring that all resources were reviewed on an equal basis. http://apps.puc.state.or.us/orders/2005ords/05-133.pdf On January 16, 2007, in Order 2007-002, Docket UM-1208, the Oregon Public Utility Commission rejected PacifiCorp's request for conditional approval of its plan to seek bids to build two coal plants in order to meet growing energy demands. The Commission found that the company failed to justify the need to acquire the amount

		and type of energy resources sought, and that company's proposal was not consistent with its earlier acknowledged resource plan. In the previously approved plan, PacifiCorp had presented a strategy that included short-term market purchases, renewable resources and conservation to meet growing resource demands. The Chairman explained the reasoning in a Commission press release as follows: "In its Request for Proposals we expected PacifiCorp to fully explore strategies that would allow the company to delay a commitment for a big new central generating plant. It didn't do that. We simply cannot conclude, based on the information provided to us, that it is reasonable for PacifiCorp to make a commitment of this magnitude without further study." PacifiCorp has the option to submit a new plan to the Commission. http://www.puc.state.or.us/PUC/news/2007/2007002.shtml
Pennsylvania	73% average rate increase for customers of Pike County Power & Light Company in January 2006. Anticipated double-digit rate increases in other service areas as transition rate caps begin to come off in 2010.	The Commission in January 2007 rejected a proposal filed in 2006 by Met Ed and PenElec (First Energy subsidiaries) that would have started increasing rates in 2007, in anticipation of the end of their rate caps. (Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan, P-00062213; Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan, P-00062214.) Commission has issued proposed framework for post-transition policies. *See* Appendix II, on Additional Proposed Responses, for details.
Rhode Island	Volatility in New England market, where natural gas and fuel oil set the market clearing price 90% of the hours in the year, per PUC . Increases in SOS costs of 29% in late 2005 as a result of fuel price index effects and natural gas spikes in 2005. Similar increases in 2000-2001, albeit followed by	Initially, under restructuring settlements approved by the Commission, SOS was provided by the utility with wholesale contracts from counterparties who had purchased the utility's plant assets. The Commission has approved a set of wholesale contracts, which provide a base price and fuel indexes, most recently for the years 2006 through 2009. Under the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (2006 General Assembly, S. 2903, signed June 30, 2006): 1) Utilities' obligation to arrange for Standard Offer Service was extended from 2009 through 2020.

	reductions until 2005. Institution of ISO-NE capacity markets in 2006, which added roughly 1 cent/kWh to retail price in Rhode Island (a state with excess capacity).	2) Utilities' obligation to plan and acquire necessary resources now governed by "least cost procurement." Term includes: system reliability, energy efficiency and conservation procurement, and supply procurement. The electric utilities are responsible for procurement plans, which must be approved by the PUC. 3) "The electric distribution company will be entitled to recover its costs incurred from providing the standard offer arising out of: (1) wholesale standard offer supply agreements with power suppliers in effect prior to January 1, 2002; (2) power supply arrangements that are approved by the commission after January 1, 2002; (3) power supply arrangements made pursuant to §§ 39-1-27.3.1 and 39-1-27.8; and (4) any other power supply related arrangements prudently made after January 1, 2002 to provide standard offer supply or to mitigate standard offer supply costs, including costs for system reliability, procurement and least-cost procurement, as provided for in § 39-1-27.7." Separately, Last Resort Service has been defined for customers who are new to the utility's service territory, or who return to utility-procured power after testing the retail market. It is procured for the largest electric utility (Narragansett, a subsidiary of National Grid) by bid for 6-month load-following contracts. See, e.g. *In re Narragansett Electric d/b/a National Grid's Last Resort Acquisition Plan for the Period Beginning May 1, 2007*, Rhode Island PUC Docket No. 3605, Report and Order, February 27, 2007.
Texas	Since January 2002, incumbent utilities received increases in the price to beat between 67% and 114% (depending on the territory). In 2005, Price to Beat rates increased sharply, from 8-9 cents/kWh in 2002-3 to 14 cents in 2006. Utilities did not lower prices when high 2005 gas prices fell back.	On January 1, 2001, all retail customers were put on "price to beat" rates, at a discount of 6% off then-existing rates. On January 1, 2005, incumbent utilities were allowed to offer other rates to their customers, but were required to continue to offer PTP prices until January 1, 2007. Incumbent retail provider utilities can raise "price to beat" twice a year if gas prices go up; no requirement to lower costs. Two utilities did enter into settlements in 2006 to lower their Price to Beat, and the PUC approved these settlements. *See*, *Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas*, Texas PUC, January 2007, at 50, n60, re: Dockets No. 32693 and 32694. http://www.puc.state.tx.us/electric/reports/scope/2007/2007scope_elec.pdf PUC exempted El Paso Electric and other utilities in Southwest Texas from retail

		competition because they are outside of the ERCOT system operator territory and the Commission did not see the prospect of competition benefiting consumers in these areas. *PUC Evaluation of the Readiness of the El Paso Area for Retail Competition in Electricity*, Project No. 28971, Order Adopting New Section 25.421 (Oct. 18, 2004). https://www.puc.state.tx.us/rules/subrules/electric/25.421/28971pub.doc
Virginia	Desire of Dominion, largest utility, to reenter business of building plants, particularly baseload coal and nuclear, but with greater and more explicit protection from risk than before restructuring. In late 2006, fostered by Dominion, a move to "re-regulate" began in advance of the expiration of the transition to competition scheduled for 2010. Rate caps in Virginia for Allegheny Power and Delmarva expire in July of 2007. State lawmakers extended the caps for Dominion Virginia Power, which serves Northern Virginia, through 2010, allowing fuel price increases through 2007.	The General Assembly passed a bill ending the deregulation experiment before the end of the transition period, and providing new protections and benefits for utility shareholders, claimed to be needed to support the ability of Dominion to build needed baseload generation. The Governor made certain changes to the bill, and in April 2007, the governor signed HB3068/SB1416 to expedite re-regulation. The bill's summary containing the governor's recommendations is as follows: "Advances the scheduled expiration of the capped rate period from December 31, 2010, to December 31, 2008, establishes a new mechanism for regulating the rates of investor-owned electric utilities, and limits the ability of most consumers to purchase electric generation service from competing suppliers. The ratemaking procedure requires the State Corporation Commission (SCC) to conduct a rate case for investor-owned utilities in 2009; thereafter, the SCC will review each utility's rates, terms, and conditions using two 12-month test periods ending December 31, 2010, though the SCC is given discretion to stagger the years in which it conducts such reviews. In these biennial reviews the SCC will determine fair rates of return on common equity for the utility's generation and distribution services, using any methodology it finds consistent with the public interest. However, the return shall not be set: (i) lower than the average of the returns on common equity reported to the Securities and Exchange Commission for the three most recent annual periods by a peer group of a majority of the other vertically-integrated investor-owned electric utilities in the southeastern United States with a Moody's bond rating of at least Baa or (ii) higher than 300 basis points above that average. Increases in the rate of return are capped based on the rate of increases in the Consumer Price Index (CPI). The SCC may increase or decrease the rate of return by a Performance Incentive of up to 100 basis points based on the generating plant performance, customer service, operations and efficiency of a utility. In setting the return on equity, the SCC is required to strive to maintain costs of retail electric energy that are cost competitive

		with costs of retail electric energy provided by the other peer group investor-owned electric utilities. If the combined rate of return on common equity earned is no more than one half of one percent above or below this rate of return, the return shall not be considered either excessive or insufficient. Each utility may seek rate adjustment clauses to recover (i) costs for transmission services provided by PJM Interconnection under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission (FERC) and costs of FERC-approved demand response programs; (ii) deferred environmental and reliability costs authorized under prior capped rate rules; (iii) costs of providing incentives for the utility to design and operate fair and effective demand-management, conservation, energy efficiency, and load management programs; (iv) costs of participation in the new renewable energy portfolio standard program; and (v) costs of projects that the SCC finds to be necessary to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations, which costs may include the enhanced rate of return for new base load generation if the project would reduce the need for construction of new generation facilities by enabling the continued operation of existing generation facilities. A utility may also apply a rate adjustment clause for recovery from customers of the costs of (i) a coal-fired generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth, (ii) one or more other generation facilities, or (iii) one or more major unit modifications of generation facilities, to meet the utility's projected native load obligations. The utility may recover an enhanced rate of return on common equity associated with the type of project, which may include projects utilizing nuclear power, renewable technologies, carbon capture facilities, combined cycle combustion turbines, and conventional coal facilities. The period over which the enhanced rate of return may be collected depends on the type of facility, as determined by the SCC within specified ranges. The SCC's final order on any petition filed for any of the rate adjustment clauses shall be entered within a specified period after the filing of the petition, and any rate increase required by the clause shall go into effect within 60 days or upon the end of capped rates, whichever is later. The SCC is required to consider petitions for rate adjustment clauses on a stand-alone basis, without regard to the other costs or revenues of the utility. The enhanced returns are subject to revocation if permits are

		not applied for or construction is not commenced by specified dates. If the SCC determines in a biennial review that a utility underearned by at least 50 basis points on its generation and distribution services, excluding provisions for new generation facilities, the SCC is required to increase the utility's rates to a level necessary to provide the opportunity to fully recover the costs of providing the utility's services and to earn such fair rate of return. If the SCC determines in a biennial review that a utility earned more than 50 basis points above a fair combined rate of return on its generation and distribution services, excluding provisions for new generation facilities, the SCC is required to direct that 60 percent of such overearnings be credited to customers' bills over a period of between 6 and 12 months, to be determined by the SCC. In addition, if the SCC determines that the utility's earnings exceed this limit for two consecutive biennial review periods, it shall also order reductions to the utility's rates, provided that rates may not be reduced to levels below what would provide the utility with the opportunity to fully recover its costs and to earn a fair combined rate of return on its generation and distribution services, excluding provisions for new generation facilities. If the Commission determines that and the utility's total aggregate regulated rates would exceed the annual increases in CPI, when compared to the utility's rates as determined in the biennial review for a base period (either the utility's first test period or the most recent test period for which credits are applied to customers' bills), the Commission shall direct, unless such action would not be in the public interest, that any or all of such overearnings be credited to customers' bills. An electric utility that demonstrates that it has a reasonable expectation of achieving 12 percent of its base year electric energy sales from certain renewable energy sources during calendar year 2022 may participate in a renewable energy portfolio standard program. Under the program, a participating utility that meets specified percentage goals for sales of eligible renewable energy is eligible for a Performance Incentive that increases the fair combined rate of return on common equity for the utility by a 50 basis points through the third succeeding biennial review if it continues to meet the RPS Goals. It is also entitled to an enhanced rate of return on the costs associated with the construction of renewable energy generation facilities used to provide the renewable energy. Participating utilities may recover their incremental costs of meeting the RPS Goals from customers other than large industrial customers purchasing

		electricity at large general service rates and at primary or transmission voltage. Double credits will be provided for energy from solar or wind sources. Specific provisions address the use of certain wood products for projects qualifying to meet the renewable energy goals. With regard to the ability of customers to purchase generation services from competing providers, the measure provides that after the capped rate period ends, only customers whose annual demand exceeds five megawatts will be permitted to shop. However, two or more individual nonresidential retail customers may aggregate their demand for the purpose of meeting the five megawatt threshold if the Commission finds that neither their incumbent electric utility nor its retail customers will be adversely affected and that the demand of the customers who are allowed to buy power from competitors will not exceed one percent of the utility’s peak annual load. Aggregating customers may petition the SCC to aggregate their supply, even if their aggregated load exceeds 1% of the utility’s demand, if the aggregation would not harm other utility customers or the utility. The ability of large customers to purchase electric power from a licensed competitive supplier is subject to the condition that they cannot thereafter purchase electricity from their incumbent utility without giving 5 years’ notice, with certain exceptions; however, the 5-year notice requirement does not apply if the SCC finds that waiving it would not harm other utility customers or the utility. Municipalities are allowed to aggregate the electric energy load of their governmental operations for the purpose of negotiating rates and terms, and conditions of service from the electric utility certificated by the Commission to serve the territory in which such operations are located. Other provisions (i) require the deferral over the period 2008-2010 of a portion of Dominion's 2007 fuel factor increase; (ii) authorize electric utilities to seek approval of optional performance-based regulation methodologies to the same extent as gas utilities; (iii) require that 75 percent of the margins from off-system sales be applied to the utility's fuel expenses unless the SCC finds by clear and convincing evidence that a smaller percentage is in the public interest; (iv) require rates of distribution electric cooperatives to be regulated pursuant to the provisions of Chapters 9.1 and 10 of Title 56, subject to the ability to increase rates without SCC approval by not more than five percent over three years and to make certain other changes to terms and conditions of service; (v) provide that the measure does not modify or impair the

		terms, unless otherwise modified by an order of the SCC, of any SCC order approving the divestiture of generation assets; (vi) direct the SCC to complete by December 15, 2007, a proceeding to develop a plan to identify and implement demand side management, conservation, energy efficiency, load management, real-time pricing, and consumer education programs in order to achieve by 2022 a stated goal of reducing the consumption of electric energy by retail customers by ten percent of the amount consumed by such customers in 2006; (vii) direct the Office of the Attorney General to identify issues of the act that impede its implementation; (viii) direct the Department of Taxation is directed to conduct an analysis of the potential implications of the provisions of this measure on the system of taxation; (ix) ensure that utilities use competitive bidding in purchasing and construction practices; (x) increase the cap on power that a utility may be required to purchase from eligible customer-generators under the net energy metering program from 0.1% to one percent of the utility's adjusted peal load; and (xi) allow competitive service providers to offer 100% renewable power to retail customers in any area of the Commonwealth where the customer's incumbent utility does not offer such a tariff. Provisions of the Electric Utility Restructuring Act that exempt the generation of electric energy from regulation, prohibit public service corporations from exercising the power of eminent domain to acquire property for generation facilities, authorize the collection of wires charges, and authorize competition for metering and billing services are repealed. This bill is identical to SB 1416."