Alabama Public Service Commission

Alternative Regulation

The PSC first established a Rate Stabilization and Equalization (RSE) framework for Alabama Power in 1982, and the most recent revisions became effective in 2007. RSE adjustments are based on forward-looking data for the upcoming calendar year. Any annual rate increase is limited to 5%, and rate increases for any two-year period, when averaged, cannot exceed 4% per year. If Alabama Power's projected ROE is outside the allowed ROE range of 13% to 14.5%, rates are to be adjusted, subject to the above limits on rate increases, to establish a 13.75% ROE. If the actual earned ROE was above 14.5%, Alabama Power is to refund to customers the revenues that caused the earned ROE to exceed 14.5%. However, there is no provision for recovering prior-year shortfalls if the earned ROE was below 13%. For the purposes of Rate RSE calculations, Alabama Power has a 45% ceiling on its common equity component of capital.

Separately, in October 2008, the PSC approved a rate package for Alabama Power that specified adjustments to the fixed monthly customer charges of certain customers. Alabama Power was permitted to increase rates by approximately $168 million effective Jan. 1, 2009. Rate RSE was not triggered in 2009 due to the recognition of this additional revenue in the forward-looking RSE calculation.

An RSE framework for Alabama Gas was first established in 1983. The plan has been extended and modified several times. Under the current framework, which is to be in place through 2014, Alabama Gas is authorized an ROE range of 13.15% to 13.65% with an adjusting point of 13.4%. The ROE range may be changed, if the PSC, following a generic rate-of-return hearing, adjusts the equity returns of all major energy utilities operating under a similar regulatory framework. The company has a 55% ceiling on its common equity component of capital. The mechanism also includes a cost-control incentive plan, under which recovery of changes in O&M expenses are subject to caps based on changes in the Consumer Price Index (CPI). If the change in the utility's O&M expenses is within the CPI range (the change in the CPI, plus or minus 0.75 percentage points), no adjustment is made. If the change in O&M expenses exceeds the change in the CPI range, the utility must refund to customers 75% of the difference between the change in O&M expenses and the CPI range. To the extent the change in O&M expenses is less than the change in the CPI range, customers receive one half of the difference through future rate adjustments, and the utility retains the remainder. Non-recurring items and/or recurring items that fluctuate due to factors beyond Alabama Gas' control may be excluded from the cost-control measurement calculation. Annual rate increases under RSE are capped at 4% of the previous year's revenue, and any indicated rate changes, based on a forecasted test year are to be implemented only once per year on Dec. 1. Rate decreases, based on historical results, may be implemented every three months.

An RSE mechanism was implemented for Mobile Gas Service (MGS) in 2002, and is to remain in place until the PSC either rescinds or modifies the framework. MGS' RSE mechanism is similar to Alabama Gas' (see above); however, there are three significant differences: the allowed ROE range for MGS' plan is 13.35%-to-13.85%, with an adjusting point of 13.6%; the cost-control incentive mechanism utilizes the change in the per-customer CPI, plus or minus 1.5 percentage points as its deadband; and, the company has a 60% ceiling on its common equity component of capital. (Section updated 6/24/10)

Arizona Corporation Commission

Alternative Regulation

No data available for the selected commission/section.

Arkansas Public Service Commission

Alternative Regulation

In December 2008, the PSC issued an order providing for Entergy Arkansas to be subject to an earnings review in the context of its storm damage rider (see the Adjustment Clauses section), such that any "over-earnings" realized by the company in 2008 would be used to offset the company's then-unrecovered storm cost balance and credited to ratepayers through the rider. In a mid-2009 filing with the PSC, EA stated that it had a revenue deficiency for 2008, and therefore no adjustment for overearnings was made.

In early-2009, the Arkansas Attorney General (AG) and the PSC Staff filed comments in a proceeding in which the PSC is considering potential "innovative approaches to utility regulation," including the possible use of formula rate plans. At that time, the AG opined that the PSC's existing ratemaking structure does not require significant modifications. The Staff noted that it generally supports continued use of a traditional ratemaking approach. (Section updated 11/2/10)

California Public Utilities Commission

Alternative Regulation

In August 2008, the PUC adopted multi-year (2008 through 2011) settlements in 2008-test-year rate cases for San Diego Gas & Electric (SDG&E) and Southern California Gas (SCG). The settlements establish performance based ratemaking (PBR) frameworks that provide for specific rate increases in each year, and do not contain any earnings caps or sharing provisions (see the 8/13/08 and 8/22/08 Final Reports). These frameworks replace mechanisms that were in place from 2005 through 2007 which included inflation indexing of base rate revenues. In addition, the previous mechanisms included various levels of stockholder/ratepayer sharing if utility base-rate earnings exceeded the PUC authorized overall rate of return by at least 50 basis points.

In May 2008, the PUC adopted an automatic cost-of-capital (COC) mechanism for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and SDG&E under which authorized equity returns are reviewed annually and, if changes in utility bond yields exceed certain levels, are adjusted. SCG has been operating under a similar COC mechanism since the late-1990's (see the Return on Equity section).

For their local gas distribution service, PG&E, SDG&E, and SCG are each subject to a Biennial Cost Allocation Proceeding (BCAP). Depending on the level of gas throughput, PG&E is at risk for recovery of 25% of its distribution revenue requirement associated with non-core customers. SDG&E and SCG are not currently at risk for either its core or non-core transportation revenues. The BCAP determines the authorized methodologies for allocation of costs to customer classes, customer rate designs, and amortization of balancing account balances (see the Adjustment Clauses section).

SDG&E historically operated under a gas procurement PBR that provided for penalties and rewards to be assessed based upon the utility's performance relative to market standards for gas procurement. As of April 1, 2009, SDG&E and SCG operate under a combined portfolio and are subject to a Gas Cost Incentive Mechanism that provides for gas costs above or below a tolerance band around a benchmark level to be shared by ratepayers and stockholders. The benchmark is the average price of 30 day firm spot supplies in the basins in which SCG purchases natural gas.

On Dec. 16, 2010, the PUC adopted an alternate proposed decision issued by Commission President Michael R. Peevey regarding the true-up of interim awards that the PUC had authorized the state's major energy utilities under its energy efficiency incentive framework for the 2006-2008 evaluation period. As a result of the PUC's decision, the utilities will receive the following additional incentive awards: PG&E, $29.1 million; SCE, $18.6 million; SDG&E, $5.1 million; and, SCG, $9.9 million. These awards, combined with those that the PUC had previously authorized, bring the total awards for the 2006-2008 evaluation period to: PG&E, $104 million; SCE, $69 million; SDG&E, $16.2 million; and, SCG, $17.2 million. These true-ups complete the incentive program for the 2006-2008 period. The PUC's instant decision modified its previous incentive framework by adopting a sharing mechanism that enables the utilities to receive awards equal to 7% of energy efficiency program savings provided that the programs are found to have delivered total savings of at least 85% of the energy efficiency goals (FN 12/23/10).

On April 22, 2010, the PUC authorized PG&E to build, over five years, up to 250 MW of solar photovoltaic (PV) generation facilities (in units of 1-20 MW), and enter into power purchase agreements for an additional 250 MW of PV generation. The PUC established an incentive mechanism that will allow PG&E's shareholders to retain 10% of the savings if the actual average cost of the utility-owned PV generation is less than $3,920 per KW (FN 4/23/10).

On June 25, 2010, the PUC adopted an electric distribution reliability (Cornerstone) improvement program for PG&E, the costs of which are to be recovered through a dedicated account outside of general rate cases. The PUC authorized PG&E to implement electric distribution reliability improvement projects that require $357.4 million of capital expenditures and $9.2 million of O&M expenses for the period 2010 through 2013. Rates are to be based on the adopted cost forecasts with a balancing account to accumulate any difference in revenue requirement based on recorded costs compared to the adopted forecast (FN 7/9/10). (Section updated 2/10/11)

Colorado Public Utilities Commission

Alternative Regulation

From 1997 through 2006, earnings sharing mechanism (ESMs) were in place for Public Service Company of Colorado's (PSCO's) electric operations. The ESMs were adopted for PSCO in the context of PUC merger approvals (see the Merger Activity section).

An electric commodity adjustment (ECA) mechanism is in place for PSCO that contains earnings sharing provisions, whereby PSCO shares with customers margins from generation-based short-term energy trading and proprietary trading (see the Adjustment Clause section). Specifically, generation-based margins that exceed $0.3 million are allocated 80% to ratepayers and 20% to shareholders, while proprietary trading margins that exceed $0.6 million are allocated 80% to shareholders and 20% to ratepayers.

Legislation enacted in 2007 allows for the PUC to permit energy utilities to earn incentives on demand-side management (DSM) investments. Such incentives may include: a premium rate of return on the investments; rapid amortization of the DSM investment; and, utility retention of DSM net benefits. In addition, cost recovery through an adjustment clause is permitted (see the Adjustment Clauses section). In 2008, the PUC adopted a DSM incentive mechanism for PSCO, under which the company may collect $2 million of additional after-tax revenue annually for each year it achieves at least 80% of its DSM goals.

Electric investor-owned utilities are permitted to earn rate of return premiums on eligible renewable energy resource investments that provide "net economic benefits" to customers. For these investments, the utility would be entitled to a return bonus equal to as much as 50% of the net economic benefits, provided that the utility complies with the PUC's rules implementing the renewable portfolio standards (see the Renewable Energy section).

In 2008, the PUC opened a generic investigation to review regulatory and rate incentives provided electric and gas utilities under the current regulatory structure. A workshop was held in November 2008. The proceeding is ongoing.

In 2007, the PUC adopted a settlement for Atmos Energy that established an earnings sharing mechanism (ESM) that was in place for 2007 only. The ESM provided for Atmos to retain: 75% of earnings between a 10.25% to 11.25% ROE; 50% of earnings between an 11.25% to 12.25% ROE; 35% of earnings between a 12.25% and 13.25% ROE; and, 25% of earnings above a 13.25% ROE. (Section updated 6/14/10)

Connecticut Department of Public Utility

Alternative Regulation

By law, the DPUC may approve performance-based-regulation (PBR) plans for energy utilities. We note that the existence of an earnings sharing mechanism (ESM) does not negate the need for a four-year rate review, but a periodic review by the DPUC of a utility operating under a qualified PBR plan may serve in lieu of the otherwise-mandated four-year rate review. All of the state's energy utilities either have an ESM in place or have operated under one in the past.

Since 2003, Connecticut Light & Power (CL&P) has operated under an ESM, whereby earnings in excess of a benchmark return on equity (ROE) are shared equally with ratepayers. The disposition of any shared earnings is to be determined by the Department. The current benchmark ROE is 9.4%. For many years, United Illuminating (UI) has operated under an ESM. Under the company's current ESM, UI retains 50% of earnings in excess of the authorized ROE (now 8.75%); the ratepayer portion is returned via bill surcredit.

In accordance with state law, during calendar-years 2004, 2005, and 2006, electric transitional standard offer (TSO) service was available to customers who did not choose a competitive supplier. The law provided for a utility to receive a fee of 0.025¢ per KWH, if the utility was able to procure power at a cost below the regional average cost of power. However, the DPUC has not permitted this incentive to be implemented.

The DPUC may approve incentives to encourage the construction of generation and conservation and load management (C&LM) initiatives intended to reduce federally mandated congestion charges (FMCC). Utilities receive an incentive of $25 KW/year for measures that reduce FMCCs. Incentive costs are recovered through the FMCC rate component on customers' bills. In addition, for several years, CL&P and UI have been earning incentives on CL&M initiatives if certain energy and demand savings targets are met.

Under state law, utilities are also permitted to earn one-time incentives for generation installed in their service territories. Distribution companies were permitted to earn $200/kW in 2006 and 2007 as one-time incentives for customer-sited distributed generation, when such units become operational. For 2008, the incentive was $150/KW for distributed generation. For 2009, the incentive was $100/KW, and for 2010 and thereafter the incentive is $50/KW. As legislatively mandated, in 2008, the DPUC issued a report to the Connecticut General Assembly in which it concluded that "it is not yet feasible to develop a financial incentive program to encourage the state's electric distribution companies to stabilize or to reduce the state's peak electric demand."

Southern Connecticut Gas (SCG) and Connecticut Natural Gas (CNG) operated under multi-year incentive rate plans that contained ESMs from November 2000-September 2005, and May 2001-September 2005, respectively. The companies are now subject to traditional regulation. In 2007, the DPUC adopted a settlement for Yankee Gas Service (YGS) containing a hard earnings cap, whereby all earnings above a 10.1% ROE are to be returned to ratepayers.

The DPUC has approved mechanisms for local gas distribution companies, whereby interruptible sales margins above target levels are shared by firm customers and shareholders. (Section updated 7/13/10)

Delaware Public Service Commission

Alternative Regulation
Delmarva Power & Light's gas division is permitted to retain 20% of the margins associated with non-firm gas sales and transportation service, after the first $3 million of such margin is credited to ratepayers, and 20% of the margins associated with off-system sales and capacity release. (Section updated 11/29/10)

District of Columbia Public Se

Alternative Regulation
There are no alternative regulation plans currently in place for energy utilities in the District. However, Potomac Electric Power's (Pepco's) electric distribution rates for non-low-income customers were capped from January 2001 through August 2007, with no specified earnings restrictions. From January 2001-February 2005, Pepco was permitted to retain a portion of any profits, above a benchmark level, associated with its procurement of power to serve electric customers who declined to select an alternative generation supplier (see the Electric Regulatory Reform/Industry Restructuring section).

In the context of a base rate case decided in 2007, Washington Gas (WG) had sought PSC approval of a performance-based ratemaking (PBR) plan, under which rates would have been frozen for a three-year period during which WG would have been subject to an earnings-sharing mechanism (ESM). However as per a settlement that was ultimately approved by the PSC, WG withdrew the PBR plan. WG may not file for a base rate change prior to Jan. 1, 2011, and new rates may not become effective prior to Oct. 1, 2011. There are no explicit earnings restrictions during this period. (Section updated 9/9/10)

Florida Public Service Commission

Alternative Regulation
Included in the fuel adjustment clause is a generating performance incentive factor. Additionally, in certain instances the PSC allows the companies to retain 20% of the profits from economy energy sales (see the Adjustment Clauses section).

On June 1, 2010, the PSC unanimously approved a settlement, thereby resolving a number of issues pertaining to Florida Power (FP). Under the approved settlement, FP's base rates are to be frozen through December 2012. All parties to the settlement are prohibited from initiating a base rate case if FP is earning within its currently authorized return-on-equity range of 9.5% to 11.5%. The rate freeze does not apply to adjustment clauses. In addition, the adopted settlement specifies that FP had a total system depreciation reserve balance of $588 million as of Dec. 31, 2009, and provides FP the discretion to reduce its depreciation expense by up to $150 million in 2010, by up to $250 million in 2011, and up to an amount sufficient to eliminate the remaining reserve balance in 2012. There is an annual carryover provision for unused amounts below the yearly caps. The approved settlement also provides FP the flexibility to accelerate the amortization of certain regulatory (pension and tax-related) assets (FN 6/4/10).

On Dec. 14, 2010, the PSC unanimously approved a stipulation regarding motions for reconsideration of the PSC's March 17, 2010 order in Florida Power & Light's (FP&L's) test-year 2010 electric rate case. Under the approved stipulation, FP&L's base rates are to be frozen through 2012. Incremental cost recovery for the combined-cycle, gas-fired West County Unit 3, which is expected to be placed in service in mid-2011, is permitted via the company's capacity cost recovery clause up to the amount of the projected fuel-cost savings for customers beginning upon commercial operation. The adopted stipulation provides for FP&L's authorized mid-point return on equity (ROE) to remain at 10%. If the company's earned ROE were to fall below 9%, FP&L would be permitted to seek a retail base rate increase. If the earned ROE were to exceed 11%, intervenors would be permitted to seek a reduction in the company's base rates. FP&L may, at its discretion, vary the amount of surplus depreciation taken in any calendar year up to a maximum of $267 million (with any unused portion of the yearly maximum permitted to be rolled over to subsequent years), provided its actual ROE remains within a range of 9% to 11%. This provision is intended to enable FP&L to maintain an appropriate earnings level despite the rate freeze. In determining the earned ROE for all purposes under the stipulation, earnings are to be calculated on an actual, non-weather-adjusted basis. FP&L is authorized to use up to a maximum of $776 million in surplus depreciation over the term of the stipulation (FN 12/17/10). (Section updated 1/4/11)

Georgia Public Service Commission

Alternative Regulation

Georgia Power (GP) has been operating under an alternative rate plan (ARP) since 1996. The most recent version of the plan, which was authorized on Dec. 29, 2010, applies to the years 2011 through 2013. GP is not permitted to file a general rate case during the pendency of the ARP unless earnings are projected to fall below a 10.25% ROE. Two-thirds of any earnings above a 12.25% ROE are to be refunded to customers, with the remaining one-third retained by GP. There is no automatic recovery by GP of any earnings shortfall below a 10.25% ROE. If at any time during the term of the ARP, GP projects that its earnings would be lower than a 10.25% ROE for any calendar year, the company may petition the PSC to implement an Interim Cost Recovery (ICR) tariff, which would be utilized to adjust GP's earnings to a 10.25% ROE, in lieu of filing a rate case. Any ICR tariff implemented during the plan would expire at the earlier of Jan. 1, 2014, or the end of the calendar year in which the ICR becomes effective. In any event, the company is required to file a base rate case by July 1, 2013, with any new rates anticipated to be effective Jan. 1, 2014 (FN 12/23/10).

Separately, the PSC has authorized GP to retain 15% of the net present value of the net benefits generated by certain demand-side management programs.

Atlanta Gas Light (ATGL) was subject to a five-year base rate freeze that was initially to expire in April 2010; however, the PSC subsequently approved a request by ATGL to extend the base rate freeze expiration to a date no later than six months following the company's filing of its next base rate case, which occurred on May 3, 2010. There were no earnings restrictions during the freeze.

On Oct. 6, 2009, the PSC approved a Strategic Infrastructure Development and Enhancement (STRIDE) program for ATGL. The STRIDE program authorizes the company to invest about $400 million in infrastructure improvements over the next ten years. Every three years, ATGL is required to file its proposed program for the next three years for PSC review and approval. The costs associated with the program's investment are to be included in base rates each October 1. (Section updated 1/3/11)

Hawaii Public Utilities Comm

Alternative Regulation

On Dec. 29, 2010, the PUC issued an order in Hawaiian Electric Company's (HECO's) 2009-test-year rate case authorizing HECO to implement an alternative regulation framework consisting of a revenue decoupling mechanism, a cost-of-service recovery mechanism (CSRM), and an earnings sharing mechanism (ESM). The decoupling mechanism eliminates the impact on earnings of sales variations, while the CSRM recognizes rate base additions, subject to certain limitations, and variations in operations and maintenance expenses, and depreciation and amortization expenses, between rate cases. Under the ESM, HECO is to allocate earnings such that: incremental earnings during the evaluation period that exceed the company's authorized ROE (as approved by the PUC in the most recent rate case) by up to 100 basis points are to be allocated 75% to shareholders and 25% to ratepayers; incremental earnings between 100 and 300 basis points above the authorized ROE are to be allocated evenly between ratepayers and shareholders; and, incremental earnings in excess of 300 basis points above the authorized ROE are to be allocated 90%/10% to ratepayers and shareholders, respectively. No rate adjustments are to be made if HECO earns below its authorized ROE. Under the mechanisms, rates are to be adjusted annually, with calendar-year evaluation periods. HECO is to tender annual filings each March 31, based on the previous calendar-year, with prospective annual adjustments to be in effect over the subsequent 12 months beginning June 1. While operating under the mechanisms, HECO is to file a general rate case every three years.

In an order issued by the PUC on Aug. 31, 2010, the Commission indicated that it will permit Hawaii Electric Light Company and Maui Electric Company to operate under an alternative regulation framework coincident with the PUC's issuance of an interim or final order in the utilities' pending general rate proceedings (FN 9/3/10). (Section updated 3/21/11)

Idaho Public Utilities Commission

Alternative Regulation
Idaho Power (IP) is operating under an earnings sharing mechanism under which incremental earnings in excess of a 10.5% ROE in any calendar year 2009 to 2011 are to be shared equally by customers and shareholders.

Incentive power cost adjustment mechanisms are in effect for the state's electric utilities. The mechanisms permit the utilities to absorb or retain a portion of energy cost differences from a baseline amount that is reflected in bases rates (see the Adjustment Clauses section).

IP is permitted to retain 5% of the net proceeds related to the sale of surplus SO2 emission allowances. The customer portion of the proceeds is generally distributed through the company's power cost adjustment. Previously, the company retained 10% of SO2 net proceeds. (Section updated 8/27/10)

Illinois Commerce Commission

Alternative Regulation
By law, the ICC may approve alternative regulation plans (ARPs) for energy utilities. However, no ARPs are currently in place.

During the 1998 2006 restructuring-related transition period, electric utility rates were capped at pre-established levels and the utilities were permitted to retain earnings up to ROE caps ranging from 650 to 1,250 basis points above the prevailing two-year average yield on U.S. Treasurys.

From 1992-2002, Northern Illinois Gas operated under an ARP, whereby differences between the actual cost of gas and a market-based index were shared equally with ratepayers. The plan was subsequently terminated due to allegations that the company had manipulated the plan's results (see the Adjustment Clauses section). (Section updated 6/11/10)

Indiana Utility Regulatory Commission

Alternative Regulation
In accordance with state statutes, the utilities are subject to a net operating income (NOI) test in the context of fuel adjustment clause (FAC) and/or gas cost adjustment (GCA) filings, whereby the utility's actual NOI during a given evaluation period is compared to the NOI authorized by the URC in the company's last base rate proceeding. If the company's actual NOI exceeds its authorized NOI, refunds may be required. To the extent any "earnings overages" realized during a given period are offset by cumulative earnings shortfalls from prior periods (e.g., the last five years or the time since the utility's last rate case, whichever is longer), refunds would not be required.

Duke Energy Indiana (DEI) is permitted to retain a portion of the margins associated with off-system sales (OSS). Southern Indiana Gas & Electric (SIGECO) is authorized to share equally with ratepayers wholesale power margins that vary from the $10.5 million level reflected in the company's base rates. Indiana Michigan Power is permitted to equally share with ratepayers OSS margins that exceed a $37.5 million base level of such margins. In an August 2010 rate decision, the URC authorized Northern Indiana Public Service (NIPSCO) to equally share with ratepayers OSS margins above a base level (see the Final Report dated Sept. 22, 2010).

NIPSCO retains/absorbs a portion of gas cost variations that are below/above a benchmark level (see the Adjustment Clauses section), and retains 15% of revenue from capacity release activities. NIPSCO also utilizes a gas energy efficiency program that includes a revenue-sharing mechanism, whereby the company may retain 50% of any incremental revenues in excess of $6 million associated with its "rate simplification" plan (if customer gas usage does not decrease as expected).

DEI is permitted to earn an incentive on investments in certain energy efficiency, conservation, and demand-side management (DSM) programs. Specifically, the company may retain cost savings according to a pre-determined schedule, if program targets are met. DEI is allowed to earn an incentive only on certain "core-plus" DSM programs; however, the company is not permitted to earn an incentive on its "core" DSM programs. Separately, SIGECO is authorized to earn an incentive on certain core-plus DSM programs. (The URC has designated DSM programs that all of the state's utilities are required to implement as "core," and any programs offered in addition the required programs as "core-plus.") (Section updated 4/26/11)

Iowa Utilities Board

Alternative Regulation
Under state law, the IUB is required to adopt ratemaking principles for new baseload facilities greater than 300 MW, combined-cycle plants, alternative energy production facilities prior to construction of the facilities, and certain new projects designed to reduce carbon emissions at existing generation facilities, if such a request is sought by the utility. The IUB is not limited to traditional ratemaking with conventional cost-recovery mechanisms, and may authorize a rate of return on a new facility that is different than the return the utility is permitted to earn on existing generation assets. On March 30, 2010, House File (H.F.) 2399, which would permit the IUB to establish advance ratemaking principles for certain new projects designed to reduce carbon emissions at existing generation facilities, was forwarded to the governor for his signature (see the Legislation section).

Separately, the IUB may award return on equity (ROE) premiums (or impose penalties) on a case-by-case basis related to management efficiency. The IUB has occasionally approved such premiums, although it has not done so in recent years.

Plant Construction Issues--In February 2009, the IUB established a 10.1% ROE for Interstate Power & Light's (IP&L's) investment in the proposed 649-MW, coal-fired Sutherland Generating Station Unit 4 plant. IP&L had proposed to utilize a 12.55% ROE for its investment in the project. IP&L subsequently terminated its plans to proceed with the project for several reasons, including the existing economic and financial climate. Separately, in 2008, the IUB adopted a settlement in a ratemaking-principles proceeding for an IP&L wind project. The approved settlement provides for IP&L to utilize an 11.7% ROE for the 200-MW Whispering Willow Wind Farm, which began commercial operation in December 2009; incorporates an undisclosed per-MW installed cost cap; and, establishes a 25-year depreciable life for the project. In an earlier decision on pre-construction ratemaking principles, the IUB adopted a settlement in 2002 that established a 12.23% ROE for IP&L's investment in the Emery Generating Station, which was completed in 2004.

In pre-construction ratemaking principles decisions issued between 2002-2007, MidAmerican's 540-MW combined-cycle gas plant (Greater Des Moines Energy Center), ultimately completed in 2004, was accorded a 12.23% ROE, and certain company wind generation projects were accorded equity returns that range from 11.7%-12.2%. In addition, the IUB adopted a settlement in 2003 that established ratemaking principles for MidAmerican's investment in a coal-fired generation facility (Council Bluffs Energy Center Unit 4), which was placed into service in 2007. Specifically, construction costs to be included in rate base were capped at $1.125 billion, with a 12.29% ROE; based on its approximate 60% ownership, MidAmerican will be permitted to include in rate base up to $675 million in its next rate proceeding. The total cost of the completed facility was below the approved cap.

In 2008, the IUB adopted a settlement that established pre-construction ratemaking principles to be accorded up to 52.5 MW of wind generation capacity ("Wind VI Iowa Project") to be built by MidAmerican Energy (MidAmerican). These provisions include an 11.7% ROE to be accorded the project after inclusion in rate base and an undisclosed per-MW installed cost cap to apply to MidAmerican's investment in the project (FN 8/29/08). Separately, also in 2008, the IUB adopted a settlement that established pre-construction ratemaking principles for MidAmerican's plan to construct up to 108 MW of incremental wind generation capacity ("Wind V Iowa Projects"). The settlement: specifies an 11.7% ROE to be accorded the project after inclusion in rate base; incorporates an undisclosed per-MW installed cost cap; and, establishes a 20-year depreciable life for the project.

On Nov. 5, 2009, the IUB adopted a settlement in a ratemaking principles proceeding for MidAmerican's proposed "Wind VII Iowa Project," thereby authorizing the company to: utilize a 12.2% ROE for purposes of calculating allowance for funds used during construction (AFUDC), and for its investment in the project upon inclusion in rates; utilize a 20-year depreciable life for the project, which is expected to be completed in multiple stages by year-end 2012; refrain from reflecting the Wind VII project in base rates until 2014, when the base rate moratorium associated with the company's alternative regulation plan (ARP) (see below) concludes; establish a three-tiered cost cap (not disclosed in the filing) for its investment in new wind generation projects completed by Dec. 31, 2009, 2010, and 2012; reserve for the benefit of ratepayers a $2,315 per-MW "contingent revenue-sharing credit" arising from the "bonus tax depreciation" associated with new wind generation as permitted under the federal American Recovery and Reinvestment Act of 2009; retain the Iowa-jurisdictional portion of any federal production tax credits, prospective proceeds from the sale of renewable energy credits and CO2 credits, and wholesale sales revenues associated with the Wind VII project; and, modify its existing ARP, such that if MidAmerican's Iowa-jurisdictional earnings fall below a 10% ROE, the company would be permitted to defer for later recovery the Wind VII proportion of the difference between a 10% ROE and the company's actual ROE.

MidAmerican's electric operations are subject to an ARP that has been extended and modified several times; the current plan is to remain in place through Dec. 31, 2013. Under the plan, MidAmerican is permitted to retain Iowa-jurisdictional earnings up to an 11.75% ROE, 60% of earnings between an 11.75% and a 13% ROE, 50% of earnings between a 13% and a 14% ROE, and 16.67% of earnings above a 14% ROE. Under each scenario, the non-retained portion of incremental earnings is to be accounted for as a regulatory liability and used to offset AFUDC on new gas, coal, or wind-powered generation facilities. If AFUDC is fully offset, the excess is to be utilized to offset depreciation on these facilities, and if depreciation is fully offset, any remaining excess is to be returned to ratepayers. Beginning in 2013, any incremental earnings allocated to ratepayers are to be utilized to offset the Iowa-jurisdictional portion of the investment in new wind projects. MidAmerican is prohibited from requesting a base rate increase to become effective prior to Jan. 1, 2014, unless its ROE falls below 10%.

MidAmerican also operates under a gas procurement incentive plan based on a benchmark "Reference Price," that is established semi-annually. The Reference Price reflects commodity cost indices, storage, and transportation tariffs approved by the Federal Energy Regulatory Commission, and capacity contracts entered into by the company. If actual costs are below 99.75% or above 101.25% of the Reference Price, the associated savings are to be shared equally by ratepayers and MidAmerican, up to a maximum of $0.5 million to MidAmerican.

IP&L and MidAmerican retain 30% of revenue associated with gas capacity release programs and 50% of net gas revenues associated with off system sales. (Section updated 5/26/10)

Kansas Corporation Commission

Alternative Regulation
By law, the KCC can authorize an energy company to earn up to a 200 basis-point ROE premium on investments associated with: the generation of energy from renewable resources; conservation; or, energy efficiency. However, no such premiums have been approved to date.

In certain instances, the KCC has permitted utilities to retain a portion of merger-related savings that exceed the acquisition premium associated with the transaction (see the Corporate Governance and Merger Activity sections).

KCC rules allow the local gas distribution companies to retain a portion of gas cost savings relative to a benchmark, through purchased gas adjustment mechanisms. However, no such proposals have been filed. (See the Adjustment Clauses section.) (Section updated 8/24/10)

Kentucky Public Service Commission

Alternative Regulation
Several of the state's utilities have mechanisms in place that permit sharing by ratepayers and shareholders of off-system sales (OSS) margins.

In a June 2010 PSC-approved rate settlement, Kentucky Power's existing OSS margin-sharing mechanism was revised to reflect a $15.3 million annual base level of such costs (versus the previous $24.9 million base level), with margins that vary from this level to be allocated 60% to ratepayers and 40% to shareholders.

Since 2006, Duke Energy Kentucky (DEK) has been required to flow to ratepayers, through the company's OSS-sharing mechanism, the first $1 million of OSS margins, with margins above $1 million to be shared equally by ratepayers and shareholders.

Columbia Gas of Kentucky (CGK) is authorized to retain one-half of OSS margins and capacity release revenues, and also utilizes a gas-cost incentive mechanism (GCIM) and a gas price-hedging program. The GCIM allows the company to share equally with ratepayers differences between actual gas procurement costs and benchmarked costs. CGK's OSS-sharing mechanism and GCIM are to remain in place through March 31, 2013, and Oct. 31, 2012, respectively.

Louisville Gas & Electric operates under an incentive plan for its gas operations that is to remain in place through Oct. 31, 2015. The plan permits the company to retain one-half of capacity release revenues that exceed a certain threshold. The plan also provides for sharing by ratepayers and shareholders of gas commodity costs, gas transportation costs, and OSS margins that vary from established benchmarks: cost variances of up to 4.5% are allocated 75% to ratepayers and 25% to shareholders; and, variances of 4.5% or more are shared equally.

Atmos Energy operates under an incentive plan that provides for sharing, to varying degrees, by ratepayers and shareholders, of gas commodity costs, gas transportation costs, OSS margins, and capacity release revenues that vary from established benchmarks. Cost variances of up to 2% are allocated 70% to ratepayers and 30% to shareholders; and variances of 2% or more are to be shared equally. The plan is to be in place through May 31, 2011. Gas commodity savings associated with demand-side-management-related usage reductions are shared on an 85%/15% basis by ratepayers and shareholders. Atmos and DEK are also authorized to utilize gas cost hedging programs.

Delta Natural Gas utilizes a conservation/energy efficiency program incentive mechanism that permits the company to retain 15% of the net savings associated with a series of customer gas conservation programs (see the Adjustment Clauses section). (Section updated 12/9/10)

Louisiana Public Service Commission

Alternative Regulation

Entergy Gulf States (EGS)--As part of a plan adopted by the PSC in 1992 for EGS' River Bend Unit 1, a portion of that plant became a "deregulated asset," from which EGS' ratepayers purchase electricity at a rate based upon an assumed annual River Bend capacity factor of 68%. EGS, therefore, benefits to the extent the capacity factor exceeds 68%.

Since 2005, EGS has been subject to an electric formula rate plan (FRP). The FRP has been modified several times. The current plan, which is to be in place through 2012, incorporates a 150-basis-point dead-band around a 10.65% return on equity (ROE) mid-point. If EGS' earned ROE falls below the lower end of the dead-band (9.9%), the company is permitted to prospectively adjust rates to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EGS' earned ROE exceeds the upper end of the dead-band (11.4%), the company is to allocate 60% of the excess to customers. Under the FRP, certain transmission, capacity, environmental compliance, and efficiency costs and "extraordinary cost changes" are accorded different treatment. Future storm costs are to be excluded from recovery through the FRP.

EGS also operates under a gas rate stabilization plan (RSP) that was established in 2005 and includes a 100-basis-point dead-band (10%-11%) around a 10.5% ROE mid-point. The plan includes provisions to adjust rates prospectively, such that: for differences of up to 200 basis points between the earned ROE and the allowed ROE, rates are to be increased or decreased by 50% of the difference necessary to bring the ROE to the (upper or lower) end point of the dead-band; and, for differences greater than 200 basis points above or below the allowed ROE, rates are to be adjusted by 100% of the amount necessary to eliminate the return differential in excess of 200 basis points, plus 50% of the difference between 200 basis points and the end point of the dead-band.

Entergy Louisiana (EL)--The company has operated under an FRP since 2005. The FRP has been modified several times. The current plan, which is to be in place through 2012, includes a 160-basis-point dead-band around a 10.25% ROE mid-point. If EL's earned ROE falls below the lower end of the dead-band (9.45%), the company is permitted to adjust rates prospectively to recover 60% of the shortfall up to the lower end of the dead-band from ratepayers. If EL's earned ROE exceeds the upper end of the dead-band (11.05%), the company is to allocate 60% of the excess earnings to ratepayers. Under the FRP, certain transmission, capacity, environmental compliance, and efficiency costs and "extraordinary cost changes" are accorded different treatment. Future storm costs are to be excluded from recovery through the FRP.

Entergy New Orleans (ENO)--Established as part of a settlement adopted by the New Orleans City Council (NOCC) in April 2009, ENO is to operate under FRPs for its electric and gas operations through 2012. The electric FRP incorporates an 80-basis-point dead-band around an 11.1% ROE mid-point. If ENO's actual electric-related ROE exceeds 11.5%, rates are to be reduced prospectively to reflect the 11.1% mid-point ROE, and if ENO's actual ROE falls below 10.7%, rates are to be increased prospectively to reflect the 11.1% mid-point ROE. In addition, ENO is permitted to earn up to an additional 30-basis-point return for meeting certain customer usage reduction targets associated with its demand side management programs (see the Adjustment Clauses section). This incentive is determined outside of the FRP calculation. The gas FRP incorporates a 100-basis-point dead-band around a 10.75% ROE mid-point. If ENO's actual gas-related ROE exceeds 11.25%, rates are to be reduced prospectively to reflect the 10.75% mid-point ROE, and if ENO's actual ROE is below 10.25%, rates are to be increased prospectively to reflect the 10.75% mid-point ROE. The FRPs permit ENO to seek recovery of "extraordinary cost changes" in certain circumstances.

Cleco Power (Cleco)--On Oct. 14, 2009, the PSC adopted a settlement authorizing Cleco to implement an FRP for a four-year term beginning in 2010. The FRP incorporates a 10.7% ROE benchmark, and provides for: Cleco to retain incremental earnings up to an 11.3% ROE; incremental earnings between an 11.3% and 12.3% ROE to be allocated 40%/60% to shareholders and ratepayers, respectively; and, 100% of incremental earnings in excess of 12.3% to be refunded to ratepayers. The company is to reflect in the FRP certain purchased power capacity costs and the costs associated with certain infrastructure projects. Future storm-related costs are to be excluded from FRP calculations. The FRP also includes an "exceptional changes mechanism," whereby certain rate changes could be made for circumstances beyond the company's control.

Southwestern Electric Power (SWEPCO)--In 2008, the PSC adopted a settlement that provides for SWEPCO to operate under an FRP for a three-year term that includes an ROE dead-band of 10.015%-to-11.115%, such that if SWEPCO's actual ROE were to exceed the upper end of the dead-band, the company would prospectively reduce rates to eliminate 60% of the overage above the upper end of the band, and if the company were to earn an ROE below the lower end of the dead-band, it would be permitted to prospectively increase rates to eliminate 60% of the shortfall up to the lower end of the dead-band. The approved settlement also provides for: SWEPCO to refrain from filing for a base rate increase, and the Staff to refrain from seeking a base rate reduction, during the term of the plan; future "extraordinary increases or decreases in costs" that impact the company's Louisiana-jurisdictional revenue requirement by more than $5 million to be addressed in the annual FRP proceedings; and, a $1.7 million rate reduction to remain in place from August 2008 through August 2011 -- this rate reduction, which is to flow through a separate rider, is to be excluded from annual FRP adjustment calculations. The dead-band and sharing provisions did not apply in the first year of the FRP (Aug. 1, 2008-July 31, 2009), when the company's ROE was set at 10.565%.

In 2008, Cleco, EGS, EL, and SWEPCO filed comments in a proceeding in which the PSC is considering possible fuel cost recovery incentives for the state's electric utilities. These utilities, in general, have reservations regarding fuel cost incentives (FN 3/14/08). The proceeding is pending.

CenterPoint Energy Resources (CER)--The company operates under an RSP that was implemented in 2004, and includes a 100-basis-point dead-band around a 10.25% ROE benchmark, whereby: for earnings between 50 basis points and 200 basis points above or below the authorized ROE, the company is to adjust rates by 50% of the difference necessary to bring the allowed ROE to the end-point of the dead-band; for earnings more than 200 basis points above or below the authorized ROE, rates would be adjusted by 100% of the amount necessary to eliminate the return differential in excess of 200 basis points plus one-half of the difference between 200 basis points and the end-point of the dead-band. CER's RSP is to remain in place until terminated by the PSC.

Louisiana Gas Service (LGS)/TransLouisiana Gas (TLG)--LGS and TLG currently operate under rate stabilization clauses (RSCs) that were established in 2006. The clauses include an authorized 10.4% ROE, and a 10%-to-10.8% ROE dead-band for TLG, with TLG's rates to be adjusted for variations above or below the dead-band. LGS is not subject to a dead-band, and that company's rates are to be adjusted annually by the amount required to achieve a 10.4% ROE.

LGS is also subject to an operations and maintenance (O&M) expense sharing mechanism that was instituted in 2003. Under this mechanism, an O&M benchmark of $39.9 million was established, effective Dec. 31, 2003, and is adjusted annually for changes in inflation and customer levels. The ROE used in the RSC measurement is to be calculated based on the adjusted O&M benchmark. (Section updated 3/1/11)

Maine Public Utilities Commission

Alternative Regulation

Since 1995, with the exception of calendar-year 2008, Central Maine Power (CMP) has operated under an alternative regulation plan (ARP). The most recent plan is to be in effect through Dec. 31, 2013. Under the ARP, annual price changes are to occur July 1 in the years 2009 through 2013, and are to reflect: changes in the Gross Domestic Product-Price Index (GDP-PI), less a 1% productivity offset; increases in mandated costs (that exceed $150,000 individually and exceed $3 million in aggregate in any calendar year); net capital gains and losses; a customer cost-allocation adjustment; storm costs; earnings sharing; and, service quality penalties, if applicable. The ARP contains an earnings sharing mechanism, under which 50% of earnings above an 11% return on equity are to be allocated to CMP and 50% to system improvements/customer benefits. The plan provides for CMP to use a 10.9% pre-tax weighted average cost of capital to calculate carrying costs on deferred regulatory assets or liabilities and the return on distribution rate base. The ARP also includes a service quality penalty of up to $5 million in any year if service levels fall below established baselines. Under the plan, mandated costs are defined as those that result from a force majeure event or ongoing costs that result from accounting, federal or state legislation, regulatory, or tax changes. There is to be a review of CMP's customer service and reliability performance in 2011.

Bangor Hydro-Electric (BHE) operated under a distribution-only ARP from 2002 through 2007. The plan provided for base rate reductions of: 2.5% on July 1, 2003; 2.75% on July 1, 2004; no greater than 2.75% on July 1, 2005, calculated by averaging the annual change in the GDP-PI for the two preceding years, less 5.75%; and, no greater than 2% on July 1, 2006 and 2007, equal to the average change in the GDP-PI for the two prior years, less 5%. The annual price changes were adjusted to reflect any: (1) net capital gains and losses; (2) earnings sharing (e.g., a positive amount equal to 50% of any revenue deficiency below a 5% distribution ROE for the prior calendar year, or a negative amount equal to 50% of any revenue surplus above a 17% distribution ROE for the prior calendar year); and, (3) mandated costs. The plan included service reliability and customer service benchmarks, with annual penalties of up to $0.84 million if performance was below the benchmark levels. BHE is now operating under traditional regulation.

Bangor Gas is operating under a multi-year ARP that initially became effective in 1999, and was extended through 2012 in connection with Energy West's 2007 acquisition of Bangor Gas from Sempra Energy. The ARP provides for a rate cap (initially set based on a three-year average of oil prices), with inflation-indexed rate cap increases, pricing flexibility, and authority to enter into special contracts without Commission approval. The plan initially contained a 15% ROE trigger for earnings sharing purposes; however, as part of the PUC's approval of the Energy West acquisition, the PUC raised the trigger for earnings sharing to 30%. Consequently, earnings in excess of a 30% ROE are to be allocated equally between ratepayers and shareholders.

In 1998, when Maine Natural Gas was initially certified by the state to provide natural gas, the company agreed to refrain from filing for a base rate increase for five years in return for "entrepreneurial freedom" to enter into special rate contracts without prior PUC approval. The rate freeze expired March 31, 2004. In 2005, the PUC adopted a settlement providing for a three-year, phase-in rate plan with specified distribution rate increases as follows: 10% effective Nov. 1, 2005; 9% effective Nov. 1, 2006; and, 7% on Nov. 1, 2007. The latter increase was subject to an ROE limitation of 10%. The PUC approved a second three-year phase-in rate plan extending through 2012, with distribution rate increases of 12%, 10%, and 10%, on Jan. 1, 2010, Dec. 1, 2010 and Dec. 1, 2011. The second and third increases are conditioned on need as measured by the company's revenue levels and prior-year financial performance. (Section updated 2/10/11)

Maryland Public Service Commission

Alternative Regulation

Delmarva Power & Light and Potomac Electric Power may earn an incentive if the companies exceed certain demand-side management targets (see the Integrated Resource Planning section). Baltimore Gas & Electric (BGE) and Columbia Gas of Maryland (CGM) are subject to gas cost incentive mechanisms, under which gas costs above or below benchmark levels are shared with ratepayers. CGM is a subsidiary of Columbia Energy Group, which is a subsidiary of NiSource (NI). Off-system sales sharing mechanisms are also in place for BGE, CGM, and Washington Gas (WG). (Section updated 9/29/10)

Massachusetts Dept. of Public Utilities

Alternative Regulation

By statute, electric and gas utilities may be subject to a maximum penalty equal to 2.5% of transmission and distribution revenues for poor service quality (SQ). SQ standards were initially established by the DPU in 2001 for electric and gas distribution companies related to customer service and billing performance, customer satisfaction, restricted work days, and reliability. A utility is subject to penalties if its SQ performance statistics fall outside one standard deviation from its historical benchmark in a given year. Penalties may be offset when data indicate superior performance in other measures. While SQ penalties were initially imposed only on those utilities operating under performance-based regulation and merger-related rate plans, we note that such penalties are now applicable to all utilities operating in the state. For the most part, there have been very few SQ penalties imposed by the DPU. However, one recent penalty of note was an $8 million refund ordered by the DPU for customers of Massachusetts Electric in January 2010 due to the number of power outages and length of such outages in 2006.

In November 2009, the DPU issued an order citing profound SQ failures in Fitchburg Gas and Electric Light's (FG&E)

response to a December 2008 winter storm. While the DPU noted that it has no authority to impose fines for failure to address storm damage, the Department stated that FG&E's performance would warrant consideration of monetary penalties. The Department noted therefore, that FG&E's SQ issues are likely to be considered in the company's next rate case when establishing return on equity and the recovery of costs associated with the storm.

Distribution companies that achieve targeted performance levels for energy efficiency programs may earn an incentive. In accordance with energy efficiency legislation enacted in 2008 (see the Legislation section), the DPU authorized incentives for the state's electric and gas utilities as part of three-year energy efficiency plans that were adopted by the DPU in 2009 (see the Integrated Resource Planning section).

Massachusetts Electric (ME) operated under a merger-related indexed rate plan that was in place through Dec. 31, 2009 (see the Merger Activity section). Currently, ME is operating under an earnings sharing mechanism that was established by the DPU as part of a 2009 rate case decision. Under the mechanism, earnings above a 10.35% ROE are to be shared equally with ratepayers.

NSTAR Electric has been operating under a performance-based regulation (PBR) plan that became effective Jan. 1, 2006, and is to be in effect through Dec. 31, 2012. The PBR contains price-cap and earnings-sharing provisions. Distribution prices are to be adjusted annually based on the change in the Gross Domestic Product-Price Index (GDP PI), less a productivity factor of 0.5% in 2007, 0.55% in 2008, 0.60% in 2009, 0.65% in 2010, 0.70% in 2011, and 0.75% in 2012. Such price changes are to be offset by reductions in the company's transition charges. The plan includes an earnings sharing mechanism (ESM) for electric distribution service that provides for earnings outside of an 8.5%-to-12.5% return on equity (ROE) range to be shared equally with ratepayers. If NSTAR Electric's annual aggregate ROE exceeds 13.5%, the Attorney General (AG) may request that a general rate investigation be initiated. Similarly, if NSTAR Electric's ROE falls below 7.5%, the company may file a request for a general rate increase. As part of the plan, NSTAR may earn incentives tied to successful efforts to reduce transmission constraints and inefficiencies in the wholesale market. Specifically, NSTAR is to retain 25% of the benefits associated with successful customer savings initiatives (CSI). Incentive-related revenue is to be capped at $20 million for NSTAR annually.

In 2006, NSTAR Electric submitted its first CSI filing to the DPU seeking roughly $34 million of "incentive revenue" over the three years 2007, 2008, and 2009, related to its success in preventing the Federal Energy Regulatory Commission from approving several reliability must-run contracts. In November 2009, the DPU issued an order rejecting NSTAR's request, finding the approval of the request would not have resulted in "just and reasonable rates." As part of the decision, the DPU established a standard of review for CSI filings in which it indicated that in order to warrant recovery, the company must demonstrate that: (1) its proposal is an "eligible" initiative consistent with a multi-year rate agreement and order; (2) its performance with regard to its CSI proposal is "incremental" to the company's historical and expected level of activity; (3) the proposal is "attributable," i.e., its savings would not have occurred absent the company's actions; and, (4) the customer benefits in its proposal are "specific" and "measurable" and not subject to miscalculation or manipulation.

Western Massachusetts Electric Company's (WMECO's) operations were subject to a stipulated ESM that incorporated an 8%-12% ROE deadband for 2007 and 2008. The company was permitted to retain 50% of earnings above a 12% ROE and required to absorb 50% of any earnings shortfall below an 8% ROE. If earnings in 2007 or 2008 had dropped to a 7% ROE, WMECO would have been permitted to file a rate case, and if the company's ROE reached 13%, the AG would have been permitted to request that the DPU initiate a rate review.

Berkshire Gas is operating under an alternative regulation plan that was approved in 2002, and is to be in effect through Jan. 12, 2012. Following an initial rate increase, prices were frozen until September 2004, after which rates are to be adjusted annually based on the change in the GDP PI, less a 1% "consumer dividend." The plan contains no earnings restrictions.

As per a settlement adopted in 2007 for Fitchburg Gas & Electric's gas operations, earnings outside an 8-12% ROE are to be shared equally with ratepayers.

On Nov. 2, 2010, the DPU agreed to terminate Boston Gas' PBR that was approved in 2003. The PBR, which was to be in place for up to 10 years (through Oct. 31, 2013), included an ESM and price-cap provisions. Under the plan, beginning Nov. 1, 2004, prices were to be adjusted annually based on the change in the GDP-PI, less a 0.41% productivity offset ± exogenous costs that individually exceed $0.8 million. If earnings in a particular year were within a 6.2%-to-14.2% ROE range, there was no earnings sharing. If earnings were to fall below 6.2%, the earnings shortfall below 6.2% would have been shared 75%/25% by shareholders and ratepayers. If earnings were to exceed 14.2%, the incremental earnings above 14.2% would have been shared 75%/25% by shareholders and ratepayers.

From 2006 through Oct. 30, 2009, Columbia Gas of Massachusetts operated under a PBR that included an ESM and price-cap provisions. As initially approved, the plan was to be in place for up to 10 years through Oct. 31, 2016; however, on Oct. 30, 2009, as part of a general rate case, the DPU concluded that as a result of the rate request, the dynamics of the rate plan were altered. Under the PBR plan, prices were adjusted annually based on the change in the GDP-PI, less a 0.51% productivity offset, plus or minus exogenous costs that individually exceeded $0.6 million in the preceding calendar year. The ESM incorporated plus or minus 400-basis-points around the authorized ROE (initially 10%). If earnings fell below a 6% ROE or exceeded a 14% ROE, the amount outside of the range was to be allocated 75% to shareholders and 25% to ratepayers.

The local gas distribution companies may retain 25% of margins from interruptible gas sales that are above an annual target threshold. (Section updated 4/13/11)

Michigan Public Service Commission

Alternative Regulation

Detroit Edison (DE) is subject to a Choice Incentive Mechanism that incorporates a base level of customer choice (i.e., customer switching to a competitive electric supplier) sales, a deadband around the base level, and customer/stockholder sharing of non-fuel revenues associated with sales levels outside of the deadband range (see the Electric Regulatory Reform/Industry Restructuring section for additional details). A similar mechanism had been implemented for Consumers Energy (CE), but was terminated in November 2009.

Michigan Consolidated Gas (MCG) is subject to an uncollectibles expense true-up mechanism that was initially established in 2005 and subsequently modified on June 3, 2010. By March 31 of each year, MCG must tender a filing that compares the company's actual uncollectibles expense for the preceding calendar year with the base level of uncollectibles expense incorporated in the company's rates. Eighty percent of the difference is collected from, or refunded to, customers through a temporary surcharge or credit over the subsequent 12-month period. In November 2009, the PSC adopted a similar uncollectibles expense true-up mechanism for CE's electric operations, but the mechanism was terminated effective Nov. 30, 2010. Uncollectible expense true-up mechanisms are in place for DE, Upper Peninsula Power, and Michigan Gas Utilities. The company is authorized to recover from, or refund to customers, 80% of the difference between actual uncollectibles expense and those reflected in rates. A similar mechanism was terminated for Upper Peninsula Power effective Jan. 1, 2011. (Section updated 2/23/11)

Minnesota Public Utilities Commission

Alternative Regulation

Incentive demand-side-management (DSM) mechanisms are in place for regulated electric and gas utilities, including Northern States Power-Minnesota (NSP-M) and Minnesota Power. Specifically, the PUC sets KWH energy savings goals for each utility, and incentives begin when the utilities surpass 90% of these goals. The incentives are capped at the lower of 30% of actual expenditures or 30% of Office of Energy Security-approved expenditure levels.

State law permits the PUC to approve cost-recovery riders that include performance-based incentives for mercury emissions reductions in excess of 90% (see the Integrated Resource Planning section). To date, no incentive riders have been requested. (Section updated 4/13/11)

Mississippi Public Service Commission

Alternative Regulation

State statutes authorize the PSC to adopt alternative rate plans (ARPs). In 1986, the PSC adopted a Performance Evaluation Plan (PEP) for Mississippi Power (MP) that has been modified several times. The current PEP requires annual evaluations based upon data for the upcoming calendar year, with annual rate adjustments limited to 4% of retail revenues. Rate adjustments are based upon a company performance rating (CPR), with a price indicator allocated a 40% weighting, customer satisfaction 20%, and service reliability 40%. The price indicator is calculated based upon a comparison of MP's rates with those of vertically integrated companies that operate within the member states of the Southeastern Association of Regulatory Utility Commissioners. MP's benchmark return on equity (ROE) is calculated annually as of Oct. 1, based upon an equal weighting of the following methodologies--discounted cash flow, risk premium, and a capital asset pricing model--plus a 12.5-basis-point flotation cost premium.

MP's "Performance-Based Return on Investment" (PROI) is determined using the company's projected capital structure and a Performance-Adjusted Cost of Common Equity, which is the benchmark ROE, plus 10% of the CPR for that evaluation period. A "range-of-no-change" is established based upon the company's PROI, plus or minus 50 basis points. If MP's earned return on investment is within the range, no revenue adjustment is made for the evaluation period. If the earned return is outside the range, a revenue adjustment is made based upon a graduated formula that incorporates MP's CPR.

Entergy Mississippi (EM) has been operating under a formula rate plan (FRP) since 1994. The current version of the FRP requires the company to file a report with the PSC by March 15 of each year containing an evaluation of preceding calendar-year data, with any rate adjustments to be implemented following PSC approval. The company calculates: (1) its earned Rate of Return on Rate Base (ERORB), defined as net utility operating income divided by rate base; (2) the Performance-Adjusted Evaluation Period Cost Rate for Common Equity (PCOE)--the PCOE is derived by adding a Performance Rating Adjustment (PADJ) and a 12.5-basis-point flotation cost premium to the average of a discounted cash flow analysis and a regression analysis; (3) the PADJ may fall in a range of zero to 100 basis points, with price performance weighted 40%, customer satisfaction weighted 20%, and reliability weighted 40%; (4) a benchmark RORB (BRORB), essentially the company's cost of capital incorporating the PCOE; and, (5) a BRORB bandwidth, equivalent to the BRORB plus or minus 50 basis points. If the ERORB is within the BRORB bandwidth, no change in rates is made. If the ERORB is outside the BRORB bandwidth, rates are adjusted based upon a graduated formula that incorporates EM's PADJ. Annual rate adjustments under the FRP are capped at 4% of retail revenues. (Section updated 2/7/11)

Missouri Public Service Commission

Alternative Regulation

Empire District Electric, KCP&L Greater Missouri Operations, and Union Electric utilize fuel adjustment clauses that permit sharing, on a 95%/5% basis by ratepayers and shareholders, of incremental fuel-cost variations (see the Adjustment Clauses section). Missouri Gas Energy (MGE) has in place a framework that provides for sharing of a portion of off-system sales (OSS) and capacity release (CR) revenues, specifically: for the first $1.2 million of CR and OSS revenue, 15% would be allocated to the company and 85% to customers; for the next $1.2 million, 20% would be allocated to the company and 80% to customers; for the next $1.2 million, 25% would be allocated to the company and 75% to customers; and, above $3.6 million, 30% would be allocated to the company and 70% to customers.

From 1996 through 2001, Laclede Gas (LCG) operated under an alternative regulation plan that included sharing provisions for pipeline transportation discounts, CR revenues, and gas procurement. LCG is currently permitted to retain 10% of any gas-cost savings relative to an established benchmark. In addition, LCG shares with ratepayers, to varying degrees, OSS and CR revenues. Specifically: the first $2 million of OSS and CR margins are to be allocated 85% to ratepayers and 15% to shareholders; margins between $2 million and $4 million are to be shared 80%/20%; margins between $4 million and $6 million are to be shared 75%/25%; and, margins above $6 million are to be shared 70%/30%. A $3 million "sharing cap" also applies. (Section updated 9/15/10)

Montana Public Service Commission

Alternative Regulation

State statutes allow the PSC to approve up to a 200-basis-point return on equity (ROE) premium for demand-side management program investment. To date, no such premium has been requested. From 1996-1998, NorthWestern Corporation (then Montana Power) operated under an electric alternative regulation plan, that provided for earnings in excess of an 11.4% ROE to be shared equally with ratepayers.

On April 22, 2008, the PSC adopted a settlement that provides for MDU Resources to utilize a monthly-adjusted fuel and purchased power cost adjustment mechanism. Incremental changes in fuel and purchased power costs, and off-system sales margins are to be shared by ratepayers and shareholders on a 90%/10% basis through this mechanism, which is to terminate on Dec. 31, 2011, unless extended by the PSC. (Section updated 11/5/09)

Nebraska Public Service Commission

Alternative Regulation

Although there are currently no alternative regulation plans in effect for the state's natural gas utilities, the PSC has the authority to implement such plans. (Section updated 2/17/11)

New Hampshire Public Utilities Commission

Alternative Regulation

On June 28, 2010, the PUC adopted a settlement for Public Service Company of New Hampshire (PSNH) that established an earnings sharing mechanism under which 75% of earnings above a 10% ROE is to be shared with customers.

PSNH is permitted to retain 20% of any savings associated with the buyout of high-cost purchased power contracts with Public Utility Regulatory Policies Act qualifying facilities.

As part of a settlement adopted by the PUC in 2007, in connection with the National Grid and KeySpan Corporation merger, a rate plan is to be in effect for National Grid subsidiary Granite State Electric for the five-year period 2008 through 2012. The rate plan contains an earnings sharing mechanism (ESM), under which earnings above an 11% return on equity (ROE) are to be shared equally with customers. The ratepayer portion of shared earnings is to be returned to customers at the conclusion of the five-year plan. For former KeySpan subsidiary EnergyNorth Natural Gas, a sharing mechanism is to be in effect for at least ten years following merger closure (through August 2017), whereby the

company is to share equally any merger-related savings. An ESM is to go in effect beginning August 2017, under which the company would share equally with ratepayers any earnings over its authorized ROE (Section updated 8/26/10).

New Jersey Board of Public Utilities

Alternative Regulation

New Jersey Natural Gas (NJNG) is permitted to retain: 15% of the gross margin related to off-system gas sales and capacity release revenues; and, 20% of the benefit associated with reductions in gas storage costs relative to a pre-determined benchmark.

South Jersey Gas may retain 100% of the first $7.8 million of margins associated with off-system sales, interruptible sales, and interruptible transportation activities. Margins beyond this level are allocated such that 85% flows to ratepayers and 15% is retained by the company.

Pivotal Utility Holdings (PUH) shares equally with ratepayers the difference, up to $1 million annually, between a monthly market benchmark and the actual cost of gas. In addition, as per the BPU's 2004 order approving the acquisition of Elizabethtown Gas (now PUH) parent NUI Corp. by AGL Resources, PUH operated under a five-year rate freeze that expired at year-end 2009. In years one through three (2005-2007), there were no earnings restrictions; in years four and five (2008 and 2009), PUH was permitted to retain 25% of earnings in excess of an 11% ROE (see the Merger Activity section). (Section updated 2/9/11)

New Mexico Public Regulation Commission

Alternative Regulation

In a settlement adopted for Public Service Company of New Mexico in 2003, the parties agreed to allow the company to retain all revenues from off-system sales on a prospective basis. In 2004, the PRC approved a settlement for El Paso Electric that contains an “indirect” hedge – El Paso is permitted to charge a fixed price for fuel and purchased power expenses for 10% of its sales in New Mexico.

In a July 2007 rate decision that followed a settlement for El Paso, for the period July 1, 2007, through June 30, 2010, 25% of off-system sales margin is to flow back to customers through the fuel and purchased power cost adjustment clause (FPPCAC), with El Paso to retain the remainder; however, for the period July 1, 2010, through June 30, 2015, El

Paso is to flow through 90% of the margin through the FPPCAC. The parties noted that this treatment is consistent with the treatment of off-system sales margins in El Paso's Texas jurisdiction. Previously, there was no off-system sales cost sharing in New Mexico; El Paso retained all margin from such sales. (Section updated 2/20/08)

New York Public Service Commission

Alternative Regulation

The PSC has a long history of adopting multi-faceted, multi-year rate plans for the electric and gas companies. As indicated in the Return on Equity section, most of the major utilities are operating under regulatory plans that include earnings sharing provisions, with earnings in excess of an established ROE cap to be shared by stockholders and ratepayers. Certain of these plans include the potential for penalties related to service quality and customer service.

Several plans also include an incentive related to retail customer switching rates or the level of customers' understanding of retail choice. For example, Orange and Rockland Utilities' current gas rate plan provides for the sharing of earnings in excess of an 11% ROE; however, this threshold is reduced to 10.8% if during any rate year the company fails to earn the "Retail Choice Customer Understanding Incentive."

Consolidated Edison of New York (Con Ed) is currently operating under a gas rate settlement under which the company retains the first $35 million of net revenues from non-firm gas sales. Net revenues that exceed the threshold are to be retained by Con Ed in varying degrees. (Section updated 10/1/08)

North Carolina Utilities Commission

Alternative Regulation

Through April 2010, North Carolina Power operated under a five-year base rate freeze with no earnings restrictions, with the exception that rates could have been modified to reflect changes in federal or state taxes. (Section updated 12/8/10)

North Dakota Public Service Commission

Alternative Regulation

The Commission's performance-based-regulation (PBR) plan guidelines require such plans to: promote efficiency; align customer and shareholder interests; maintain and improve customer service; enable utilities to be flexible; minimize regulatory costs; and, improve public participation.

Northern States Power (NSP) and Otter Tail Power (OTP) operated under PBR plans from 2001 through 2005. Both plans included a 12% return-on-equity (ROE) benchmark, with a 200-basis-point dead-band (11%-13%), that was to be adjusted by as much as 175 basis points depending on the company's performance relative to PSC-approved benchmarks for: residential rate levels; system reliability; customer satisfaction; and, employee safety. Any earnings that exceeded the upper end of the ROE dead-band (after adjustments for performance) were required to be shared equally by shareholders and customers. If the companies were to earn an ROE below the low end of the ROE dead-band, one-half of the earnings shortfall was to be deferred and offset by any surplus experienced in the following year.

If the deferred shortfall from the prior year was not fully offset, any remaining shortfall was to be recovered through a surcharge. In addition, the companies were permitted to increase rates annually to account for inflation.

In December 2008, the PSC adopted a settlement providing for NSP to be subject to an earnings-sharing mechanism, such that the company is to equally share with ratepayers any earnings between a 10.75% and 11.25% ROE, and allocate earnings in excess of an 11.25% ROE on a 75%/25% basis to ratepayers and shareholders. The mechanism is to remain in place through 2011. The approved settlement also provides for prospective "asset based" wholesale power margins (WPMs) to be allocated on an 85%/15% basis to ratepayers and shareholders; "non-asset based" WPMs are to be allocated equally. The company is to flow the ratepayers' share of any WPMs through the fuel cost recovery mechanism.

NSP was subject to an earnings-sharing mechanism for its gas operations for a three-year term (calendar-years 2007, 2008, and 2009). Under the mechanism, the company equally shared with ratepayers earnings between a 10.75%-11.25% ROE. Any incremental earnings in excess of an 11.25% ROE were to be allocated 75%/25% to ratepayers and shareholders.

On Nov. 25, 2009, the PSC adopted a settlement that provides for OTP to operate under an earnings sharing mechanism, such that: earnings between a 10.75% and an 11.25% ROE are allocated equally between ratepayers and shareholders; and, earnings in excess of an 11.25% ROE are allocated on a 75%/25% basis to ratepayers and shareholders, respectively. The earnings sharing provision is to remain in place through 2011. In addition, the approved settlement provides for OTP to allocate prospective asset-based WPMs on an 85%/15% basis to ratepayers and shareholders, respectively.

MDU Resources is authorized to retain 15% of off-system sales margins in excess of those reflected in base rates. (Section updated 11/2/10)

Oklahoma Corporation Commission

Alternative Regulation

Oklahoma Gas & Electric (OG&E) is permitted to retain 20% of the margins associated with off-system sales, with the remaining 80% to flow to ratepayers through the fuel adjustment clause. The company may also retain 10% of the proceeds from the sale of SO2 emissions allowances.

CenterPoint Energy Resources is subject to a performance-based ratemaking (PBR) plan that was implemented in 2004, and is to remain in place through 2010. As modified in 2009, the PBR plan includes a 100 basis point deadband around a 10.5% return on equity (ROE), i.e., no rate changes are to be implemented if the company's actual ROE in a given year falls between 10% and 11%. If the earned return were to fall below 10%, CenterPoint would be permitted to increase rates to have an opportunity to achieve a 10.5% ROE prospectively. There is no "make-up" provision for years in which earnings fall short. All incremental earnings above an 11% ROE are to be allocated 75% to ratepayers and 25% to shareholders. In addition, the plan provides for the calculation of CenterPoint's actual earnings to reflect actual rather than weather-normalized revenues and the amount of bad debt expense included in the calculation to be capped at 3.5% of test year revenues.

In May 2009, the OCC authorized ONEOK to operate under a PBR plan that was to rely on parameters established in its next base rate case, which was ultimately resolved in December 2009. The PBR incorporates a 150-basis-point dead-band around a 10.5% ROE benchmark, such that if ONEOK's actual ROE exceeds the benchmark return by more than 75 basis points (an 11.25% ROE), the incremental return would be shared 75%/25% by ratepayers and shareholders. If ONEOK's actual ROE falls short of the benchmark return by more than 75 basis points (a 9.75% ROE), rates would be increased to allow ONEOK an opportunity to earn an ROE that is 25 basis points below the ROE benchmark (i.e., 10.25%) prospectively. There is no make-up provision for years in which earnings are below the deadband. ONEOK's initial PBR review filing is to reflect a calendar-2010 test period. ONEOK is required to tender a base rate case filing on or before June 30, 2014, and in that case the OCC is to consider the merits of continuing or modifying the PBR plan. (Section updated 9/27/10)

Oregon Public Utility Commission

Alternative Regulation
A proceeding is pending in which the PUC is investigating performance-based ratemaking mechanisms that may be used to address the potential build-versus-buy bias in electric utility resource procurement. Comments were filed by the parties in early 2008.

Northwest Natural Gas (NWN) is permitted to retain 33% of the margin associated with off-system gas sales and capacity release activity during periods of low demand.

The purchased gas adjustment (PGA) clauses for NWN, Cascade Natural Gas (CNG), and Avista Corporation contain sharing mechanisms with respect to changes in gas commodity costs. Each gas utility is to choose by Aug. 1 of each year an 80/20 or 90/10 customer/utility sharing ratio to be in effect for the winter heating season beginning Nov. 1. In connection with PGA sharing mechanisms, the PUC conducts annual earnings tests for each of the local gas distribution companies (LDCs) each spring. If earnings are above a specified benchmark return on equity (ROE) level, a portion of those revenues are to be credited to a deferred account and returned to ratepayers as part of the company's subsequent PGA filing. The earnings test is set at 150 basis points above the utility's authorized ROE for the 80/20 sharing and 100 basis point above the authorized ROE for the 90/10 sharing (see the Adjustment Clauses section). (Section updated 6/16/10)

Pennsylvania Public Utility Commission

Alternative Regulation
Columbia Gas of Pennsylvania (CGP) is authorized to retain a portion of the gross margin from off-system sales (OSS) and capacity release (CR). Under the mechanism, 75% of the net proceeds the company receives from OSS and CR activity flows to applicable customers and CGP retains the remaining 25%. Equitable Gas may retain a portion of the benefits associated with capacity release, off system sales, and hedging activities. Similar incentives have been approved for Peoples Natural Gas and PECO Energy's gas division. (Section updated 7/19/10)

Public Service Commission West Virginia

Alternative Regulation
No data available for the selected commission/section.

Public Service Commission of Wisconsin

Alternative Regulation

Electric fuel rules are in place that provide for utilities to retain/absorb a portion of savings/excess costs related to a variance around a PSC-established benchmark. Wisconsin Gas, Wisconsin Electric Power, and Madison Gas and Electric are currently operating under incentive gas cost recovery mechanisms. Depending on the specific details of a utility's incentive mechanism, a portion of gas costs may be subject to benchmarks from which excesses or deficiencies may be shared by both customers and stockholders (see the Adjustment Clauses section). As permitted by statute, the PSC may authorize equity returns that are applicable only to specific generation projects; see the Integrated Resource Planning section. (Section updated 4/27/11)

Public Service Commission of Utah

Alternative Regulation

Legislation enacted in 2009 codified the PSC's authority to approve incentive-based ratemaking mechanisms. Currently, there are no electric alternative regulation plans in place. Questar Gas is permitted to retain 10% of capacity release revenues (see the Adjustment Clauses section). (Section updated 10/20/10)

Public Utilities Commission of Ohio

Alternative Regulation

As a result of the enactment of electric industry restructuring legislation, effective Jan. 1, 2001, through year-end 2005, the electric utilities operated under hard rate caps; therefore, the investor-owned utilities were at risk for variations in fuel prices and purchased power costs. However, the utilities later operated under rate stabilization plans (RSPs) (see the Electric Regulatory Reform/Industry Restructuring section) that allowed for rate recognition of at least a portion of the increases in fuel prices, purchased power costs, and emissions expenditures. The utilities are now operating under Electric Security Plans (ESPs), that replaced the RSPs. The ESPs, with the exception of the ESPs for the operating companies of FirstEnergy, provide for recovery of fuel expenses through separate adjustment mechanisms. The price of power reflected in the FirstEnergy ESPs is determined through a competitive auction.

Gas utilities are permitted to use a gas cost recovery clause (GCR), which provides for quarterly adjustments, with an annual review and hearing. The GCR includes a mechanism to revise charges in a subsequent three-month period for any under- or over-recoveries related to the collection of an earlier period. With PUC approval, a local distribution company can make monthly changes to its GCR, and many companies are doing so. The PUC has established a framework for determining whether gas companies' procurement practices minimize overall costs to utility customers while assuring adequate supplies of gas.

In May 2006, the PUC approved a stipulation, thereby eliminating East Ohio Gas' (EOG's) GCR charge, and allowing the company to charge commodity prices that are determined through a descending-clock auction. The PUC indicated that the first phase of the plan will serve as a pilot program to test the ability of the new pricing methodology to enhance competition and reduce long-term natural gas rates. Typically, EOG obtained its gas through individually negotiated bilateral contracts. Under the new plan, EOG conducts an auction that allows suppliers to compete to supply portions of EOG's requirements. The company's customers have a choice of receiving natural gas directly from a competitive supplier or from EOG's retail sales service. EOG remains the provider of last resort during phase one. (Section updated 10/12/09)

Public Utilities Commission of Nevada

Alternative Regulation
The PUC's integrated resource planning rules permit the approval of incentive mechanisms for facilities designated as "critical." Under the rules, the PUC may designate a project as critical if it protects reliability, promotes supply diversity or develops renewable resources. For such a project, the utility may be awarded: (1) an enhanced return on equity (ROE) of up to 500 basis points on the designated critical facility over the life of the facility; (2) a cash return on construction work in progress (CWIP) associated with the facility; and/or, (3) the deferral of costs incurred to construct the facility. In addition, energy utilities are permitted to earn an incentive return (500 basis points above authorized ROE) on demand-side management investments.

In recent years, the PUC has designated several facilities as critical. In 2004, the PUC approved Nevada Power Company's (NPC's) purchase of a two-unit 1,200-MW natural-gas-fired combined-cycle plant (the Chuck Lenzie station) that was under construction, granted the station critical-facility status, and authorized an associated incentive equal to a 200 basis-point ROE premium on the construction portion of the Lenzie investment and an additional 100-basis-point ROE premium if the company could complete both combined-cycle units ahead of schedule. The company was ultimately permitted to earn a 300-basis-point ROE premium, as both units were completed ahead of schedule.

In 2005, the PUC approved Sierra Pacific Power's (SPP's) plan to construct a new 514-MW combined-cycle natural gas unit at the Tracy station. In approving the construction of the unit, the PUC granted the plant critical-facility status, and authorized the company a 150-basis-point ROE premium on the facility's construction costs. The plant began commercial operation in July 2008. In 2006, the PUC approved the development of the Ely Energy Center and established the project as a critical facility. The PUC ruled that specific incentives would be determined at a later date. NPC has since abandoned plans to construct the facility.

On July 30, 2010, the PUC granted critical facility status to NPC for its $121 million projected investment in the 500-KV, 235-mile On Line transmission facility, which is being jointly developed by NV Energy and LS Power. The PUC has allowed NPC to defer the incremental ON Line project operation and maintenance costs. SPP was not granted critical facility treatment for its portion of the investment in the ON Line facility, as the PUC found that the company's projected capital cost ($5.6 million) was not material and, therefore, would not impact its credit metrics.

From 1997 through 1999, an earnings sharing mechanism was in place for SPP's electric and gas divisions under which earnings in excess of a 12% ROE during each calendar year were to be shared equally by shareholders and ratepayers. Despite legislation enacted in 1997 that expanded the PUC's ability to implement broad-based alternative regulation plans for gas utilities, no such plans are currently in place. (Section updated 4/25/11)

Public Utility Commission of Texas

Alternative Regulation
El Paso Electric (EPE) is operating under an agreement reached in 2005 with the City of El Paso. Under the agreement, base rates were frozen through June 2010. EPE is subject to an earnings sharing plan, under which no rate change is to occur if the company's earned return on equity (ROE) is within 200 basis points of a benchmark ROE equal to "the published average utility bond yield," plus 400 basis points. If earnings are above the upper end of the deadband, the company would refund 50% of the excess; if earnings are below the lower end of the dead band, the company would be permitted to file a rate case. In addition, the agreement provides for wheeling and off-system sales revenues to be allocated 75% to ratepayers and 25% to shareholders. (Section updated 1/20/11)

Railroad Commission of Texas

Alternative Regulation
No data available for the selected commission/section.

Rhode Island Public Utilities Commission

Alternative Regulation
From 2004 through Dec. 31, 2009, Narragansett Electric (NE) operated under a rate plan, whereby electric distribution rates were largely frozen, but were subject to adjustments for certain exogenous factors. Earnings between a 10.5% and 11.5% ROE were to be shared equally with ratepayers, and earnings above an 11.5% ROE were to be allocated 75% to ratepayers and 25% to shareholders. A service quality plan was in effect during the rate-freeze period, with annual financial penalties of as much as $2.2 million to be applied if the standards are not met. Discussions are underway as to whether earnings sharing is to continue beyond Dec. 31, 2009.

As part of a rate case decision issued in November 2008, the PUC adopted an earnings sharing mechanism (ESM) for NE's gas operations. Under the ESM, NE is to share equally with ratepayers all earnings between a 10.5% and 11.5% ROE. Incremental earnings above an 11.5% ROE are to be shared 75%/25% by ratepayers and shareholders (Final Report 2/10/09). NE retains 25% of all non-firm gas margins earned in excess of $1.6 million, and was permitted to retain $2 million of annual net merger related savings until July 1, 2010.

Legislation enacted in 2009 requires electric distribution companies to enter into long-term contracts with renewable energy facilities and also provides for electric distribution utilities to receive an incentive payment equal to 2.75% of the annual contract payments from the renewable energy contract (see the Renewable Energy section). (Section updated 10/25/10)

Public Service Comm. of South Carolina

Alternative Regulation
State law permits natural gas utilities, upon PSC approval, to adjust rates once per year if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. Any rate adjustment would be based on the last authorized ROE. The gas utilities must request any rate change by June 15 of each year in conjunction with their March 31 quarterly surveillance filings, and a written PSC order must be issued by October 15. (Section updated 7/27/10)

South Dakota Public Utilities Commission

Alternative Regulation

Black Hills Power (BHP), through its fuel and purchased power adjustment clause (FPPAC), credits ratepayers 90% (and retains 10%) of the margins from renewable energy credit sales, and 65% of power marketing income (PMI) (retaining 35%), which is defined as the revenue from wholesale power and emission allowances sales, less certain expenses related to the operation of the wholesale business. The minimum annual PMI credit allocated to ratepayers via the FPPAC is $2 million. In addition, BHP is to credit ratepayers, via the FPPAC, surplus energy credits related to wholesale power sales at the Wygen III facility ($2.5 million, $2.25 million, and $2 million in 2011, 2012, and 2013).

In January 2010, the PUC approved a settlement that provides for Northern States Power (NSP) to operate under certain wholesale power margin (WPM) sharing provisions, whereby: non-asset-based WPMs are allocated on a 75%/25% basis to shareholders and ratepayers, respectively; and, 100% of asset-based WPMs are allocated to ratepayers. The company is to flow the ratepayers' share of any such margins through its fuel clause (see the Adjustment Clauses section).

MidAmerican Energy (ME) operates under a gas-procurement incentive plan that is based on a benchmark reference price, established semi-annually, that reflects gas commodity cost indices, storage and transportation tariffs approved by the Federal Energy Regulatory Commission, and capacity contracts entered into by the company. The plan contains a sharing mechanism that allocates savings and costs relative to the reference price between ratepayers and the company. For actual costs between 98.5% and 95% of the benchmark reference price, ME may retain 25% of the savings within the band. For costs between 95% and 91.5% of the reference price, ME may retain 50% of such savings. Below 91.5%, all savings flow to customers. For costs between 101.5% and 104% of the reference price, ME is to absorb 40% of the excess costs within the band. All costs above 104% of the Reference Price are to be passed through to customers. (Section updated 3/25/11)

Tennessee Regulatory Authority

Alternative Regulation

Piedmont Natural Gas (PNG) operates under an incentive plan that applies to capacity-management and off-system sales (OSS). Regarding OSS, the net benefits of such activities that vary from a predetermined benchmark are allocated 75% to ratepayers and 25% to shareholders. Separately, cost savings or fees associated with capacity management are shared 75%/25% between ratepayers and shareholders, respectively. Overall incentive gains or losses of the plan are capped at $1.6 million annually. The plan is reviewed every three years by an independent consultant.

Atmos Energy operates under an incentive plan that contains gas procurement and capacity-release incentives. Under the gas procurement incentive mechanism, Atmos is permitted to retain 50% of savings associated with gas costs that are less than 97.7% of a predetermined benchmark (lower band), and is required to absorb 50% of gas costs that are more than 102% of the benchmark (upper band). Under the capacity management incentive mechanism, Atmos may retain 10% of capacity-release revenues. The company is subject to a $1.25 million annual cap on overall incentive gains or losses. As part of the plan, Atmos must abide by affiliate relationship guidelines established by the TRA.

Chattanooga Gas (CG) operates under a performance-based-ratemaking mechanism that exempts the company from TRA prudence audits of its gas procurement activities if CG's gas commodity costs during a given evaluation period do not exceed a TRA-approved benchmark by more than 1%. Under its interruptible margin credit rider, CG equally shares with ratepayers margins resulting from transactions with non-regulated customers that utilize CG assets. (Section updated 3/11/11)

Vermont Public Service Board

Alternative Regulation

Under state law, the PSB is permitted to adopt alternative regulation plans (ARPs) for energy utilities if it determines that the plan will: (1) establish clear incentives to provide least cost service; (2) provide just-and-reasonable rates; (3) deliver safe and reliable service; (4) offer incentives for innovations and improved performance that advance state energy policy, such as increased reliance on Vermont-based renewable energy; (5) promote improved quality of service, reliability, and service choices; (6) establish a reasonably balanced system of risks and rewards; and, (7) provide a reasonable opportunity, under sound and economical management, to earn a fair rate of return. The PSB may also adopt power cost adjustments (PCAs) and purchased gas adjustments (PGAs) as part of an ARP.

Green Mountain Power (GMP) is operating under a multi-year ARP. On April 16, 2010, the ARP, which was initially approved in 2006, was extended by the PSB with modifications through Sept. 30, 2013. Under the ARP, the allowed return on equity (ROE) is adjusted annually to reflect one-half of the change in the yield in the 10-year Treasury note, as measured over the 20-trading-day-period ending two weeks prior to the Aug. 1 rate filing (see below). In accordance with the prescribed methodology for calculating the ROE under the ARP, the authorized ROEs for 2008, 2009, 2010 and 2011 were 10.21%, 9.81%, 9.69%, and 9.45%, respectively. However, beginning Oct. 1, 2011, the ROE is to be subject to a performance adjustment of up to plus or minus 50 basis points depending upon GMP's operating efficiency. This adjustment is to be based on the same cost-per-customer formula and benchmark utility group that is to be used for the non-power cost cap. The ARP contains an earnings sharing mechanism (ESM) that provides for a 150-basis-point deadband around the authorized ROE. Incremental earnings above the upper end of the range are to be returned to customers, with GMP to recover 50% of any earnings shortfalls between 75 and 125 basis points below the authorized ROE, and all earnings shortfalls in excess of 125 basis points below the authorized ROE. The ARP permitted rate changes in January 2008, January 2009, October 2009, and October 2010, as supported by cost-of-service information filed by November 1 of the proceeding year (by August 1 with respect to the October 2009 and 2010 rate change). GMP would be permitted to implement subsequent rate increases effective Oct. 1, 2011, and 2012, if such increases were supported by cost-of-service information filed by Aug. 1 of each year. For the years 2008 through 2009, base rate changes, excluding exogenous cost changes and any rate impact associated with a change to the authorized (ROE), were subject to predetermined limits of $1.25 million in 2008, $1.1 million in January 2009, and $1.6 million in October 2009. However, non-power-cost rate changes for October of 2010, 2011 and 2012, are to be subject to a cap based on the costs embedded in the rates determined for the previous year. The cap is to be adjusted for inflation as measured by the Consumer Price Index-New England, less a productivity factor of 1%, plus adjustments for capital spending, exogenous changes (exceeding $0.6 million), and any incremental ROE adjustment. In addition, effective with the rate changes beginning in October 2010, the modified ARP calls for an upward "incentive adjustment," which is to offset the 1% productivity factor and is to reflect GMP's operating efficiency relative to a benchmark group of utilities. A PCA was adopted as part of the ARP (see the Adjustment Clauses section).

In 2008, the PSB adopted a modified ARP for Central Vermont Public Service (CVPS) that is to be in place from Nov. 1, 2008 through Dec. 31, 2011. Under the ARP, the allowed ROE (initially set at 10.21%) is to be adjusted annually to reflect one-half of the change in the yield in the 10-year Treasury note, as measured over the last 20 trading days to Oct. 15 of each year. For calendar-2009 and 2010, the authorized ROE was 9.77% and 9.59%, respectively, and in accordance with the prescribed methodology, the ROE for 2011 is 9.18%. The ARP also includes provisions for: a PCA (see the Adjustment Clauses section), under which rates are to be adjusted quarterly for differences between projected and actual power costs; annual base rate adjustments reflecting changes in non-power-related costs; and, an ESM commencing Jan. 1, 2009, that provides for a 150-basis-point deadband around the authorized ROE. CVPS will be permitted to recover 50% of any earnings shortfalls between 75 and 125 basis points below the authorized ROE, and recover all earnings shortfalls in excess of 125 basis points below the authorized ROE. Earnings in excess of 75 basis points above the allowed ROE are returned to consumers. Non-power-cost rate changes are to be implemented each Jan. 1, and beginning in 2010 are to be subject to a cap that is to be calculated based on the costs embedded in the base rates determined for the previous year adjusted for inflation, less a productivity offset of 1%. We note that CVPS has filed to amend and extend the ARP through Dec. 31, 2013.

Vermont Gas Systems, Inc. (VGS) is operating under an ARP that commenced Oct. 1, 2006, and was initially scheduled to expire on Sept. 30, 2009. The ARP may be extended for two successive two-year terms, but may not continue beyond Sept. 30, 2013. In September 2009, the PSB approved the company's proposed two-year extension to Sept. 30, 2011, and adopted a settlement reached by VGS and the Department of Public Service conditioning the extension upon a reduction in the company's return on equity to 10.25% (from 10.5%) effective Jan. 1, 2010. Under the ARP, base rates may change each January, with such rate changes to be subject to a revenue cap, equal to a certain dollar amount per customer, adjusted by inflation, less a productivity offset. Prior to implementation, the rate change is to be adjusted by 50% of the difference between the revenue change as calculated by the cap and that provided under cost-of-service-regulation.

VGS' ARP also contains an ESM, which includes a 100-basis-point deadband around the authorized ROE within which rates would not change (the deadband is currently 9.75%-10.75%). Under the ESM, VGS is to recover from customers 50% of the earnings that fall short of the lower end of the deadband up to 200 basis points below the authorized ROE, and retain 25% of earnings that exceed the upper end of the ESM deadband up to 200 basis points above the authorized ROE. Earnings that are greater than 200 basis points above the authorized ROE are to be returned to ratepayers. The full amount of earnings by which the company falls short of earning more than 200 basis points below the authorized ROE is to be recovered from ratepayers. Rate adjustments associated with the ESM are to occur as part of the annual base rate change each January. As part of the ARP, the PSB also adopted a PGA (see the Adjustment Clauses section). (Section updated 1/25/11)

Virginia State Corporation Commission

Alternative Regulation

From 1997-2002 Virginia Electric Power (VEPCO) was subject to an earnings sharing mechanism that allowed the company to retain earnings up to a 10.5% ROE, with two-thirds of incremental earnings up to 270 basis points above the benchmark and all incremental earnings in excess of 270 basis points above the benchmark to be used to accelerate recovery of regulatory assets. From 1999-2002, Appalachian Power (APCO) operated under a similar plan that allowed the company to retain one-third of earnings in excess of a 10.85% ROE.

Legislation enacted in 2007 grants the SCC authority to approve comprehensive performance-based ratemaking plans for electric utilities. The legislation also allows a utility to retain 40% of incremental earnings in excess of the company's authorized return and states that the SCC may approve up to a 100-basis-point ROE premium or penalty for operating performance.

In addition, the SCC may approve incentive returns for certain types of new generation. Specifically, the statute provides that the SCC may approve up to a: 200 basis-point ROE premium on new nuclear generation facilities through the first 12 to 25 years of the plant's operation; 200-basis-point ROE premium on new carbon-capture compatible, clean-coal-powered facilities through the first 10 to 20 years of commercial operation; 200-basis-point ROE premium on new renewable resources through the first 5 to 15 years of commercial operation; and, 100-basis-point ROE premium on new conventional coal or combined-cycle combustion turbine plants through the first 10 to 20 years of commercial operation. The SCC has approved a 100-basis-point ROE premium to be applied to Virginia Electric & Power's investment in the Virginia City Hybrid Energy Center through the first 12 years of the plant's useful life and the Bear Garden Generation facility for the first 10 years of the plant's useful life.

The 2007 legislation also provides incentives for the utilities to participate in voluntary renewable portfolio standards programs. Specifically, a utility would be entitled to a 50-basis-point overall ROE premium if certain renewables targets are achieved (see the Renewable Energy section).

Margins on electric off-system sales are allocated 75% to ratepayers and 25% to shareholders, with such sharing accomplished through the fuel adjustment clause.

In 2006, the SCC adopted a settlement outlining an ARP under which Virginia Natural Gas' (VNG's) base rates are to be frozen through July 31, 2011, with no earnings restrictions (Final Report 8/21/06). Under a separate plan, VNG shares equally with ratepayers any gas costs that deviate from Commission-approved benchmarks.

Also in 2006, the SCC adopted a settlement for Columbia Gas of Virginia (CGV) under which base rates are to be frozen at current levels through Dec. 31, 2010. CGV's authorized ROE range for the purpose of earnings monitoring was 9.5% to 10.5%, and 75% of any incremental earnings above a 10.5% ROE were to flow to ratepayers. The plan was not continued as part of CGV's most recent (2010) rate case decision (see the Final Report dated 1/14/11).

In 2007, the SCC adopted an ARP for Washington Gas under which base rates will be frozen through Sept. 30, 2011, with earnings above a 10.5% ROE to be allocated 25% to shareholders and 75% to ratepayers (FN 9/21/07). (Section updated 3/30/11)

Washington Utilities and Transport Comm

Alternative Regulation

Incentive power cost adjustment mechanisms (PCAMs) are in effect for Avista Corporation and Puget Sound Energy (PSE). The PCAMs permit the utilities to absorb or retain a portion of energy cost differences from a baseline amount that is reflected in bases rates (see the Adjustment Clauses section).

State statutes permit the WUTC to grant financial incentives, e.g., a 200-basis-point adder to the company's authorized ROE for a period of at least seven years, but not more than 30 years, specifically on investments in distributed generation and certain energy efficiency measures.

A pilot electric conservation incentive mechanism (ECIM) was in effect for PSE from January 2007 through Dec. 31, 2009, under which the company was subject to incentives/penalties based on achievement of energy savings relative to a preset target.

State law permits the WUTC to consider whether incentives should be provided to electric investor-owned utilities for exceeding their conservation targets. On Nov. 4, 2010, the WUTC issued a policy statement regarding decoupling (see the Adjustment Clauses section) and conservation incentives, in which it indicated that it would consider conservation incentives for both electric and gas utilities. For electric utilities and combination electric and gas utilities, such incentives may be proposed with the companies' biennial electric conservation filings (see the Integrated Resource Planning section). For gas utilities, conservation incentives may be proposed as part of a general rate case.

From 1998 through October 2001, an incentive purchased gas adjustment mechanism was in effect, under which PSE was permitted to retain a portion of the benefit associated with competitive gas purchasing and pipeline and storage capacity management activities. From 1999 through Jan. 24, 2004, a natural gas benchmark mechanism was in place for Avista. Under the mechanism, Avista was permitted to retain a portion of the benefit associated with an agreement to purchase gas from its affiliate Avista Energy. (Section updated 1/20/11)

Wyoming Public Service Commission

Alternative Regulation

By law, the Commission may approve rates that contain incentive provisions related to efficiency, improved performance, modernization, and cost control for the state's electric and gas utilities.

Cheyenne Light, Fuel & Power (CLF&P) utilizes a power cost adjustment mechanism (PCAM) that permits sharing, between ratepayers and shareholders on a 95%/5% basis, of fuel and purchased power costs that are outside a $2 million dead-band around a base level of such costs.

PacifiCorp currently operates under a PCAM that contains sharing provisions and extends to March 31, 2012. The PCAM incorporates a symmetrical graduated sharing of actual power costs that vary from a baseline level according to the following formula: PacifiCorp is required to absorb incremental total annual net power costs (NPC) that vary by up to $40 million from the baseline level; incremental NPC variations of between $40 million and $100 million from the baseline level are shared 70%/30% by ratepayers and shareholders; incremental NPC variations of between $100 million and $200 million from the baseline level are shared 85%/15% by ratepayers and shareholders; and, incremental NPC variations greater than $200 million from the baseline level are shared 90%/10% by ratepayers and shareholders.

On Feb. 4, 2011, the PSC authorized PacifiCorp to operate under an "energy cost adjustment mechanism" (ECAM) following the expiration of the PCAM, for a five-year period beginning on April 1, 2012. Under the ECAM, incremental variations in NPC that differ from the base level are to be shared on a 70%/30% basis between ratepayers and shareholders, respectively.

Gas utilities may retain up to 10% of gas-procurement cost savings relative to the level reflected in their purchased gas adjustment clauses (for more information on the aforementioned adjustment clauses, refer to the Adjustment Clauses section). (Section updated 4/29/11)