State Regulatory Update: Rate Impact Mitigation Measures

Prepared by:
Bruce Edelston
Energy Policy Group, LLC
Atlanta, GA

Prepared for:
Edison Electric Institute

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1. Introduction

During the 1980s and 1990s, and to some extent the early part of the current decade, the electric utility industry enjoyed a period where costs of generating power were relatively stable, an earlier building boom had resulted in reduced investment needs for new construction, and the industry’s environmental requirements were fairly stable and known. While rate adjustments, and particularly fuel adjustments, were still required fairly often, they were usually minor adjustments and were just as often rate reductions as they were rate increases. In addition, the restructuring of the industry that occurred in many states during this same period was usually accompanied by negotiated rate freezes or settlements which either delayed or tempered rate increases for at least a period of time.

In many regions of the country, the environment in which electric utilities operate has changed substantially in the past several years. To a large extent, the extra capacity that the industry had available is beginning to dry up, and new plants are needed in parts of the country. Environmental requirements and renewable portfolio requirements in many states continue to be imposed, resulting in additional investment needs. Fuel prices have been more volatile over the past several years than they were in the previous decade, resulting in the need for more frequent rate adjustments. And in many of the restructured states where negotiated freezes or settlements have been in place, those agreements either have expired or will soon expire. When these agreements expire, there can be significant cost impacts on consumers when they move from receiving rates that were set in the restructuring transition process to having their rates essentially be determined by the competitive marketplace. Both increased investment needs and increasing and volatile fuel prices have contributed in the past several years to a marked increase in the need for rate filings. However, what is different in the current round of filings is that – partially because rates have been steady or even declining in real terms for so long – the magnitude of some of the potential rate increases (and particularly for base rate increases) is greater than what we have ever seen before in the utility industry.

Moreover, while natural disasters are by no means a new phenomenon, over the past five years or so the nation has experienced disasters (particularly hurricanes and ice storms) that have required almost total rebuilding of some electric systems – again resulting in the need for sudden and sharp increases in rates to pay for these obviously needed investments. While insurance and storm reserve funds maintained by most utilities certainly help in these situations, they are seldom sufficient.

All of these legitimate needs for utility rate increases are occurring at the worst possible time. The nation has been in a deep recession, unemployment rates are high, and many electric consumers may face a difficult time absorbing these rate increases. Moreover, separate and apart from the general economy, natural disasters themselves cause physical and economic devastation, and certainly consumers are ill-prepared for the rate increases that result from utilities making major investments to help communities recover from such disasters.
Thus, both electric utilities and their economic regulators – the state public utility commissions – are increasingly looking for ways of mitigating the impacts on consumers of substantial rate increases, while still ensuring that the utilities remain financially healthy and able to continue to provide reliable electric service. These rate impact mitigation measures may rely on variances in the time value of money, require a phase-in of rate increases, allow the utility to take advantage of lower cost financing for certain investments, or simply time rate increases to coincide with other events to cushion the impact. Such mechanisms may also allow special accounting treatments for the utility or special payment plans for customers.

The need for rate mitigation measures is not a short-term phenomenon. The need for utilities to meet existing environmental regulations and state or possible federal climate change requirements, the ever-increasing renewable requirements that some utilities must meet, the need to add new generation and transmission capacity just to meet normal growth requirements and to replace aging infrastructure all mean the need for rate increase filings over the next several years. Utilities are being asked to make major investments in the smart grid as well. Fossil fuel prices are likely to exhibit volatility for the foreseeable future. All of this suggests that we will continue to need to address means to mitigate the impacts of rapidly increasing costs on electric consumers.

The purpose of this report is to look at some of these rate impact or “rate shock” mitigation measures that have been employed by regulators to gain a greater understanding of the types of mechanisms available and the situations where they may be applicable. This report is not intended to be an exhaustive survey of all of the rate impact mitigation measures that have been developed and approved, but rather to give examples of these measures applied to different situations. Some cases not discussed in this report are included in periodic reports published by EEI. In addition, we do not go into depth on all the issues raised in the specific regulatory cases discussed but rather focus on the outcomes. Sufficient information is provided for the reader to review all the filings and decisions for the cases presented on the relevant state commission website.

We review only cases since 2005 as being the most relevant to utilities considering similar approaches today. There are also certain kinds of “mitigation” that we don’t cover in this report. We do not include cases where rate increases are simply denied, where authorized rates of return are reduced, or where effective dates of increases are simply delayed (as opposed to being phased in). While these situations might be considered “mitigation,” many are covered in other EEI rate case updates and are of limited general interest. We also don’t cover regular cases involving automatic adjustment mechanisms or fuel adjustment clauses, construction work in progress (CWIP) or allowance for funds used during construction (AFUDC), all of which can also be considered rate impact mitigation measures. These methods are discussed in detail in other EEI reports.¹

Finally, while most of the mitigation measures presented in this report are based on final state commission decisions, we have also presented some proposed measures that have been filed at the commissions but not adjudicated, and also some state legislative proposals that may be of particular interest to the reader.

¹ See, for example, Pacific Economics Group, Alternative Regulation for Infrastructure Cost Recovery, January 2007; The Brattle Group, Rate Shock Mitigation, June 2007; and, The Brattle Group, Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations, November 2006, all prepared for the Edison Electric Institute.
The following section categorizes and discusses the various types of rate impact mitigation measures. Section 3 provides a summary of the cases reviewed, organized by the various types of rate impact mitigation measures that are discussed in Section 2. Finally, Section 4 provides some observations about trends and some conclusions based on a review of the cases.

2. Types of Rate Impact Mitigation Measures

2.a. Rate Cap Expiration Cases

By far the most common type of rate impact mitigation employed by regulators to date has been associated with the expiration of long-term rate caps and freezes, and the rate impacts that have been experienced in moving from cost-based rates to market-based rates as the transition to competitive electric markets nears completion. This makes logical sense because it has also been the most common reason for major rate increase requests in the past decade. The rate caps were set as part of the process of electric restructuring and customer choice programs. Rates were often frozen in these programs beginning in the mid-1990s in many states, and in many cases, rates were even reduced before they were frozen. Utilities made deals with their legislatures and regulators to recover stranded costs of generation no longer economic in a competitive environment, in exchange for which they agreed to long-term rate caps that would remain in place – usually until stranded costs were fully recovered.

At the time these rate freezes were instituted, we were in a natural gas bubble, we had more generating capacity than we needed in some parts of the country, and the marginal costs of new gas-fired generation, even taking into account construction costs, were often lower than those of much of the embedded generation around the country (and hence, the stranded cost problem). Many observers believed that competitive wholesale markets and retail customer choice would reduce costs to customers in both nominal and real terms, even with stranded cost recovery. But the gas bubble did not stay, conflict arose in the Middle East, and the depletion of extra generating capacity around the country did not allow the vision of continued stable or declining prices to be realized – in either restructured electric utility markets or traditionally regulated markets. Costs began to increase in all areas of the country.

Problems were further exacerbated by the California and western power crises of 2000-01, where costs to customers skyrocketed and absolutely had to be mitigated in some way to protect the economic welfare of those states. The California experience was really the flashpoint that saw the beginnings of many of the rate impact mitigation measures that we see today.

This report is limited to cases decided after January 1, 2005, so it does not cover all of the mitigation measures that were put in place following the western crises, nor does it cover the many mechanisms established in those states where rate caps came off earlier than 2005 – such as in California and Texas. However, the issues are very much the same for utilities that have seen their rate caps expire in the past few years, and those few companies still awaiting expiration. Costs are still increasing and to some degree, the market prices today are still significantly higher than capped regulated prices, and increases of 10, 20, 30, 50 percent or even higher are often necessary to move customers from regulated to market-based rates.

There are various kinds of rate impact mitigation measures for dealing with the expiration of rate caps and freezes. In some cases, the problem is dealt with by extending the freeze, often with utilities being allowed to defer cost recovery (via a regulatory asset) for the higher cost of power while the rate freeze is still in effect.
After expiration of the freeze, utilities would amortize and recover those costs – possibly with the associated carrying charges included. Cases involving an extension of caps and phase-ins reviewed for this report include the Ameren–IL Rate Mitigation Rider, Commonwealth Edison (ComEd) Rate Stabilization Plan, and Ameren–IL Customer Elect Plan Rider, all in Illinois, and a Baltimore Gas and Electric (BGE) Phase-in case in Maryland.

Another common mitigation measure is to allow customers to begin paying the higher expected costs of market prices before the rate caps expire and then crediting those pre-payments – with interest – back to the customer after the caps expire. Sometimes these programs are targeted at certain customers – such as those with electric space heating – to focus solutions on those with the greatest expected cost burden. Cases of this nature discussed below include PECO Energy’s Transition Phase-in Plan and Pennsylvania Electric and Metropolitan Edison’s Voluntary Prepayment Plans in Pennsylvania, and BGE’s Rate Stabilization Plan, Potomac Edison’s Rate Transition Plan, and Pepco and Delmarva Power & Light’s Transition Rate Phase-in Plans, all in Maryland.

A variation of extending the freeze is a gradual phase-in of market-based prices. This is similar to extending the rate freeze period, but instead some portion of the rate freeze would be lifted each year to move the customer gradually to market prices. These phase-ins, however, still raise the issue of deferred power supply costs and the necessity to eventually recover those costs and associated carrying charges. Tucson Electric Power’s Transition Plan in Arizona is an example of this type of transition plan.

Costs can sometimes lead things in the opposite direction as well. We found a few cases where legislatures, regulators or utilities actually decided to speed up the end of rate cap periods. This can be for several reasons, e.g., the timing may be such that power supply costs are in a down period relative to what could be the case later. For example, this past year has seen declining and low gas prices, so if the rate freeze period termination could be timed to coincide with the current low fuel (and power supply) costs, rate impacts could be mitigated. In this report, we cite a bill passed by the Virginia legislature terminating a rate cap earlier than planned due to market conditions.

b. Timing of Rate Increases to Mitigate Rate Impacts

The second largest class of cases that involve rate impact mitigation measures, and the one that at least recently has been seeing the most growth, is adjusting the timing of rate increases to mitigate rate impacts. In a large number of these cases, utilities and their regulatory commissions are simply taking advantage of market conditions – and lower fuel prices in particular – to blunt the impact of what might otherwise be significant rate impacts. This trend has in turn been made possible by the recent dip in fuel (and especially natural gas) prices relative to where those prices were two to three years ago. Thus, utilities are able to reduce fuel adjustment clause collections in concert with base rate increases, with a result of smaller – or even negative – overall rate impacts. Such timing effects have been used in cases involving Idaho Power and Avista (extensions of Power Cost Adjustments) in Idaho, a Dominion Virginia Power rate case and fuel cost recovery case in Virginia, a Northern States Power rate increase request in Wisconsin, an El Paso Electric rate increase and fuel charge reduction case in Texas, and an Oklahoma Gas and Electric rate increase request in Oklahoma, all reviewed in Section 3 below.
It is important to note that almost all of these cases rely on current market conditions, and are only possible in periods when fuel costs (or other costs recovered on automatic adjustment clauses or riders) are declining.

There are other cases where the timing of proposed rate increases has been adjusted to mitigate potential rate impacts. In most of these cases, rate increases that were scheduled to occur at one time have been typically divided into a series of two or three (or even more) smaller rate increases over a period of time. In most of these cases, the total revenue and rate impact at the end of the phase-in period is the same as it would be if the rate increase had been implemented at once, but customers presumably are given more time to adjust. Cases reviewed in this report where a phase-in has been utilized to mitigate rate impacts include an extension of Competitive Transition Charge recovery filed by Niagara Mohawk, and a Consolidated Edison Co. of New York Rate increase request including a phase-in, both in New York; a South Carolina Electric & Gas proposal in South Carolina; a Duke Energy proposal in North Carolina; a Nevada Power proposal in Nevada; a Minnesota Power request in Minnesota; and a Public Service Co. of New Mexico filing in New Mexico.

**c. Securitization Cases**

Securitization is a financial tool that essentially packages bonds backed by fairly certain recovery and sells the bonds on the market as a highly rated security. By ensuring that the money being invested from the proceeds of these bonds has a high probability of being paid back – usually because a state legislature has mandated that the costs associated with repayment will be placed on customer bills as a surcharge – the bonds can be rated highly and thus get much lower interest rates than the utility would get by financing the investments itself. These lower interest costs then translate into lower costs for customers when they pay the servicing costs of the bonds through surcharges.

The first uses of this mechanism in the investor-owned electric utility segment were for so-called “stranded cost” bonds, where utilities – authorized by state legislatures – would set up a stranded cost securitization account, replenished by a surcharge on customer rates to pay whatever amount of stranded costs were allowed by the state. The state or utility would sell securitization bonds and the proceeds would be used by the utility to accelerate the depreciation on portions of their stranded plants to their market levels, with the bonds repaid from the customer surcharges. A relatively recent case reviewed for this study involving securitization of transition costs by BGE in Maryland is typical of this type of rate impact mitigation measure.

When rates skyrocketed in the western energy crises of 2000-01, securitization again became a popular means of trying to mitigate some of the rate increases that became necessary. For example, some utilities accounted for increased purchased power costs in a regulatory asset, and then financed that regulatory asset through securitization.

Paying the recovery costs from large storms or other catastrophic events has been another increasing use for securitization. Florida Power & Light in Florida, Mississippi Power and Entergy in Mississippi, American Electric Power (AEP) in Texas and others have all used securitization for this purpose, and those cases are discussed below. A new category of application also is beginning to emerge as a logical extension. The costs of pollution control, particularly on existing plants, are going to be immense. Securitization may (and to some extent has) become a tool to reduce the rate impacts associated with these very large investments.²

Section 3.c. provides an example of securitization for pollution control purposes involving Allegheny Energy in West Virginia.

Securitization is not always a preferred mechanism for dealing with rate mitigation. First it requires the legislature to act in most cases, followed by a favorable ruling from the regulator and then the underwriters. It is not an easy process and lots can go wrong. In most cases of securitization, the utility cannot earn on whatever investment results from the proceeds. So for example, if a utility is using securitization to finance the reconstruction of a large part of its system, it might not be able to earn on that investment in the future, and thus could face a substantially reduced rate base.

It’s also important to note the failure that another type of securitization – that involving the bundling of home mortgages – has rightly or wrongly taken substantial blame for the country’s economic and financial crisis in 2008-09. It is unclear what effect this might have on the viability and cost of utility securitizations in the future.

d. Rate Design Changes to Mitigate Rate Increases

While most rate impact mitigation measures rely on changes to the level and timing of revenue requirement changes, there have been some instances where rate design changes have been made to soften the impact of rate increases on particular customers or customer classes, without changing the overall annual revenue requirement approved for the utility. In the cases reviewed for this report, the commissions noted in approving these rate design changes that they were departing from the norm of rates based on cost of service. They asserted that such changes were necessary and in the public interest. The commissions also sought to make clear that they were not establishing precedents, and that their decisions would not impose undue hardships on other classes of customers. The cases where rate design has been used to mitigate rate impacts include the ComEd and Ameren Rate Design decisions in Illinois and the Connecticut Light & Power Standard Service Rates decision by the Connecticut commission, all reviewed below.

e. Negotiated Mitigation Plans

In at least a few instances, the political fallout from approved rate increases has led to the threat of action by state legislatures to unilaterally impose rate reductions. In some of these cases the threat of action by the legislature has in turn led to negotiated agreements among the affected utility, the state governor, and other parties including legislative leaders, consumer groups, the attorney general and others. These negotiated agreements have involved the implementation of rate impact mitigation measures, agreement by the utilities to reduce overall rate levels, and sometimes even monetary contributions by the utilities to fund special programs. In the two “globally” negotiated settlements reviewed for this report, the agreements became the basis for legislation. The cases reviewed here involve ComEd and Ameren in Illinois and Appalachian Power (AEP) in Virginia. Similar legislation in Maryland is reviewed in the “Rate Cap Expiration” section below.

f. Customer Assistance Programs

Most utilities have some type of customer assistance program whereby they contribute (and/or match customer contributions) to low-income and special needs customer programs. While these programs are generally voluntary, there have been cases where contributions to customer assistance programs have been
included in regulatory decisions specifically as rate impact mitigation measures. For example, a rate filing by Kansas City Power & Light in Missouri included an Economic Relief Pilot Program intended to provide monthly assistance to qualified customers who have trouble paying their electric bills. In Illinois in a decision on ComEd’s proposed Rate Stabilization Plan, the Illinois Commerce Commission “strongly encouraged” ComEd to voluntarily contribute $30 million over the next three years to low-income assistance and senior programs as well as energy efficiency and renewable energy programs.

3. Rate Impact Mitigation Cases

a. Rate Cap Expiration Cases

**Pennsylvania PUC – PECO Energy (PECO) Transition Phase-in Plan**

Decided 3/12/09        Filed 9/10/08        Case P-2008-2062741

PECO’s in its filing requested expedited approval of a Phase-In Program designed to give eligible customers a rate option to help them manage the transition from capped generation rates to market-priced generation, which will occur on January 1, 2011, by allowing participating customers to make advance payments from July 1, 2009 through December 21, 2010. The advance payments, with interest, would then be credited to their bills, between January 1, 2011, and December 31, 2012. PECO specifically requested that the commission: (1) approve the proposed Phase-In Program; (2) approve an automatic adjustment clause to recover the costs of implementing and administering the program; and (3) permit the Phase-In Program tariff supplement to become effective on one day’s notice after entry of the commission’s order.

On January 30, 2009, many of the parties to the case filed a joint Settlement Petition, subsequently approved by the Pennsylvania Public Utility Commission. The Settlement provides that PECO is to file tariffs giving eligible customers the option, beginning July 1, 2009, of having surcharges added to their monthly bills according to a set schedule of surcharges through a Voluntary Market Rate Phase-In Rider. Beginning on January 1, 2011, credits will be applied to the monthly bills of participating customers. The Settlement Petition provides a set of factors that will be applied to customers’ balances of prepayments and accrued interest at December 31, 2010 in order to determine the monthly credits to be issued on the customer’s account. The factors were developed to refund the prepaid balance, including accrued interest at 6% per annum compounded monthly, in a manner that, together with the anticipated increase in the price of generation service, will phase in the increase in customers’ total bills on a gradual basis over the refund period.

All customers below 500 kW are entitled to participate, whether they receive default service from PECO or purchase generation service from a competitive electric generation supplier.

The Settlement also provides that PECO may defer, without interest, as a regulatory asset on its balance sheet, implementation and administration expenses and other expenses associated with the Phase-In Program until the effective date of the rates established in PECO’s next distribution base rate case. The deferred expenses found to be reasonable by the commission will be recovered through an amortization without interest.
Pennsylvania PUC – Pennsylvania Electric (Penelec) and Metropolitan Edison (Met-Ed) Voluntary Prepayment Plan
Decided 2/26/09 Filed 9/25/08 Case P-2008-2066692

Penelec and Met-Ed, both subsidiaries of First Energy Corp., filed with the Pennsylvania PUC for approval of a Voluntary Prepayment Plan (VPP). In January 2009, the companies reached a Settlement with the Pennsylvania Office of Consumer Advocate and Office of Small Business Advocate, which was subsequently accepted by the commission. The VPP is designed to allow customers to smooth out the increases for supply service that will occur when the companies’ generation rate caps expire on December 31, 2010. These rate caps were established when the electric industry was restructured in Pennsylvania in 1996.

Under the VPP, residential and small commercial customers can opt to pay a monthly charge from March 2009 through December 2010. The monthly charge is designed to collect 9.6% of the then current average price – including the VPP – plus any other rate changes put into effect during the collection period. The amount collected plus 7.5% interest would then be paid back to those customers in the form of a VPP credit on participating customers’ bills from January 2011 to December 2012. The 7.5% interest is based on the companies’ average weighted cost of capital as determined in their approved Rate Transition Plan.

Arizona CC – Tucson Electric Power (TEP) Transition Plan
Decided 12/1/08 Filed 7/2/07 Case E-01933A-07-0402 and E-O1933A-05-0650

Pursuant to a 1999 Settlement Agreement with the Arizona Corporation Commission (ACC), TEP rates were frozen through 2008. TEP filed a plan to mitigate the impact of a projected 23% rate increase scheduled for 2009 by phasing it in over four years through 2012. The Settlement Agreement in the case establishes an Implementation Cost Recovery Asset (ICRA) which reflects the costs TEP incurred in the transition to retail competition. The agreement provides that the ICRA is to be amortized over a four-year period and recovered in rates, and that it will not be included in rate base or as an amortization expense in TEP’s next rate case. The agreement also provides for a rate case moratorium until December 31, 2012.

Maryland PSC – Baltimore Gas and Electric (BGE) Rate Stabilization Plan
Decided 5/23/07 Filed 1/26/07 Case 9099

BGE made this filing to implement the opt-in short-term rate stabilization plan as required by SB 1 (see below). BGE proposed to offer Rate Stabilization Plan II (RSP II) effective June 1, 2007. RSP II would provide for a deferral credit to be included on the bills of all residential customers choosing to participate in this plan. BGE proposed that there be two approximately equal percentage rate increases for RSP II participants: an intermediate rate increase effective June 1, 2007, and a second increase effective January 1, 2008, to reach the full market rate. Based on the results of prior procurement auctions, BGE estimated the necessary rate increases to be in the range of 45 to 49%. Thus, it projected that two rate increases slightly higher than 20% would be necessary to reach the full market rate.

BGE also proposed that starting on January 1, 2008, a “deferral recovery charge” be billed to each residential customer who participated in the voluntary program over a two-year period ending December 31, 2009. The “deferral recovery charge” would be designed to recover the actual deferred power supply costs incurred on behalf of the plan participants during the term of the plan along with the associated carrying costs.
In its Order, the Maryland PSC “reluctantly” approved BGE’s request to increase rates to complete the transition to market prices for BGE customers. However, the commission rejected BGE’s RSP II proposal in favor of an alternative plan advanced by commission staff. Staff’s plan uses the existing structure of BGE’s rates to more gradually transition the participating customers to market rates through a total of three rate transitions over the same seven-month period as BGE’s proposal. Staff’s plan also has a three-month grace period built in before the participating customers’ rates are adjusted to begin repayment of RSP II deferred charges. The commission found that while BGE’s two-step plan is simpler in nature, the overall goal of transitioning the ratepayer to full market rates should be paramount.

The RSP II plan approved by the commission incorporates a deferral recovery period beginning on April 1, 2008, and ending on December 31, 2009. Any over- or under-collections of the deferred costs would be trued up in 2010. In accordance with an offer made by BGE regarding the collection of interest on the amounts deferred, no interest is to be charged to customers who opt in to the RSP II.

Virginia Legislature – Early Termination of Rate Cap Period

Enacted 4/4/07  Law SB 1416

This Virginia law advanced the scheduled expiration of the capped rate period from December 31, 2010, to December 31, 2008, established a new mechanism for regulating the rates of investor-owned electric utilities, and limited the ability of most consumers to purchase electric generation service from competing suppliers. The primary purpose of accelerating the termination of the rate freeze period was to take advantage of relatively low wholesale power prices at the time of termination, and thus mitigate potential rate increases at the end of the capped period. The Act also provides that after the termination of capped rates, only individual retail customers with demand greater than five megawatts (but less than 1% of the customer’s incumbent electric utility’s peak load, unless greater than 90 megawatts) can purchase electricity competitively.

The Act specifies the basis for establishing utility authorized returns in rate cases. It also authorizes utilities to seek rate adjustment clauses to recover Federal Energy Regulatory Commission (FERC)-approved transmission and demand-side management costs, deferred environmental and reliability costs authorized under prior capped rate rules, costs of providing incentives for the utility to design and operate fair and effective demand management, conservation, energy efficiency, and load management programs, costs of participation in the new voluntary renewable energy portfolio standard program, and costs of projects that the Virginia State Corporation Commission 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.

The Act also repealed provisions of the Electric Utility Restructuring Act that exempted the generation of electric energy from regulation, prohibited public service corporations from exercising the power of eminent domain to acquire property for generation facilities, authorized the collection of wires charges, and authorized competition for metering and billing services.

Maryland PSC – Potomac Edison (dba Allegheny Power (AP)) Rate Transition Plan

Decided 3/30/2007  Filed 12/29/06  Case 9091

The Maryland Public Service Commission initiated this proceeding pursuant to the provisions of Section 8 of Senate Bill 1 (see below to investigate available options for implementing a rate stabilization plan for AP’s residential customers. In response, AP filed a plan proposing a rate mitigation plan to address rate increases expected when its transition rate caps and a Temporary Customer Choice Credit expire on December 31, 2008. AP’s Transition Plan has four goals: (1) to mitigate rate shock associated with market-based rates,
which will be implemented January 1, 2009; (2) to achieve rate gradualism and stabilize bills; (3) to permit customers to continue to receive the benefits of AP’s restructuring settlement through December 31, 2008; and (4) to allow the competitive retail generation market to continue to develop.

AP proposed in its initial Transition Plan to raise customer rates by 15% beginning March 31, 2007. Thereafter, each January residential rates would be increased by an additional 15% during the Plan. Monies collected through the surcharge would earn interest at the average rate AP earns on its external cash investments. Beginning January 1, 2009, when market rates take effect, the surcharge would change to a credit thereby reducing the impact on residential customers of the anticipated higher market rates. The credit would continue in effect with adjustments to maintain rate stability until its termination on December 31, 2010.

During the proceedings, responding to objections about the mandatory nature of the plan, AP filed a revised plan allowing customers to opt out of the surcharge. AP also amended its proposal to provide for customer credits based upon whether a customer is a heating (high usage) or non-heating (lower usage) customer, rather than being based on residential averages as initially proposed. The commission accepted AP’s proposed transition plan with these two changes incorporated.

**Illinois CC – Ameren–IL Rate Mitigation Riders**

Decided 3/12/07   Filed 3/7/07    Case 07-0174

The commission previously approved an optional deferred billing plan under the Customer Elect Plan Rider (Rider CEP) to allow residential and small commercial customers, certain primary and secondary schools, and certain local governmental customers to phase in the effect of expected rate increases beginning on January 2, 2007, for Ameren (see below). Additionally, on February 15, 2007, the commission approved a technical modification to Rider CEP that would facilitate the plan’s objectives for the benefit of electric space-heating customers.

By approving Rider CEP, the commission allowed Ameren to put in place a plan to mitigate expected rate increases by deferring payment during a three-year transitory period, from 2007-09. In this docket, Ameren asked the commission to allow them to modify Rider CEP to eliminate all interest charges under the rider in order to further mitigate the increase in rates. Ameren also asked the commission to modify certain dates, rate adjustments and repayments in Rider CEP to ease the effect of the new rates on customers participating in the CEP.

Ameren also proposed to provide additional financial assistance during the upcoming winter season in addition to the other measures they have already proposed or are proposing, through a new “Rate Mitigation Credit (RMC)” Rider. This additional assistance would be targeted at residential customers with high winter usage, which, in combination with the new rates, has produced significantly higher electric bills. In an order dated five days after the Ameren-IL filing, the ICC conditionally accepted the proposed mitigation measures.

**Illinois CC – Commonwealth Edison (ComEd) Rate Stabilization Plan**

Decided 12/20/06    Filed 5/23/06    Case 06-0411

ComEd’s proposed residential rate stabilization program phases in rate increases associated with the transition from a legislatively mandated rate freeze to market prices (as determined through a competitive procurement program) over a three-year period, with deferred recovery at an appropriate rate of return.
ComEd states that the goal of the Residential Rate Stabilization Program (RRS Program) is to help residential customers manage the transition from long-frozen reduced rates to rates set using ComEd’s actual costs. Under the RRS proposal, ComEd would cap the increase in average annual residential rates per kilowatt-hour to no more than 8%, 7%, and 6% in 2007, 2008, and 2009, respectively. All unrecovered costs above these caps would be capitalized as a regulatory asset. ComEd also sought recovery of its carrying costs related to the regulatory asset created. Any unrecovered balance in the regulatory asset at the end of the Plan would be spread out and recovered over three years, from 2010 through 2012. ComEd also included in its filing a request that it be allowed to terminate the program if its bond ratings fell below a specified level or if ComEd’s financial viability were otherwise threatened.

During the proceeding, ComEd agreed to a staff stipulation that it only accrue carrying charges on deferral balances at the rate of 6.5% per year. In its Order, the commission accepted ComEd’s proposal with some modifications. The commission also changed the carrying charges that ComEd would be allowed to apply to the regulatory asset from 6.5% to 3.25%, as the “mid-point between zero and 6.5%.” The commission stated that “a 3.25% rate for deferrals makes the RRS Program a very attractive option for residential customers who will be challenged with an appreciable increase in their electric bills.”

**Illinois CC – Ameren–IL Customer Elect Plan Rider**

Decided 12/20/06   Filed 12/6/06   Case 06-0779

The Ameren rates for bundled electric service were frozen during a transition period mandated by the Customer Choice Law of 1997. Under the terms of that law, the rate freeze ended on January 2, 2007. The Illinois Commerce Commission approved new delivery service and basic generation service tariffs for the Ameren Illinois Utilities establishing rates for bundled electric service on and after January 2, 2007, in Docket Nos. 05-0160 and 06-0070.

In this docket, Ameren proposed the approval of a Customer Elect Plan (CEP) Rider to implement an optional deferred billing plan that would allow residential and small commercial customers, primary and secondary schools, and certain local governmental customers to phase in the effect of the rate changes that those customers were expected to experience beginning on January 2, 2007, based on the tariffs approved in Docket Nos. 05-0160 and 06-0070. Ameren had previously proposed a voluntary phase-in plan that would be available only to residential customers and would only be effective from May 2007 through December 2009. In response to legislative discussions and customer input, Ameren developed this new proposal as a significant enhancement to the previous plan.

This proposal expands plan eligibility for participation from residential customers to also include small commercial customers, primary and secondary schools, and selected local governmental units (e.g., municipalities). In addition, Ameren reduced the interest charges on deferred amounts by 50%, from 6.5% to 3.25%. The plan also lowered the annual rate phase-in cap to 14% for each of the three years 2007-09, from 15% in the previous plan for the same period. The plan remains a voluntary choice on the part of the customer. Ameren also proposed to make a monetary contribution to program funding, subject to approval of Rider CEP. Ameren specified that in the event of a downgrade to non-investment grade status by Moody’s or Standard & Poor’s, the plan would be terminated and the company would accelerate recovery of deferred amounts.

Under the plan, eligible customers who enroll will receive rate caps in 2007-09 that limit increases to 14% over the average rate charged to their group in the prior year. Eligible customers may enroll through August 21, 2007, but customers who enroll by April 10, 2007, would be allowed to retroactively defer rate increases.
to January 2, 2007. Deferred balances will accrue interest at an annual rate of 3.25% and repayment will occur during the 2010-12 period, through a monthly levelized charge.

In an Order dated 12/20/06, the commission accepted the Ameren proposal without change.

Maryland Legislature – Baltimore Gas and Electric Phase-in Plan
Enacted 6/23/06 SB 1 (Relates to PSC Case 9052)

SB 1, enacted over the governor’s veto, established a new plan for phasing in BGE’s 72% rate increase and superseding earlier commission orders. The law provides for an initial rate increase starting at 15% on July 1, 2006, for all BGE residential and small commercial Standard Offer Service customers. As of June 1, 2007, customers were provided the option to receive the remainder of the full (72%) increase or to participate in an interim plan to be adopted by the Maryland Public Service Commission, which would phase in the rest of increase through January 1, 2008, when all customers would be subject to the full increase. All customers participating in the alternate commission plan were to begin paying back deferred costs plus interest on January 1, 2007, estimated at $2.19 per month, and to continue those payments over the next 10 years. BGE was required to further mitigate the increase through a $387 million rate reduction over 10 years. This reduction would be funded by BGE from foregoing collection of the residential return component of its administrative charges and crediting annual nuclear decommissioning charges previously collected from residential customers. Carrying charges on deferrals are based on BGE’s cost of debt unless deferrals are securitized.

Maryland PSC – Pepco and Delmarva Power & Light Transition Rate Phase-in Plan
Decided 3/21/2006 Filed N/A Case 9058

The Maryland Public Service Commission initiated this case to determine whether a rate stabilization plan for the residential customers of Pepco and Delmarva should be implemented to ease the impact of record electricity prices. The commission instituted a similar proceeding for BGE in Case 9052.

On March 15, 2006, Pepco, Delmarva and the commission staff filed a proposed Settlement Agreement. The Settlement proposed a rate stabilization plan that would limit initial bill increases in 2006 to 21%, with customers participating in the plan unless they opt out. The companies would treat the deferred revenue balances as regulatory assets. These regulatory assets would be recovered during a March 2007 through May 2008 recovery period, with the inclusion of interest on the deferred amounts based on the utilities actual short-term carrying costs.

After objections from the Office of Public Counsel, a revised Settlement was reached and filed with the commission to implement a modified Residential Electric Rate Mitigation Program (Program) commencing June 1, 2006, which would limit rate increases to a monthly increase of 15% from June 1, 2006, to February 28, 2007. An additional 15.7% increase would be added for the period March 1, 2007, to May 31, 2007, and full market rates would be charged beginning June 1, 2007.

The deferred amounts (from June 1 2006 to May 31, 2007) would be collected in the form of a nonbypassable charge effective June 1, 2007, with recovery over an 18-month period from customers participating in the plan. The deferred balances would accrue actual carrying costs, but these carrying costs would be offset by the return received by Pepco or Delmarva for providing Standard Offer Service to residential customers, and with a one-year true-up at the end of the recovery period. The Revised Agreement
further provides that customers who wish to participate must affirmatively choose to opt-in to the program. The commission accepted this revised Settlement.

b. Timing of Rate Increases to Mitigate Rate Impacts

New York PSC – Niagara Mohawk (dba National Grid) CTC Recovery Extension

Decision N/A Filed 1/29/10 Case 10-E-0050

National Grid filed a three-year rate plan asking for a $390 million rate increase – but combined the requested increase with both a proposed phase-in and other reductions so that customer bills do not increase. To achieve this result, National Grid proposed to extend the amortization schedule for its Competitive Transition Charges (CTC) to offset the aggregate increase in delivery revenue. Assuming no extension of the amortization schedule, the company’s proposal would equate to an increase in electric revenues by $391 million for 2011 (a 12.15% increase in aggregate revenues), an additional $32 million (total of $423 million) for 2012, with a reduction in revenues of $31 million (total of $392 million) for 2013. The commission has not yet acted on the company’s proposal.

South Carolina PUC – South Carolina Electric & Gas (SCEG) Rate Increase Phase-in

Decided N/A Filed 1/15/10 Case 2009-489-E

SCEG filed an application seeking a $197.6 million, 9.52% base rate increase. In announcing the request, SCEG President Kevin Marsh said the utility was proposing to phase in the increase to limit the impact on customers. Marsh stated, “Recognizing the financial challenge that this increase will represent for many of our customers, we've asked the commission to phase in this increase in three stages over the next 18 months.” If approved, residential customers would see a 3.19% increase on their bills beginning July 15, 2010, followed by a 3.06% increase Jan. 1, 2011, and a 3.27% increase July 1, 2011. The commission has not yet acted on this filing.

Idaho PUC – Idaho Power (IP) Acceleration of Power Cost Adjustment Reductions

Decided 1/13/10 Filed 11/6/09 Case IPC-E-09-30

IP filed a Stipulation based on an agreement reached with several parties proposing several measures to mitigate potential future rate increases. Specifically, the company proposed that some of the reduction in the Power Cost Adjustment (PCA) surcharge that customers would otherwise get in June 2010 be used to reduce base rates. The Stipulation provides that the first $40 million of the anticipated 2010 PCA reduction would be allocated equally between customers and the company. The company’s share of this PCA rate reduction would be applied to increase permanent base rates on a uniform percentage basis to all customers. The customers' share of this PCA rate reduction would be a direct customer rate reduction, as would all PCA rate reductions between $40 million and $60 million. A PCA rate reduction in excess of $60 million would be applied to absorb any increase in the base level for net power supply expenses. If the 2010 PCA rate reduction exceeds $60 million, plus the established increase in base net power supply expenses, the next $10 million would be shared equally between the company and its customers and any remainder would go entirely to customers.

The Stipulation also allows the company to accelerate the use of the customer share of tax credits the company receives on its capital investments. Typically, the customer portion of the tax benefit is credited over the lifetime of the investment. Under the Stipulation, IP would use the investment credit during later
years to improve its earnings rather than asking for a rate increase. The agreement limits the amount of the investment tax credit that can be accelerated to $45 million over three years.

The Stipulation also provides that Idaho Power will not file a general rate case to change its revenue requirement and resulting rates prior to January 1, 2012. The rate case moratorium does not affect other revenue requirement proceedings, such as the PCA, the fixed cost adjustment (FCA), an annual advanced metering infrastructure rate adjustment, an annual pension expense recovery, or the energy efficiency rider adjustment.

The Stipulation was approved by the Idaho Public Utilities Commission.

Virginia SCC – Dominion Virginia Power (DVP) Rate Case and Fuel Cost Recovery Case
Decided 12/16/09 Filed 3/31/09 Cases PUE-2009-00011, 00016 and 00017
In March 2009, DVP simultaneously filed requests for two riders to recover the costs associated with construction of two generating plants (PUE-2009-0011 and PUE-2009-0017), and a reduction in its fuel adjustment clause charges (PUE-2009-0016). Rider S had been approved previously to recover the costs of a coal-fired plant in Wise County, VA. The company requested an adjustment in Rider S that would generate $174.433 million in revenue over 12 months. Rider R is a new surcharge that allows recovery of the costs of financing construction of Bear Garden natural gas-fired power plant in Buckingham County. This surcharge will generate $73.355 million in revenue over 12 months. The fuel cost reduction would result in an overall decrease of $119.2 million for the period January 1, 2010, to June 30, 2010.

Both the Riders and the fuel cost reduction were proposed to have an effective date of January 1, 2010. For a residential customer using 1,000 kilowatt-hours of electricity, Rider R would add $1.33 to the typical monthly bill and Rider S adds $1.63, for a total increase of $2.96. The rate increases due to Rider R and Rider S are tempered by a reduction of approximately $3.83 on a typical monthly bill for the same customer using 1,000 kWh of electricity for the six month period the fuel cost decrease is in effect. The Virginia State Corporation Commission approved the effective dates and amounts proposed on December 16, 2009.

Minnesota PUC – Minnesota Power Rate Increase Request
Decided 12/15/09 Filed 11/2/09 Case E-015/GR-09-1151
Minnesota Power requested a base rate increase of $81 million plus a conversion of several riders into base rates amounting to $14 million, citing a robust construction program and the economic condition of its service area as necessitating the increase. The filing also requested an interim rate increase of $73 million to take effect while the permanent rate increase was considered. In its filing for interim rates, the company proposed:

- lower allowed returns (8.45%) for interim rates
- use of the company’s proposed lower depreciation rates for interim rates, reflecting a soon-to-be-filed depreciation petition, instead of using the depreciation expense in the currently effective order from the company’s most recent depreciation docket
- setting asset-based wholesale margins for interim rates using amounts based on contractual commitments and forecasts, rather than on the four-year average method directed in the company’s last rate case
In an initial Order, the Minnesota Public Utilities Commission set the larger permanent rate increase for hearing, but approved a smaller interim rate increase of $48 million, or 60% of the company’s requested final rate increase of $81 million, to take effect on January 1, 2010. The commission cited several “exigent circumstances” in Minnesota Power’s service area for reducing the allowable interim rate increase. Among these cited exigent circumstances were:

- the unprecedented size of the requested rate increase
- the timing of the rate increase, immediately after a previously requested rate increase went into effect
- the severe national and local recession
- potential rate shock and economic harm to the company’s customers.

The reduced interim rate will mean that the company’s proposed rate increase, if ultimately approved, will be phased in.

Wisconsin PSC – Northern States Power-WI (aka Xcel Energy) Rate Increase Mitigation

Decided 12/10/09    Filed 6/1/2009    Cases 4220-UR-116, 4220-FR-103

The commission approved a $6.4 million rate increase request for Xcel’s retail electric operations, amounting to a 2.1% increase. At the same time, the commission ordered that a portion of the 2009 fuel cost-related refund be used to offset the $6.4 million electric rate increase “in recognition of the difficult economic times.” The fuel-cost reductions were expected to bring the overall rate impact to customers to zero on average, although some customers would see increases and some decreases under the commission decision.

Texas PUC – El Paso Electric Rate Increase and Fuel Charge Reduction

Decided N/A    Filed 10/9/09    Case 37690

El Paso Electric filed for a rate increase of $51.6 million or an increase of 9.3% for all customers. According to the company’s filing, the rate increase request would bring an 11%, or $6.69 a month, increase for the average El Paso residential customer. However, the company also projected a $12.3 million in reduced annual fuel charges to customers in its filing tied to increased profit sharing. (In 2006, El Paso Electric agreed to increase the amount of profits shared with customers for off-system electric sales from 25% to 90% beginning in July 2010). Those profits reduce fuel charges to customers, and lower the projected rate increase to an average 9.6% for residential customers. The Public Utilities Commission of Texas has not issued a decision in the docket.

North Carolina UC – Duke Energy Rate Increase Phase-in

Decided 12/7/09    Filed 6/2/09    Case E-7, Sub 909

In a Settlement Agreement approved by the North Carolina Utilities Commission, Duke Energy agreed to phase in a proposed $315 million rate increase over a two-year period beginning on January 1, 2010. Additional provisions of the Settlement lower the total impact of the increase to customer bills to approximately 7%. With the two year phase in, the average increase to customers’ bills would be 3.8% effective Jan. 1, 2010, with an additional 3.2% increase to become effective Jan. 1, 2011. Duke Energy recognized the challenging economic climate as a rationale for the phase in of the rate increases.
New York PSC – Consolidated Edison Co. of New York (ConEd) Rate Case Including Mitigation Measures

Decided N/A Filed 5/8/09 Case 09-00836

The company proposed a three-year levelized rate plan for its electric operations, which, if adopted, would establish rates for the three-year period ending March 31, 2013. Under the proposal, the requested rate increases to take effect on April 1, 2010, 2011 and 2012, respectively, would be moderated to 6% annually on a total bill basis. ConEd noted that it also filed single Rate Year tariffs, as required, for the 12 months ending March 31, 2011, in the event the three-year plan is not adopted. The proposed increases for the one-year period only would result in a 7.4% increase on a total bill basis, inclusive of projected supply costs and gross receipts taxes, based on the estimated level of sales for the period. This is an ongoing proceeding.

Oklahoma CC – Oklahoma Gas and Electric (OG&E) Rate Request

Decided 7/24/09 Filed 2/27/09 Case PUD 200800398

OG&E requested a rate increase of $110.3 million in this case. In a Settlement Agreement approved by the commission, a rate increase of $48.3 million was allowed. Under the Stipulation, a plan to mitigate this rate increase was put in place. Under the terms of a previously ordered rate reduction (Joint Stipulation Cause No. PUD 00800398 – Final Order Approving Joint Stipulation and Settlement Agreement), OG&E was required to file new Fuel Cost Adjustment factors that would reduce customer fuel costs approximately $137.9 million in total, or $48.2 million to the residential class, over a 12-month period. Under the terms of this Stipulated Agreement, the residential class would receive a $44.3 million annual increase offset by a $48.2 million reduction in fuel costs, resulting in a net decrease to the class of $3.9 million during the first 12 months that the new rates are in place.

Nevada PSC – Nevada Power (NP) Rate Phase-in

Decided 6/24/09 Filed 12/1/08 Case 08-12002

In its filing, NP made three proposals to mitigate the impact of its proposed rate increase of $323.9 million on customers in recognition of the economic circumstances of its service area. The company proposed to delay implementation of the increase until after the hottest summer months (subject to the commission agreeing to regulatory asset accounting treatment of the deferred cost and ultimate recovery including carrying charges), recovery of demand-side management costs over a six-year, rather than a three-year, period, and establishment of a low-income residential customer discount rate. The company also emphasized that expected upcoming fuel cost decreases would significantly reduce the impact of the proposed rate increase. NP proposed that reductions to its fuel and energy charges (its Base Tariff Energy Rate or BTER) be made effective at the same time as the rate increase, which involves moving up the anticipated BTER decreases by six months.

In its final Order, the Nevada Public Utilities Commission took several steps to mitigate rate impacts and modified NP’s proposals. First, it established a Subsidy Mitigation Adjustment to coincide with the expected BTER reductions that would move a portion of the costs (capped at 3%) that are incurred by residential customers but borne by non-residential customers back to residential customers. Second, the commission required that the allowed increase (which was $217 million – significantly less than the request) be phased in, with an initial increase of about 3% on July 1, 2009, and an additional increase of about 3.8% on January 1, 2010. The commission did allow for recovery of carrying charges on the deferred balance at the utility’s allowed return. The commission accepted NP’s proposal to amortize demand-side management costs over six years but denied the special low-income rate proposal.
New Mexico PRC – Public Service Co. of New Mexico (PNM) Rate Phase-in
Decided 6/1/09 Filed 9/22/08 Case 08-00273-UT

PNM requested a rate increase of $123.3 million, consisting of $111 million in non-fuel increases and $12.3 million in fuel cost increases. The parties to the case entered into a Stipulation to settle the case that included several rate impact mitigation measures. The primary measure (aside from reducing the amount of the increase) adopted in the Stipulation was to implement the rate increase in two phases, with 35% of the increase deferred until April 21, 2010, and without recovery of carrying charges on the deferred increase. The Stipulation also requires PNM to credit 100% of its off-system sales margins, rather than 75% as proposed in PNM’s filing. The result is an initial rate increase to residential customers of 9.7% rather than the 23.4% proposed by PNM. The Stipulation was accepted by the New Mexico Public Regulation Commission, with some modifications primarily to rate design.

Idaho PUC – Avista Extension of Power Cost Adjustment
Decided 10/3/05 Filed 8/11/05 Case AVU-E-05-6

Avista Corp. filed a request to extend its existing Power Cost Adjustment (PCA) surcharge that allows the company to recover above normal costs of supplying power to its customers. In October 2001 the commission approved a 19.4% PCA surcharge to enable the company to pay down a $78 million power cost debt incurred during the 2000-01 western power crises. The company requested, and the commission approved, the one-year extension to the PCA surcharge to further reduce the power cost deferral balance and ensure that customers do not experience any increase in existing rates.

Massachusetts DPU – NSTAR Rate Phase-in
Decided 12/30/05 Filed 12/6/05 Case 05-85

NSTAR Electric and NSTAR Gas in 2005 indicated their plan to file in October 2005 for general rate increases totaling $89 million to take effect in 2006. Instead, at the request of the Massachusetts attorney general, the companies entered into Settlement negotiations to pursue alternative ways to provide them with sufficient revenues while mitigating rate impacts to customers to the extent practicable. In December 2005, NSTAR filed a proposed Settlement agreement that was approved by the Massachusetts Department of Public Utilities.

The Settlement agreement provides for an Alternative Rate Stabilization Plan that specified a reduction in the rates that NSTAR electric customers pay for distribution service and transition charges (NSTAR was previously allowed to recover transition costs due to introduction of retail competition in Massachusetts), and then to stabilize those charges over a seven-year period. Transition charges were reduced by $20 million below previously proposed rates, distribution charges were increased, and overall rates were frozen for the seven years. The overall impact was to reduce rates in the early years of the seven-year plan and allow recovery of the costs of those reductions in later years when transition cost recovery would otherwise have ended, and rates otherwise might have been reduced, but for the rate freeze.
c. Securitization Cases

**Maryland PSC – Baltimore Gas and Electric Deferred Cost Securitization**

Decided 12/28/06      Filed 11/3/06    Case 9089

Following enactment of SB 1 by the Maryland legislature on June 23, 2006, the Maryland Public Service Commission issued an irrevocable qualified rate order (QRO) authorizing securitization and recovery of deferred costs from the legislated phase-in of a previously approved 72% residential rate increase. The QRO approves issuance of an estimated $630 million in bonds to securitize the deferred costs from this phase-in. The order also requires the balance of power supply costs above the phase-in cap to be recorded as a regulatory asset and deferred for recovery over the bond term of up to 12 years. The QRO obligates residential customers served by BGE or retail suppliers in company service territory to pay nonbypassable customer surcharges to repay the principal, interest, and related costs on the bonds. The order also approved a company-requested adjustment of charges to be collected to account for: (1) temporary federal and state income tax savings; (2) differences in timing between bond issuance and completion of the phase-in deferral period; (3) over- and under-recovery of phase-in costs; and, (4) other miscellaneous credits.

**Mississippi PSC – Entergy Mississippi and Mississippi Power Storm Recovery**

Entergy – MS

Decided 6/28/06      Filed 2/27/06    Case 2006-UA-82

Mississippi Power

Decided 6/28/06      Filed 9/25/05    Case 2005-UA-0555

Entergy and Mississippi Power petitioned the Mississippi Public Service Commission for the issuance of financing orders and authorization to increase storm damage reserves. The financing orders were to authorize the State Bond Commission to issue System Restoration Bonds to finance the costs associated with restoring electric utility systems and funding the utilities’ storm damage reserves at adequate levels. In addition, Mississippi Power requested, in its financing order petition, securitization financing for a proposed new storm operations facility and office annex. Both companies were to be hardened to withstand hurricane force winds at their locations approximately 10 miles inland from potential flooding. The final PSC Order approves recovery of $89.2 million in Hurricane Katrina-related restoration costs for Entergy and $302.4 million for Mississippi Power, subject to reduction by amounts recovered through Community Development Block Grants or other sources. The PSC required the companies to mitigate the impact on customers by securitizing these costs pursuant to the Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act (the “Securitization Act”) enacted in 2006.

On May 31, 2007, the Mississippi Development Bank issued $55 million in Taxable Special Obligation Bonds for the benefit of Entergy-MS and $150 million for Mississippi Power. The bond debt service is being repaid through system restoration charges that are to be reset by the companies annually to generate 110% of the required annual debt service. System restoration charges will be applied to all customers receiving service from the companies. The system restoration charge does not provide revenue to the utilities.

**Texas PUC – American Electric Power Texas Central (AEP) Transition Bonds**

Decided 6/21/06      Filed 3/3/06    Case 32475

AEP requested approval for the issuance of $1.80 billion in transition bonds to recover upfront costs and stranded costs of generation associated with industry restructuring in Texas and related carrying costs. Cost
recovery had previously been approved by the Texas PUC (Case 31056). Following a settlement agreement, the PUC approved issuance of $1.72 billion of 14-year transition bonds. Citing company analyses based on their initial request, the PUC found that economic benefits to ratepayers would be $365 million to $710 million on a present value basis, increasing to $966 million using an expected weighted-average annual interest rate of 5.218%.

**Florida PSC – Florida Power & Light (FPL) Storm Recovery**

Decided 5/30/06  Filed 1/13/06  Case 060038-EI

In response to a request for storm-related recovery costs of FPL after a series of devastating hurricanes (Dennis, Katrina, Wilma, and Rita) in 2005, the Florida PSC found that the issuance of storm recovery bonds, backed by a customer surcharge – as authorized by the Florida legislature in 2005 (Section 366.8260, Florida Statutes) – would be the best way to mitigate rate impacts. FPL requested authorization to issue $1.05 billion in storm recovery bonds, which was needed to enable FPL to: (1) recover the remaining unrecovered balance of its 2004 storm-recovery costs; (2) recover its prudently incurred 2005 storm-recovery costs, less capital costs and insurance proceeds; (3) replenish its storm-recovery reserve; and (4) recover issuance costs associated with the storm-recovery bonds. FPL also proposed that if market rates rise to such an extent that the initial customer charge associated with the proposed current storm-recovery bond issuance exceeded the average retail charge associated with the 2004 storm surcharge already in effect, that the aggregate amount of the storm-recovery bond issuance would be reduced to an amount whereby the initial average charge would not exceed the existing 2004 storm surcharge.

The PSC authorized FPL to issue storm recovery bonds in the amount of $708 million backed by a customer surcharge to be recovered over approximately 12 years, and approved FPL’s proposed mechanism to ensure that the initial customer surcharge would not exceed the level of the existing 2004 surcharge. In approving the bond issuance, the PSC found that “the issuance of the storm-recovery bonds and the imposition of the storm-recovery charges authorized by this Order are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative, more traditional methods of financing or recovering storm-recovery costs and replenishing the Reserve.” The PSC also found that “the structuring, marketing, pricing, and financing costs of the storm-recovery bonds are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative methods of financing or recovering storm-recovery costs and replenishing the Reserve.”

**West Virginia PSC – Allegheny Energy Environmental Control Bonds**

Decided 4/7/06  Filed 3/24/05  Case 05-0402-E-CN

Monongahela Power and Potomac Edison (subsidiaries of Allegheny Energy) requested authorization to issue $38 million in environmental control bonds under West Virginia Code §24-2-4e. The bonds were to be used to finance the installation of scrubbers at the companies’ Fort Martin coal-fired power plant. The Applicants concluded that using securitization financing “is both the lowest cost solution, and also the most attractive compliance option under all direct and indirect measures assessed, including: cost per SO2 ton removed, customer impact, emission levels, the addition of construction and operating jobs at Ft. Martin, and preservation of employment in the mining industry. The commission approved the request, which was later amended by joint stipulation to accelerate issuance to take advantage of lower interest costs and to avoid the risk of further escalation in project costs. The commission also established the necessary customer surcharges and true-up mechanisms to ensure repayment of the environmental control bonds.
Texas PUC – CenterPoint Energy Storm Recovery Costs
Decided 8/26/09     Filed 8/8/09     Case 37200

The Public Utility Commission of Texas approved CenterPoint Energy Houston Electric’s request to securitize storm costs resulting from Hurricane Ike in 2008. The commission Order allows $642.8 million of distribution system-related costs to be securitized, based on a Settlement Agreement reached by parties to the case. An additional $20 million for transmission costs was allowed but must be recovered though ERCOT’s transmission cost-of-service mechanism and not through retail rates. The commission also provided for securitization of carrying costs, to be accrued at 11.075% (CenterPoint Houston’s average weighted cost of capital) and required reduction of the final amount by any insurance proceeds, government grants, or other sources of funding reducing CenterPoint’s total costs. In approving the request, the commission noted the company’s finding that the securitization would result in a reduction in costs of $348 million compared to conventional financing mechanisms that would otherwise be used to recover the same level of costs.

d. Rate Design Changes to Mitigate Rate Increases

Illinois CC – Commonwealth Edison Rate Design
Decided 10/11/07     Case 07-0166

In a proceeding initiated on its own motion, the Illinois Commerce Commission reviewed ComEd’s rate design. The proceeding was initiated based on the commission’s belief that significant rate increases approved by the commission that became effective in January 2007 were being unevenly distributed among customer classes. For residential customers, the largest increases occurred on the winter bills of space heating customers, creating a significant hardship for a number of customers. A number of smaller non-residential customers also incurred significant increases in their bills.

With respect to electric space heating customers, the commission found that while it generally desires to establish rates reflective of costs, the need to protect residential customers who face adverse bill impacts is more pressing and takes precedence. The commission adopted a staff proposal to increase summer rates and lower winter rates for residential space heating customers, beginning with the December 2007 billing period. The commission also found that the costs that would have otherwise been reflected in the charges currently in effect for the December 2007 through May 2008 billing periods may be reflected in the supply charges to be established for these customers for the June 2008 through September 2008 billing periods.

With respect to certain nonresidential customers, the commission did not accept rate design changes proposed by commercial building owners.

Illinois CC – Ameren-IL Rate Design
Decided 10/11/07     Case 07-0165

In a proceeding initiated on its own motion, the Illinois Commerce Commission reviewed Ameren’s rate design. In its initiating Order, the commission asked staff to compare the rates for blocks of electricity usage by residential space-heating customers under rates in existence prior to the expiration of the rate freeze with the rates that took effect on January 2, 2007. The Staff Report indicated that rate increases for residential space heating customers appeared to be substantially higher than the average bills for residential customers as a whole. The commission noted that rate increases in January 2007 for average use space heating customers for the Ameren Illinois utilities ranged from 91% to 151%. The commission also noted that the
previously ordered limit of 20% to average rate increases for the residential class as a whole did not apply to subclasses such as residential space heating customers.

The commission adopted a rate design proposal agreed to by Ameren and commission staff consisting of a combination of a modification to interclass revenue allocations for supply service, and several changes in intra-class rate structures in both the delivery and supply services rates. The changes essentially increase summer rates and decrease winter rates while remaining revenue neutral, and shift some costs from residential customers to small non-residential customers. The commission noted that these proposals “are designed to provide rate relief to those customers who have faced the largest increases, particularly electric space-heating customers, while ensuring that other customer groups are not unduly impacted by these rate mitigation measures.”

The commission also adopted use of a “demand rate limiter” to the delivery service charges paid by those customers in Rate 3 (150 kW to 1,000 kW) and Rate 4 (1,000 kW or more) who consume 20% or less of their annual electricity in summer months. The limiter would cap demand charges for certain intermittent users to ensure that they do not exceed the level of 2 cents per kWh consumed by customers in the class. According to staff, the effect of this rate limiter is to prevent these intermittent users from incurring large bill increases driven by the effect of demand charges in the delivery service component of their bills. Without the limiter, some of these customers, including grain dryers, face disproportionately large increases in their bills due to their relatively low load factor.

**Connecticut DPUC – Connecticut Light & Power (CL&P) Standard Service Rates**

Decided 12/8/06 Cases 03-07-02RE09 and 03-07-01RE06

The Connecticut Department of Public Utility Control had previously approved an overall rate increase to Standard Service customers of approximately 7.7%, which is approximately 1.2% lower than proposed by CL&P due to an adjustment of $30 million to 2007 rates. The purpose of this proceeding was to implement that rate increase. The DPUC Order provides that distribution revenue increases for each rate be achieved by increasing the customer charge. However, for several rate classes, the portion of the distribution rate increase that would have caused the customer charge to increase by more than 10% was allocated to the distribution demand charge rate. The DPUC also approved a CL&P proposal to reduce the allocation of “non-bypassable federally mandated congestion charges” to commercial and industrial classes. The DPUC noted that while it does not advocate moving further away from cost-based rates for the recovery of these costs, CL&P’s proposal is intended to mitigate the overall rate impact to large customers. The Department allowed CL&P to reduce the nonbypassable charge to some rate classes, “given the magnitude of the overall rate increase that is being applied to commercial and C&I [commercial & industrial] customers and the disparity between their increase and the overall company average increase.”

e. Negotiated Mitigation Plans

**Virginia Legislature – Appalachian Power (APCo) Rate Relief**

Enacted 2/24/10 Laws HB 1308 and SB 680

In February 2010, both houses of the Virginia General Assembly passed emergency legislation to suspend an APCo interim 12.8% rate increase that took effect in December 2010. APCo, under state law, was entitled to collect this rate increase until a final decision in the case by the Virginia State Corporation Commission. This legislation was based on an agreement negotiated between AEP (parent of APCo), the legislature and the governor. The legislation also permanently precludes the commission from implementing interim rates.
In signing the legislation, Virginia Governor McDonnell stated:

*I want to thank APCo for being a partner with the legislature to find a short term solution to the immediate problem, while we examine the overall issues associated with the recent steep rate increases more carefully. APCo’s customers include families, small businesses, and industry in Southside, western and southwest Virginia, areas of our state least able to cope with the steep and steady increases in energy costs that have occurred.*

The governor also pledged to work with APCo to find further ways to mitigate rate increases.

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**Illinois Legislature – Commonwealth Edison and Ameren-IL Rate Relief**

Enacted 8/28/07 Law SB 1592

The Illinois Legislature enacted this 2007 law to mitigate already approved rate increases for the customers of ComEd and Ameren that would have resulted in rate increases exceeding an average of 20% – due to expiration of competitive transition rate freezes. The bill places into statute two voluntary agreements reached between Ameren, ComEd, certain generators and the Illinois attorney general – the Escrow Funding Agreement and the Illinois Power Agency Funding Agreement. These Agreements require the utilities to provide $1 billion to fund rate relief for customers of ComEd and Ameren and to fund the Illinois Power Agency Trust Fund established by the Act over a three year period. Both Ameren and ComEd are to provide $488 million in rate relief to residential and certain non-residential customers from 2007 through 2010 through a specified level of bill credits. Remaining funds not credited to customers are to be used for certain targeted programs, which vary by company. The companies also are required to provide $25 million to the IL Power Agency Trust Fund.

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**f. Customer Assistance Programs**

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**Missouri PSC – Kansas City Power & Light (KCPL) Rate Filing**

Decided 6/10/09 Filed 9/5/08 Case ER-2009-0089

KCPL filed for a general rate increase designed to produce an annual increase of $101.5 million in KCPL’s Missouri jurisdictional revenues, which would be a 17.5% increase in revenue. The original filing included a transition cost amortization in the revenue requirement, as ordered by the commission in Case EM-2007-0374. On April 24, 2009, several of the parties to the case filed a stipulated Global Agreement. The Agreement included several mechanisms intended to mitigate the rate impacts of KCPL’s request, including an Economic Relief Pilot Program intended to provide monthly assistance to qualified customers who have trouble paying their electric bills.

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**Illinois CC – Commonwealth Edison Rate Stabilization Plan**

Decided 12/20/06 Filed 5/23/06 Case 06-0411

In this case described in more detail above, the commission “strongly encouraged” ComEd to voluntarily contribute $30 million over the next three years to low-income assistance and senior programs as well as energy efficiency and renewable energy programs – contributions that would not be recovered in rates.
4. Trends and Conclusions

Between 2000 and 2008, there were essentially two kinds of rate increase situations that required the use of special mitigation measures. The first was the need to deal with the significant rate increases that were resulting from the termination of rate caps that were agreed to by utilities and legislatures back in the 1990s for a set period. As the caps were due to come off, customers who had been living with reduced and frozen rates were suddenly faced with a move to much higher market-based prices. To avoid significant rate shock, many state legislatures, regulatory commissions, and the utilities themselves worked out special mitigation plans and programs to ease the transition to market-based rates. In some cases, such as California and the west in 2000 and 2001, mitigation measures were required to deal with special circumstances even before the rate caps were lifted. However, most of these competitive transitions have been completed or are nearing completion, so the number of these cases is dwindling.

The other rate mitigation measure required during this period was securitization of costs associated with recovery from natural disasters – and particularly the several hurricanes that battered the Southeast and Texas in 2004 and 2005. Fortunately, there has not been as much of a need to deal with such extraordinary costs over the past couple of years, so whether the securitization of costs for rate impact mitigation in these cases remains a measure of choice remains to be seen. The role played by securitized mortgage bonds in the recent financial crisis could also have an impact over whether securitization remains a viable and economic mitigation measure.

The newest trend in rate mitigation measures appears to be the use of rate increase phase-ins and in some cases, timing rate increases to coincide with reductions in fuel adjustment clauses or other automatic adjustment mechanisms. The latter may be a temporary phenomenon, taking advantage of a recent downward trend in natural gas prices in particular. But the more general trend of phasing in rate increases over a two- or three-year period to give customers more time to adjust to increased costs (and possibly to wait out the current economic crisis) seems to be a real and perhaps permanent trend. Rate phase-ins are certainly not a panacea – there are carrying charges of deferred increases that create additional costs, and that must be dealt with. The trend may lead to a recurrence of “rate pancaking” that the industry faced in the 1970s and 1980s when new rate increases were requested while existing requests were still being adjudicated.

In any event, the use of rate impact mitigation measures by utilities and state regulators appears to be growing, seemingly bounded only by the creativity of commissions and utility rate analysts. These measures will continue to play an important role in fulfilling the responsibility of regulators to ensure financially healthy electric utilities while at the same time protecting the economic interests of their customers and their states.