State Policies for Utility Investment in Energy Efficiency

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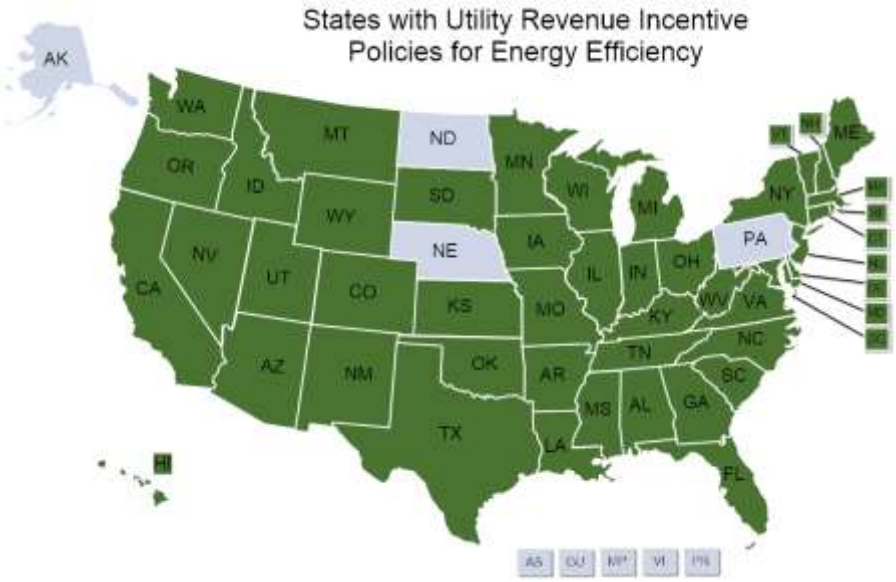
Introduction

Energy efficiency delivers several benefits including, reducing pollution, saving households and businesses money on energy bills, improving health and comfort, increasing electric grid resilience, creating jobs and expanding economic development. Additionally, by investing in efficiency, utilities can defer or avoid building new power plants. Being the cheapest energy resource, efficiency is also an excellent investment, with research finding that it often returns benefits of $2 or more for each dollar invested.

However, energy efficiency faces market and other barriers, some of the largest of which are regulatory and legal barriers. Under many utility business models, greater profits are linked to selling more energy and making more capital investments—objectives that conflict with energy efficiency, which seeks to reduce energy usage and waste. There are policies and strategies that states have employed to address these barriers, including utility regulatory reforms. Certain policies and changes to utility business models can incentivize utilities to invest in energy efficiency instead of investing in electricity generation resources. This webpage explores state policy options to promote cost-effective utility investments in energy efficiency, including decoupling mechanisms, lost revenue adjustment mechanisms (LRAMs) and performance incentives.

Overview

Energy efficiency is an appealing option for state policymakers looking to lower energy costs, reduce air pollution and promote local economic growth. Utilities also recognize the benefits that energy efficiency can provide for ratepayers—such as lower utility bills, increased system reliability, reduced greenhouse gas emissions and increased customer satisfaction. When implemented on a large scale, energy efficiency measures may take the place of new power plants and transmission and distribution projects, reducing utility expenditures and risk while lowering costs.



Studies have shown that without the proper ratemaking policies, regulations and incentives, utilities often fail to take advantage of many opportunities for efficiency. This is due to the outdated regulatory structures in many states, which generally reward investor-owned utilities for selling more electricity or natural gas and for building infrastructure.

Traditional Utility Regulation

Investor-owned utilities have traditionally been compensated based on their *revenue requirement*. A revenue requirement is determined by calculating a utility's expected reasonable operating expenses and adding a fair rate of return. Once a revenue requirement is set, regulators use sales data to calculate the rate needed to recover an amount equal to the revenue requirement. In theory, this creates a system where a utility's revenue requirement directly parallels its cost of service.

Once a rate has been set, it is fixed until the next rate case, leaving the utility's revenue heavily dependent on its electricity sales—the more energy a utility sells, the more money it earns. This dynamic, often called the "throughput incentive," puts a utility's goals in conflict with the desires of its ratepayers. While customers seek to reduce their energy bills to save money, the utility is motivated to sell more electricity and generate higher customer bills.

The compensation that utilities receive for capital investments, such as building power plants and power lines, also discourages efficiency efforts under the traditional regulatory model. Public utility commissions authorize utilities to recoup their expenses for building and operating power generation and transmission and distribution infrastructure, with added profit, through charges on customers' bills. This incentivizes utilities to invest in power

plants, transmission lines and other infrastructure. Although energy efficiency can be a substitute for new power plants and power lines, it can lower utility earnings under traditional utility business models. Despite the potential for efficiency investments to reduce costs for all customers and the utility, in most states, utilities are not provided with a return for these investments. Ultimately, traditionally regulated utilities receive a lower return on efficiency investments than they do for capital investments in power plants and power lines.

The current energy landscape is rapidly changing with increased demand for clean energy, growing amounts of customer-sited energy generation and new distributed energy resource technologies. While efficiency is seen as a resource that lowers energy demand and increases productivity, the traditional utility business model creates substantial financial disincentives for utilities looking to develop these programs. As a result, many states are exploring and establishing policies that motivate cost-effective efficiency investments.

Overcoming Disincentives

At least 44 states and Washington, D.C. have established utility revenue incentives for energy efficiency through decoupling mechanisms, lost-revenue adjustment mechanisms (LRAMs) and performance incentives. The next three tabs explore these approaches in detail and include state policy maps and summary tables.

Decoupling

Without a policy that addresses efficiency's potential to reduce sales and revenue, utilities that aggressively pursue efficiency may struggle to recover their fixed costs, such as investments, labor and investor earnings. Decoupling is one regulatory mechanism that states have implemented to address this concern. States can enable decoupling through legislation or through the public utilities commission. Of the 31 states that have authorized decoupling, at least 11 states—Connecticut, Illinois, Maine, Michigan, Minnesota, Nevada, Ohio, Rhode Island, Vermont, Virginia and Washington—and Washington, D.C. enacted legislation to enable decoupling, while the remaining states enabled decoupling through the public utilities commission orders and utility rate cases.

Decoupling breaks the link between electricity sales and profits while allowing utilities to collect approximately the same revenue as they would under traditional regulation. Unlike traditional regulation, in which energy prices are fixed and revenues fluctuate along with electricity sales, decoupling mechanisms allow rates to be adjusted up or down as a utility's actual energy sales fluctuate above or below the amount needed to cover their revenue

requirement. Decoupling rate adjustments are set to reflect the difference between predicted and actual sales, allowing for full revenue recovery. These rate adjustments are typically small, between 0 and 3 percent, and can take place as frequently as each billing cycle. This produces a predictable revenue stream for utilities that allows for full recovery of investments and operating costs, even if sales decline due to efficiency improvements.

View the chart below for a full listing of state decoupling policies.

Decoupling Policy Variations

When designing decoupling policies, lawmakers and regulators have a number of policy details to consider. For instance, whether decoupling should be mandatory for all investor-owned utilities, such as in California, or whether it is optional. According to the Regulatory Assistance Project (RAP) decoupling policy variations fall into three broad categories: the applicability of the decoupling policy; variations in the structure of revenue adjustments; and addressing revenue surplus or deficits.

Policy Applicability

Regulators decide what utility functions, costs and utility types that decoupling policies apply to. Decoupling can be applied to all utility functions, including generation, transmission and distribution. In restructured states—where utilities may not be able to own electricity generation—decoupling generally applies to distribution and in many cases transmission. In vertically integrated states, where utilities are allowed to own generation,

decoupling may apply to distribution, transmission or generation only, or it may apply to all three.

The type of utilities that decoupling will apply to—whether investor-owned, municipal, cooperatives, or all three—is determined by policymakers.

Other decisions for regulators are which costs to include in a revenue decoupling mechanism and what portion of their revenue shortfall utilities can recover. States have implemented *full*, *partial* or *limited* decoupling. Under *full decoupling*, utilities can recover the entire difference between allowed and actual revenue, whether it was caused by efficiency measures, weather fluctuations or any other established reason. For example, in 2012 the Arizona Corporation Commission approved a full decoupling mechanism for one of the state's natural gas utilities. The mechanism includes a weather adjustment clause and allows the utility to recover the entire difference between actual and authorized revenue independent of the cause of the difference. In contrast, under *partial decoupling*, utilities are only allowed to recover part of their revenue shortfall. An example of this was the combination energy savings-based incentive and decoupling mechanism that Avista Utilities previously had in place. Avista was allowed to recover a percentage of its lost revenue from sales declines in proportion to its percentage achievement of its conservation target, approved by the Washington Utilities and Transportation Commission. If Avista achieved its full conservation target, it could recover all of its lost margins. However, if it achieved only a portion of the target, the utility was only allowed to partially recover its lost revenue. Avista replaced this mechanism with a full decoupling mechanism in 2014. Under *limited decoupling*, only variations in sales due to certain factors are eligible for recovery. For example, only reductions in sales caused by weather can be recovered, while reductions due to increased efficiency cannot.

Finally, states also face the choice of approving decoupling for electric utilities, natural gas utilities or both. Michigan enacted Senate Bill 437 in 2016, which authorized the Public Service Commission to approve revenue decoupling for both electric and gas sales. However, other states and jurisdictions, such as Washington, D.C., have implemented revenue decoupling for electric utilities only.

Structure of Revenue Adjustments

Policymakers must also decide whether a utility's allowed revenue can be adjusted over time or whether allowed revenue is determined in rate cases. As decoupling allows for price fluctuation and keeps revenue relatively stable, it may result in less frequent rate cases. This presents challenges when new customers, inflation and general increases in operating costs

create discrepancies between the allowed revenue established in a previous rate case and a utility's change in underlying fixed costs. States have addressed this challenge by adopting a variety of procedures that allow for revenue adjustments between rate cases. Among the most used are adjustments for inflation and productivity, adjustments on a per-customer basis and adjustments based on a specified percentage reflecting a fixed increase in revenue. States have also taken hybrid approaches that incorporate several adjustment types.

California's decoupling policy offers an example of an attrition adjustment that changes the utility's allowed revenue based on a list of factors during an annual review. Utah represents a revenue per-customer approach. Utah approved a "conservation enabling tariff (CET)," which is based on the number of customers that the utility serves instead of the customers' gas usage. Under the CET, the utilities' allowed revenue fluctuates with the number of customers it serves.

Addressing Revenue Surplus or Deficits

Although decoupling is designed to assure that actual and authorized revenues are equal, actual revenues are typically over or under authorized revenues. These deviations are addressed through decoupling adjustments. Decoupling adjustments are not a new cost or new saving, but rather rate adjustments, either upward or downward, to allow utilities to reach a target revenue. Regulators can determine how these adjustments are made, how often they take place, the size of decoupling adjustments and how over- and under-recoveries are allocated to customers.

Decoupling adjustments can be included in rate cases or they can be included in a customer's total rate. Adjustments typically occur monthly, quarterly and annually, and each option has its own considerations. While monthly adjustments are generally more accurate in aligning actual and authorized revenues, yearly adjustments may smooth out shorter-term volatility and result in smaller adjustments overall.

Although decoupling adjustments typically range from 1 to 3 percent, they can vary in size. To manage customer expectations and impacts, regulators can establish a cap on adjustments. These limits can be a percent or dollar amount cap on rate changes or revenue increases.

State-by-State Decoupling Policies

Decoupling policies have been adopted by at least 32 states and Washington, D.C. for electric or natural gas utilities or both. Three states and Washington, D.C. have electric-only decoupling, 12 states have gas-only, and there are at least 17 states with decoupling for both.

State	Type	Year	Authority	Current Model Summary
Alabama	Both	2007	Dockets 18117 and 18416	Alabama Power Company and Alabama Gas Company recover their costs through the Rate Stabilization and Equalization (Rate RSE). Revenue adjustments can be made based on whether the calculated return rate falls above or below the authorized range.
Arizona	Gas	2012	Docket Number G-01551A-10-0458, Decision #72723	The decoupling mechanism applies throughout the year on a per-customer basis. The mechanism includes a limit on collection up to the authorized return on equity and has a 5 percent cap adjustment for a given year. The mechanism includes a weather adjustment clause for the months of November through April.
Arkansas	Gas	BDA tariff: 2007-2010; decoupling 2013.	Docket No. 07-016-U; Order No. 15 Docket 08-137-U.	In rate cases, the Arkansas PSC approved a decoupling mechanism, a billing determinant adjustment (BDA) tariff, to promote efficiency for the three major natural gas distribution companies in the state. The BDA tariff accounts for reductions in non-gas revenues due to declining gas volumes caused by conservation and decreasing billing determinants. In 2013, the PSC issued an order inviting utilities to file decoupling proposals in their rate cases. The order included design suggestions but left the design to the utilities' discretion.
California	Both	Initially implemented in 1978; current mechanism implemented in 2004.	Cases A.02-11-017 and A.02-12-027.	California requires the public utilities commission to implement decoupling and all three investor-owned utilities—Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric—have developed and applied decoupling mechanisms. The revenue decoupling program is combined with performance incentives for meeting or exceeding energy efficiency targets.
Colorado	Electric	2017	Proceeding No. 16A-0546E	Colorado has a Revenue Decoupling Adjustment that adjusts future electricity base rate revenues from June 1, 2018 through May 31, 2023. There is a 3 percent cap on how much a utility can recover in a year.

Connecticut	Both	2014 electric; 2009 gas.	Docket No. 13-01-19; Docket No. 08-07-04RE03; House Bill 7432 (2007); House Bill 6360 (2013).	The mechanism reconciles actual non-weather adjusted revenues to ratemaking revenues. Refunds or charges are allocated to every class based on revenue. The mechanism does not allow adjustments if revenue difference is less than $1 million.
Delaware	Both	*Pending*	Order 7641, Docket Number 09-276T.	Decoupling is evaluated on a utility-by-utility basis when setting utility rates. The docket has been on hold since 2011 and the decoupling mechanism has not yet been implemented.
District of Columbia	Electric	2009	Clean and Affordable Energy Act of 2008; Case 1053-E-361.	The mechanism calculates adjustments monthly by comparing actual revenue per customer to test year revenue per customer within each service class.
Georgia	Gas	2012	Docket No. 34734.	This mechanism compares actual non-gas revenue to authorized non-gas revenue and mandates refunds or surcharges based on the difference. Authorized revenues are updated annually to test year and adjustments are made to bring return on equity up or down to specified percentages.
Hawaii	Electric	2010	Docket No. 2008-0083.	Compares actual adjusted revenue to a target revenue, which is calculated based on the test year. Includes adjustments for escalation in operation and management, and rate base changes.
Idaho	Both	2007, 2017	Case No. IPC-E-11-19, Order No. 32505; Case No. AVU-G-17-03, Order No. 33919.	The mechanism is a based on authorized per-customer revenue, adjusted for weather, determined by fixed costs from previous rate cases. Adjustments are capped at three percent over the previous year but are allowed to carry over to subsequent years.
Illinois	Both	2008	Gas: Docket No. 07-0242; Docket No. 07-0241. Electric AMI: Ill. Rev. Stat. ch. 220, §5/16-108.5.	For gas utilities, the mechanism compares actual, non-weather adjusted margin of revenue per customer to the authorized per-customer revenue on a class basis. Monthly adjustments are allowed, but utilities must also make annual fillings. Electric utilities do not have an explicit decoupling rider for energy efficiency. However, as part of the advanced

				metering infrastructure installation process, utilities use formula rates that adjust every year based on actual costs and actual sales in previous years.
Indiana	Gas	2006	Cause No. 44019; Cause No. 42943; Cause No. 42767.	The rider recovers the difference between actual margins and the level of margins approved in the most recent rate case, as adjusted for changes in customer count.
Iowa	Gas	2006	Docket No. NOI-06-1 (Docket is not accessible online).	The Iowa Utilities Board examined decoupling for natural gas utilities in 2006. While the Board does not require utilities to decouple, utilities are allowed to apply for automatic adjustment mechanisms or other rate design changes on a case-by-case basis.
Kansas	Both	2008	Docket 08-GIMX-441-GIV.	The Kansas Corporation Commission will consider proposals from utilities that include decoupling on a case-by-case basis. No decoupling proposals have been approved for any utilities.
Maine	Both	2009 – Current mechanism in 2014	Me. Rev. Stat. title 35-A, §3195; Docket No. 2013-168.	There are statutory provisions allowing decoupling. The state's largest electric utility has a decoupling mechanism in place, which is a based on authorized per-customer revenue, adjusted for weather, determined by fixed costs from previous rate cases. Adjustments are made monthly. Recovery of any under-collection under the decoupling mechanism is subject to an annual cap set at 2 percent of distribution revenues. Under-collection amounts over the annual cap will be deferred for recovery in a subsequent year. No cap applies to the return of any over-collection.
Maryland	Both	2005 electric / 2007 gas	Case No. 9036; Case No. 9092; Case No. 9093.	The decoupling mechanism uses the actual, non-weather adjusted revenue to allowed distribution revenue, adjusted for net customers added by rate schedule. Utilities are allowed different maximum rate changes per month, with carry over potential.
Massachusetts	Both	2009 electric / 2011 gas	Docket No. D.P.U. 09-39; Docket No. D.P.U. 11-01; Docket No. D.P.U. 08-50-A; Docket No. D.P.U. 10-70.	One mechanism used by two utilities calculates adjustments based on a comparison of authorized revenue to actual revenue by class and caps adjustments at 1 percent of revenue with carryover to subsequent years. Another utility operates under a similar mechanism, although it includes

				recalculations of authorized revenues each year to account for capital additions and has an adjustment cap of 3 percent.
Michigan	Both	2010	Gas Utilities: Senate Bill 213 (2008); Docket No. U-15985; Docket No. U-15986; Docket No. U-15990. Electric Utilities: Senate Bill 438 (2017).	Michigan allows natural gas utilities and certain electric utilities (those serving less than 100,000 customers) to propose a decoupling mechanism for energy efficiency programs. The mechanism in place calculates adjustments using comparisons of authorized and actual non-fuel revenue per-customer, by class. It allows for the revenue changes from customer movement but does not include a weather adjustment clause.
Minnesota	Both	2007	Senate File 145 (2007); Senate File 550 (2009); Docket No. GR-08-1075; Docket No. CI-08-132; Docket No. GR-10-977.	In 2007, Minnesota enacted legislation requiring the Public Utilities Commission (PUC) to establish criteria and standards for decoupling. Legislation enacted in 2009 provided additional procedural options to the PUC for establishing decoupling criteria and standards. At least two utilities, CenterPoint Energy and Minnesota Energy Resources Corp., have decoupling mechanisms in place for natural gas customers.
Nevada	Gas	2007	Nev. Rev. Stat. §704.110; Nev. Admin. Code §704.953; Docket No. 09-04003.	Nevada law allows natural gas utilities to propose decoupling in general rate cases filed within one year of the approval of energy efficiency programs. The decoupling mechanism in place operates on a per-customer revenue basis and adjusts the actual revenue to meet the authorized revenue. The utility is authorized to make separate calculations for northern and southern regions of the state.
New York	Both	2007	Docket No 09-E-0588; Docket No. 09-E-0428; Docket No. 09-E-0715; Docket No. 09-E-0717; Case 03-E-0640; Case 06-G-0746.	Operates "rate plans" which set two-year revenue requirements with calculations for a third year. Most utilities can adjust yearly, while others are authorized to file for immediate adjustments if they exceed a specific amount. Electric and gas utilities are required to file proposals for true-up-based decoupling mechanisms in ongoing and new rate cases.

New Hampshire	Gas	2018	Docket No. DG 17-048, Order No. 26, 122 and Order No. 26, 149; Docket No. DE 15-137.	The decoupling mechanism allows for monthly adjustments based on usage, which are determined for residential and commercial customers separately. This mechanism replaced the LRAM in place prior to November 2018.
North Carolina	Gas	2005 and readjusted in 2013	Docket G-9 Sub 550B; Docket G-5 Sub 495.	Decoupling mechanism uses semi-annual adjustments based on differences between actual, non-weather adjusted, per-customer revenue with authorized per-customer revenue, by rate schedule.
Ohio	Electric	2012	Senate Bill 221 (2008); Docket No. 11-5905-EL-RDR.	Legislation authorizes the Public Utilities Commission to approve decoupling mechanisms proposed by electric utilities. Mechanisms in place calculate adjustments by comparing authorized distribution revenues and actual revenues for residential and small commercial classes. Adjustments are made annually and are capped at 3 percent for surcharges, with the ability to carry forward to subsequent years.
Oregon	Both	2002 gas / 2009 electric	Docket UG – 163; Docket UG – 152; Docket UG - 167; Docket No: UE 306.	One approved mechanism employs a strict revenue-per customer approach and expected revenues are reevaluated annually. Another mechanism applies a similar revenue-per-customer design that also permits earnings sharing over a certain point over the allowed return on equity. A third decoupling mechanism allows the utility to calculate adjustments based on the difference between actual, weather-adjusted, fixed cost revenue per customer and allowed revenue per customer for residential and small general service. This mechanism caps adjustments at 2 percent per year and does not allow carry over.
Rhode Island	Both	2011	House Bill 8082A and Senate Bill 2841A (2010); Docket No. 4206.	For gas utilities, the decoupling mechanism is an annual revenue-per-customer true-up that compares actual revenues with target revenues by adjusting infrastructure, safety and reliability expenses, and environmental response, along with other cost additions from the previous year. For electric utilities, the mechanism does not include an update of authorized revenues, but

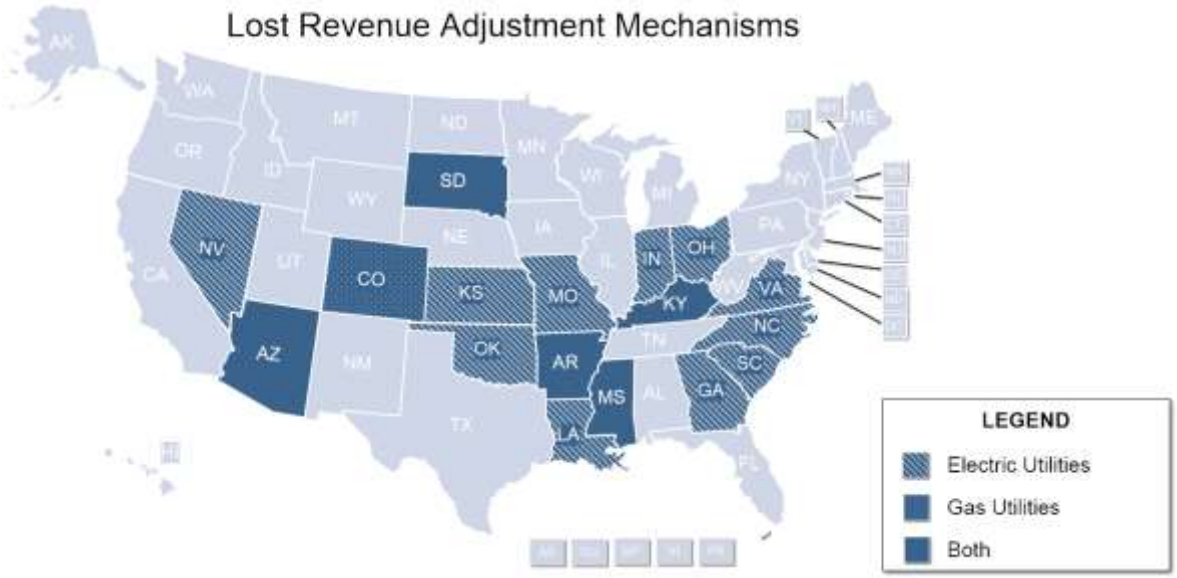
				instead compares actual and authorized distribution revenues to calculate adjustments annually.
Tennessee	Gas	2010	Docket No. 09-00183.	There is no policy in place for electric decoupling, however the Tennessee Valley Authority decided to make efforts to address the issue of lost contributions to fixed costs for distributors. In 2010, the Tennessee Regulatory Authority approved the Chattanooga Gas Co.'s request for an increased monthly charge for fixed costs to better align the interest of ratepayers and utilities in promoting energy efficiency. The mechanism is the Alignment and Usage Adjustment (AUA), which applies to residential and small commercial customer classes. A revenue per customer was calculated for the customer classes (Docket 09-00183), and each year, the actual revenue per customer is compared to the benchmark revenue per customer. The AUA was approved on a three-year trial and was extended pending a full report on the mechanism. The AUA remains in effect.
Utah	Gas	2010	Docket 10-057-T03.	The mechanism compares the general services class's actual revenues per customer with margin revenues per customer and caps surcharges at 5 percent and amortizations at 2.5 percent of gross revenues.
Vermont	Both	2006	30 V.S.A. § 218d.	Utilities are allowed to adjust rates annually based on forecasted costs and sales. The Public Services Board is allowed to establish alternatives to rate-making procedures for utilities.
Virginia	Gas	2008	House Bill 543 (2008); PUE-2008-00060; PUE-2009-00064; PUE-2009-00051.	Legislation requires the State Corporation Commission to approve conservation and ratemaking efficiency plans filed by natural gas utilities that include a decoupling mechanism if the mechanism is revenue-neutral. The approved mechanism makes monthly adjustments based on the difference in actual and authorized distribution revenue per customer.
Washington	Both	2007	Docket No. UG-060518, extended in Docket No.	Recovery from the difference between actual and authorized margin is capped at 45 percent and includes an earnings test. The mechanism also has

			UG-090135; Energy Independence Act.	adjustments for new customers and weather.
Wyoming	Gas	2009	Docket No. 30010-94-GR-08.	The approved mechanism calculates adjustments by comparing target and actual revenue per-customer for the general service class only.

LRAMs - Lost Revenue Adjustment Mechanisms

Policymakers in a number of states have turned to a lost revenue adjustment mechanism (LRAM) to remove financial disincentives associated with energy efficiency. Under LRAMs, utilities are allowed to recover lost revenues resulting exclusively from approved energy efficiency programs. Regulators are tasked with making calculations regarding the estimated energy savings connected with efficiency programs. These estimated savings are then used to determine the efficiency-related revenue shortfall a utility can recover. However, while LRAMs remove efficiency's disincentive of unrecognized revenue, they fail to remove the throughput incentive and continue to promote increased energy sales for higher profits.

Since LRAMs use complex calculations based on estimated savings, it is important that they are accompanied by reliable evaluation measures to verify a program's performance. While decoupling links a utility's recoverable profits to actual energy savings, LRAMs rely on predicted savings. Consequently, without frequent and accurate evaluations utilities could lose compensation for undervalued energy savings or overcharge customers for ineffective efficiency programs. South Carolina's LRAM addresses this concern by requiring a third party to evaluate utility efficiency programs and requiring lost revenue to be annually revisited once evaluation reports are available. Missouri has taken a slightly different approach and requires the commission to perform a "prudence review" at least every two years to verify the estimated energy savings used to calculate the utility's allowed revenue.



View the chart below for a full listing of state lost revenue adjustment mechanism policies.

Another major distinction between LRAMs and decoupling lies in the different ways they affect the throughput incentive. While decoupling completely separates profits from sales by adjusting the price of energy depending on sales, LRAM policies allow upward adjustments to recover efficiency costs but not downward adjustments when revenues exceed expectations. Consequently, while LRAMs remove efficiency's disincentive of unrecognized revenue, they fail to remove the throughput incentive and continue to promote increased energy sales for higher profits. Nevada provides an example of a state that sought to address this issue in its LRAM. The current mechanism approved by the Nevada Public Utilities Commission explicitly prevents utilities from over-earning. In recent years, this safeguard against overcollection has resulted in customer refunds for excess revenues.

Lastly, although LRAMs compensate utilities for reduced energy sales associated with efficiency programs, they do little to encourage investment in energy efficiency unless combined with other policies, such as energy efficiency resource standards and performance incentives, which are discussed below.

Lost revenue adjustment mechanisms are a viable policy for addressing concerns over lost revenue while allowing utilities to earn revenue beyond a predetermined amount. This policy approach can also bring policymakers, regulators and utilities together to address efficiency measures in cases where decoupling may not be possible due to varying stakeholder perspectives.

State-by-State Lost Revenue Adjustment Mechanisms

Seventeen states have adopted LRAMs, 11 of which have adopted mechanisms for electric utilities, one has adopted a mechanism for gas utilities, and five states have adopted mechanisms for both gas and electric utilities.

Terms used in the table include: demand side management (DSM).

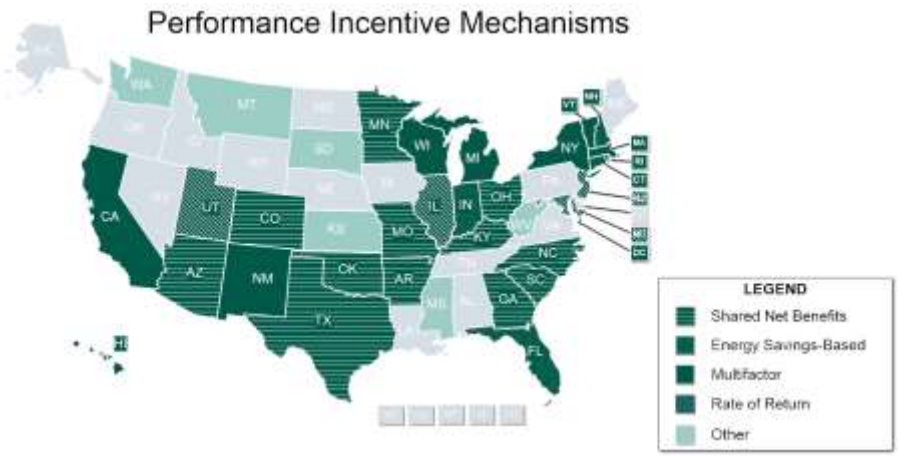
STATE	Type	YEAR	AUTHORITY	CURRENT MODEL SUMMARY
Arizona	Both	2012	Docket No. WS-02987A-09-0083; Docket No. T-02115A-04-0244; Docket E-01933A-12-0291; Docket No. E-01345A-11-0224.	Lost fixed costs are determined at the end of a rate case by dividing the allowed distribution revenue for each rate class by the adjusted test year billing estimates.
Arkansas	Both	2010	Docket 08-137-U, Order No. 14.	The Public Service Commission allows electric and gas utilities to award lost contributions to fixed costs that result from future utility energy efficiency programs. All investor-owned utilities can recover lost revenues as part of the annual energy efficiency program tariff.
Colorado	Gas	2008	Decision No. C14-0731; Decision No. C08-0248.	Utilities calculate their yearly fixed costs, subject to approval by the Public Utilities Commission. Lost fixed costs are multiplied by the annual DSM energy savings and recovered through a pre-approved cost adjustment. In 2014, the incentives were modified to state that the utility receives 5 percent of the economic benefits once 100 percent of the savings goals are achieved.
Georgia	Electric	2010	O.C.G.A. § 46-3A-9.	The approved or actual cost, whichever is less, of any certificated demand-side capacity option is recovered by the utility in rates, along with an additional sum as determined by the commission.
Indiana	Electric	2015	Senate Bill 412 (2015); Ind. Code Ann. §8-1-8.5-10.	Legislation authorized electric utilities to propose a rate adjustment mechanism to recover energy efficiency program costs. Utilities propose their own calculations for the LRAM but must account for changes in the number of programs between rate cases. An independent evaluator calculates efficiency savings and the lost revenue is recovered once or twice a year for the life of the measure or next rate case. The commission currently limits lost revenue recovery to either four years of the life of the measure, whichever is less, or until the rates

				are implemented pursuant to a final order in the utility's next base rate case, whichever occurs earlier.
Kansas	Electric	2007, 2011	Docket No. 08-GIMX-441-GIV; Docket 10-WSEE-775-TAR.	The Kansas Corporation Commission considers mechanisms proposed by utilities that include shared net benefits performance incentives on a case-by-case basis.
Kentucky	Both	1995	Ky. Rev. Stat. §278.285; Applied in subsequent PUC dockets including Case No. 2014-00271.	Utilities are allowed to recover the full cost of DSM programs. Energy savings are calculated based on engineering estimates for projects and multiplied by the number of projects, which are then multiplied by a lost revenue factor. The mechanism allows for recovery of lost revenues for a three-year period.
Louisiana	Electric	2014	Docket R-31106.	Based on a lost contribution to fixed cost factor, the mechanism calculates recoverable costs by multiplying a "factor" given to each class of customers by the projected energy savings for each program. These factors are calculated by dividing annual customer energy revenue by the energy sales. There is no cap on fixed cost recovery, but efficiency riders are capped at $75 monthly.
Mississippi	Both	2014	Docket No. 2010-AD-2.	Utilities use DSM-related energy savings, normalized for weather, multiplied by the base rate to customer classes to calculate lost revenues. Revenues are recovered annually with true-up adjustments.
Missouri	Electric	2013	Senate Bill 376 (2009); Case No. EO 2012-0142; Case No. EO-2012-0009.	Utilities earn a percentage of net benefits from DSM measures by calculating the gross annual energy savings through a monthly rider. Missouri PSC is tasked with performing reviews every two years to verify the utility's calculation of benefits from DSM projects.
Nevada	Electric	2009	Senate Bill 358 (2009); Docket No. 10-10024; Docket No. 10-10025.	Legislation directed the Public Utilities Commission to remove the financial disincentives for efficiency faced by utilities. In 2010, the PUC approved an LRAM for electric utilities. Lost revenues are estimated annually, but true-ups are allowed for single DSM implementation over several years, with collection suspended during periods of over-earning. Revenues are calculated on a customer class basis by taking estimated savings multiplied by the general rate. That number is then added to the estimated demand loss from DSM programs.

New Hampshire	Both	*Effective 2017-2018*	Docket No. DE 15-137: utility testimony, settlement agreement.	LRAM was replaced by decoupling in November 2018 (see Decoupling table).
North Carolina	Electric	2007	N.C. Gen. Stat. §62-133.9; Docket No. E-100 Sub 113.	Recovery of lost revenues is limited to 36 months and is subject to other limitations, such as reductions based on any net revenues from increased demand. Utilities can also receive a bonus incentive for recovery of program costs of 11.5 percent. Lost revenues are calculated by multiplying net savings from each DSM program by the billing rates, with fuel cost and variable operation expenses taken out.
Ohio	Electric	2007	Docket 08-920-EL-SSO; Docket 11-3549-EL-SSO; Docket 11-0351-EL-AIR.	LRAMs are determined on a case-by-case basis and lost revenues are recovered through a rider that can be collected for three years. Lost revenues are calculated through energy savings multiplied by the energy rate for each customer class. Variable costs are removed, and the resulting number is divided by the estimated energy sales for the upcoming year.
Oklahoma	Electric	2008	PUD Case No. 200700449.	Lost revenues are calculated annually and allowed until next rate adjustment or case. Revenues are calculated by multiplying energy savings by an embedded cost factor which takes the most recently approved cost factor divided by the energy used in a test period. Additional revenue recovery mechanisms will be determined on a case-by-case basis.
South Carolina	Electric	2008	S.C. Code Ann. §58-37-20; Docket No. 2008-251-E; Docket No. 2009-261-E.	Revenues are estimated annually and trued-up once evaluations are made. Lost revenues are calculated by multiplying energy savings by avoided costs, and can be collected for three years after installation.
South Dakota	Both	Gas 2009; Electric 2011	Docket NG09-001; Docket EL11-002.	Lost revenues are negotiated as a percent of approved budget spending and are limited to the year during which DSM program expenses are incurred. Energy savings are not used in the calculation of lost revenue but are used to verify cost-effective programs.
Virginia	Electric	2008	Va. Code §56-585.1; Case No. PUE-2010-00084.	Electric utilities can recover revenue reductions due to energy efficiency program implementation. Revenue recovery is limited by any offsetting sales and is subject to an industry verification.

Performance Incentives

Decoupling and LRAM both address direct disincentives for utility investment in energy efficiency programs by providing financial security and revenue recovery. However, these benefits are less direct and may be less financially appealing than those offered under the traditional model of regulation. For example, efficiency measures could be viewed as replacements for new capital investments, effectively eliminating an earning opportunity and decreasing a utility's overall revenue. For these reasons, policymakers, regulators and utility stakeholders have developed a variety of performance incentives that offer utilities financial compensation for energy saving programs.



View the chart below for a full listing of state performance incentive policies.

Although performance incentives vary from state to state, they can be classified, as the American Council for an Energy-Efficient Economy does, into four categories: shared net benefits (or shared savings) incentives, energy-savings-based incentives, multifactor incentives and rate-of-return incentives.

Shared Net Benefits: This incentive approach awards utilities a share of the net benefits from energy efficiency programs, as determined by a utility's avoided costs (the costs that the utility would incur by fulfilling the demand without energy efficiency). These benefits, along with the utility's efficiency program costs, form the incentive payment. Most shared net benefits incentives have a minimum threshold level at which the utility is entitled to a share of the benefits, along with a predetermined percentage that the utility is entitled to retain. Minnesota has given the Public Utilities Commission authority to operate a shared net benefits performance incentive. The mechanism has both a minimum threshold requirement to trigger the incentive—energy savings equal to 1.5 percent of retail sales—and a cap of 20

percent of net benefits. The percentage of benefits awarded is set annually and the incentive amount follows the amount of energy savings.

Energy-Savings-Based: With energy-savings-based incentives, utilities are rewarded for meeting and exceeding established energy savings targets. These targets can include demand savings, lifetime savings or other measures, and are often tied to statewide energy efficiency resource standard (EERS) policies. This incentive is typically determined as an amount that a utility can earn as a percentage of the total efficiency program cost. Additionally, as with shared net benefits, performance target incentives are typically withheld until a minimum savings threshold is achieved. The incentive mechanisms employed in Connecticut, Indiana and New Hampshire follow this approach. In Connecticut, electric and gas utilities are able to earn incentives for efficiency offerings. Each year, the Energy Efficiency Board reviews the past year's energy savings compared to established goals and determines a performance incentive for utilities for achieving or exceeding the goals. The incentive can be between 2 and 8 percent of the program costs, and the savings threshold that utilities must meet to earn the minimum incentive is 75 percent.

Rate-of-Return: Under rate-of-return incentives, utilities are allowed to earn a rate-of-return based on their energy efficiency spending. This type of incentive connects demand-side efficiency spending to supply-side investments, such as generation and transmission. Rate-of-return incentives are employed in at least four states—Illinois, Maryland, New Jersey and Utah. Utah's incentive was established through legislation enacted in 2016, allowing Rocky Mountain Power, the state's largest investor-owned utility, to capitalize demand-side management costs and amortize the costs over 10 years, and to recover those costs through rates. Similarly, Maryland's utility business model allows utilities to capitalize their investments with a return on investment based on the weighted average cost of capital and costs are amortized over a five-year period.

Multifactor: This approach to performance incentives has been adopted by a number of states looking to compensate utilities for efficiency programs while also rewarding them for achieving program goals beyond energy savings. Program goals can include peak demand reductions, local job creation or improved customer service. As with the other incentives, the multifactor approach can establish a minimum threshold requirement and set a percentage of allowable return. California's incentive allocates earnings among four categories—energy efficiency resource savings, ex ante review process performance, codes and standards advocacy program and non-resource program. Each category has separate incentive caps and eligibility requirements.

Through the adoption of various incentives, state policymakers and regulators have gained experience allowing them to tailor incentives for their individual circumstances and goals. This performance-based approach assures that utilities are rewarded for realized energy savings, not utility expenditures. Additionally, states have imposed penalty provisions that act to increase utility motivation and stress the importance of energy efficiency.

State-by-State Performance Incentives

At least 35 states and Washington, D.C. have developed utility performance incentives for demand-side management (DSM) and EE projects through the legislature or public utilities commission. Of these states, 12 have shared net benefits incentives, four have energy savings-based incentives, nine and Washington, D.C. have multifactor incentives and four have return on investment incentives. Additionally, six states have implemented multiple incentives types or have not specified the type of incentive.

STATE	TYPE	YEAR	AUTHORITY	CURRENT MODEL SUMMARY
Arizona	Shared Net Benefits	2005, modified in 2013 and 2014.	Docket No. E-01345A-12-0224 Decision No. 74406; Docket No. E-011933A-12-0291 Decision No. 73912.	Incentive applies to two major IOUs—Arizona Public Service (APS) and Tucson Electric Power (TEP). To qualify, utilities must reach a threshold of 85 percent of the energy efficiency savings goal. **APS** has a tiered incentive that is based on a percentage of the net benefits from energy savings and is capped as a tiered percentage of program costs. **TEP** receives 8 percent of net benefits. Both utilities' incentives are capped at $0.0125 per kilowatt hour saved.
Arkansas	Shared Net Benefits	2010	Docket No. 08-137-U.	To qualify for the incentive, utilities must reach a threshold of 80 percent of the energy savings target for a given year. The incentive amount is up to 10 percent of the net benefits. Incentive caps range from 4 percent to 8 percent of program budgets.
California	Multifactor	Current incentives adopted in 2012	CPUC Rulemaking 12-01-005, Decision 13-09-023.	No minimum energy savings threshold is specified. Instead, incentive amounts are a linear function of net lifecycle savings

				multiplied by the earnings rate. Incentive earnings are allocated among four categories: Energy Efficiency Resource Savings; Ex Ante Review Process Performance; Codes and Standards Advocacy Programs; and Non-Resource Program. Incentive caps vary by category: energy efficiency resource savings—9 percent of resource program expenditures; ex ante review process performance—3 percent of resource program expenditures; codes and standards programs—12 percent of approved program expenditures; non-resource program management fee—3 percent of non-resource program expenditures.
Colorado	Shared Net Benefits	2008, updated in 2018.	Colo. Rev. Stat. §40-3.2-104; Public Service Company of Colorado Proceeding No. 17A-0462EG, Decision No. C18-0417.	Incentives have a threshold requirement of 80 percent of net energy savings goal, or 400 gigawatt hours of energy savings. A 2018 PSC decision established that a $3M incentive will be earned in two installments. The first half will be given when 400 GWh of savings (or 80 percent of the goal) is reached, and the second half will be given when the 450 GWh of savings (or 90 percent of the goal) is reached. Total incentives are capped at $18M.
Connecticut	Energy Savings-Based	1998	Conn. Gen. Stat. §16a-49.	The incentive ranges from 2 to 8 percent of the program costs before taxes. The threshold for earning the minimum incentive (2 percent) is 75 percent. In annual hearings, the Energy Efficiency Board reviews the past year's results relative to the established goals and determines a performance incentive.
District of Columbia	Multifactor	2008	DC Clean and Affordable Energy Act of 2008 §202; DCSEU 2017 contract.	Legislation enacted in 2008 requires contracts between the District Department of the Environment and the Sustainable Energy Utility (SEU) to be performance-based and to provide financial incentives if benchmarks are met, and financial penalties if the contractor fails to meet the required performance benchmarks. The 2017 contract

				established performance targets for the next five years.
Florida	Energy Savings-Based	2008	House Bill 7145 (2008); Fla. Stat. Ann. §366.82.	The Public Service Commission is authorized to allow investor-owned utilities to earn an additional return for exceeding energy efficiency and conservation goals. Utilities may earn an additional return of up to 50 basis points for exceeding 20 percent of the annual load-growth through energy efficiency. No utilities have requested the additional return.
Georgia	Shared Net Benefits	2010	Ga. Code Ann. §46-3A-9; Georgia Power's 2013 Integrated Resource Plan.	Georgia allows electric utilities to recover costs an additional sum for approved programs. For Georgia Power, the Commission approved an incentive of 8.5 percent of actual net benefits of electricity savings for achieving 50 percent or more of the kilowatt hour projected savings. If the additional sum exceeds program costs, the portion of the total that exceeds program cost is limited to 4 percent net benefits.
Hawaii	Multifactor	2009	House Bill 1464 (2009); Docket No. 2010-0037; Senate Bill 2939 (2018).	2009 legislation established the state's Energy Efficiency Portfolio Standard and allowed the Public Utilities Commission to establish incentives and penalties based on performance in achieving the standard. Additionally, legislation enacted in 2018 requires the Public Utilities commission to establish performance-based rates for Hawaiian Electric Company by 2020. Hawaiian Electric Company (HECO) has multifactor performance incentives built into its contract with Hawaii Energy to administer its efficiency programs. The contract proposes targets for each indicator. Each target includes a 75 percent minimum and 125 percent maximum achievement amount. Financial

				incentives are based on percentages allocated to each indicator.
Illinois	Rate-of-Return	2016, effective 2018.	Senate Bill 2814 (2016).	Legislation provides either increased or decreased return on investment to electric utilities based on their performance relative to statutory efficiency goals.
Indiana	Energy Savings-Based	2009	Ind. Code §8-1-8.5-10; Indiana Utility Regulatory Commission Cause No. 44645.	The Indiana Utility Regulatory Commission is authorized to approve performance incentives. However, as of March 2019, only one incentive has been approved. The URC approved performance incentives for Vectren Energy with a threshold of 75 percent energy savings goals. The incentive ranges from 5 to 10 percent of the value of the net benefits, depending on the achievement level.
Kansas	Shared Net Benefits/Rate-of-return	2007	Docket No. 08-GIMX-441-GIV; Docket No. 10-WSEE-755-TAR.	The Kansas Corporation Commission reviews proposals from gas and electric utilities for shared net benefits incentives on a case-by-case basis. The commission also allows for a rate-of-return of 0.5 percent to 2 percent of authorized capital investments for energy efficiency investments.
Kentucky	Shared Net Benefits	2011	Ky. Rev. Stat. §278.285(1).	Incentives have no threshold or cap and a range from 10 percent to 15 percent of net resource savings, excluding public education and pilot programs.
Maryland	Rate-of-Return	2007	Case No. 9111, Order No. 81937; Md. Public Utilities Code Ann. §7–211; Senate Bill 184 (2017).	The Public Service Commission is authorized to approve financial incentives for gas and electric utilities to promote energy efficiency and conservation programs. No incentives have been approved. Maryland also allows utilities to rate base and capitalize their investments with a return on investment based on the weighted average cost of capital. The costs are amortized over a five-year period. While the rate-of-return calculation in not directly tied to energy savings thresholds, utilities are required to meet energy savings performance requirements.

Massachusetts	Multifactor	2008	Mass. Gen. Laws Ann. ch. 169 §21(b)(2); DPU Order 11-120-A.	The incentives are earned as a return on the three-year plan spending for meeting program goals. The incentive is based on a combination of elements including energy savings, benefit-cost analysis and market transformation results. The current performance incentive parameters can be found in DPU order 1-29-19, files 18-110 through 18-119.
Michigan	Multifactor	2008, updated in 2016.	Mich. Comp. Laws §460.1001-1195; updated by Senate Bill 438 (2016).	Michigan has a multifactor performance incentive in place for its investor-owned utilities. The mechanism includes savings-based metrics and program goals, such as expanding low-income programs, promoting deep energy savings and reducing peak demand. Legislation in 2016 updated the state's performance incentive for 2017-2021 and established tiers of eligibility when utilities achieve 1.25 percent and 1.5 percent annual savings. The bill increased the maximum incentive that utilities can qualify for from 15 to 20 percent of spending if their annual savings exceed 1.5 percent of retail sales. The incentive amount is determined using a multifactor approach. The incentive includes the calculation of the Long-Life Equipment Savings Multiplier, which is a 10 percent savings multiplier awarded to measures installed with a measure of life of 10 years or more.
Minnesota	Shared Net Benefits	1999	Min. Stat. Ann. §216B.241; Docket No. E,G-999/CI-08-133.	The incentive increases as the percentage of savings of retail sales increases. At savings of 1.5 percent of retail sales, electric utilities will earn an incentive of 7 cents per kilowatt hour saved, and gas utilities will earn an incentive of nine dollars per thousand cubic feet saved. The percentage of net benefits to be awarded to each utility at different energy savings levels is set at the beginning of each year. The incentive is capped at 20 percent of net benefits

				on the amount of incentive that may be earned.
Mississippi	N/A	2010	Docket No. 2010-AD-2 Rule 29.	Authorized but not implemented.
Missouri	Shared Net Benefits	2009	Senate Bill 376 (2009).	Incentives are on a tiered or graduated scale for savings, ranging from a threshold of 70 percent to 130 percent of cumulative three-year savings target. Incentives vary based on achievement of savings goal. A utility achieving 70 percent of savings goal entitled to 4.6 percent of net benefits, and up to 6.19 percent of net benefits for achieving 130 percent or more of the savings target. Maximum incentive based on percentage of shared net benefits is capped on a utility-by-utility basis with no statewide cap on dollar amount.
Montana	N/A	2013	Mont. Code Ann. §69-3-712.	Allows for the Public Service Commission to add 2 percent to the authorized rate-of-return for demand-side management investments. The incentive has not yet been approved for any utility.
New Hampshire	Energy Savings-Based	2000	Order No. 23,574; Order No. 25,932, Docket No. 15-137; Order No. 26,095, Docket No. 17-136.	New Hampshire has a savings target of 5.5 percent of total sales. The incentive is capped at 6.875 percent and is in effect through 2019. A working group was formed in 2018 to review potential incentive calculation methodologies to further promote achievement of the state's energy efficiency resource standard goals.
New Jersey	Rate-of-Return	2015	Docket No. EO14080897 (2015); Docket No. EO17030196 (2017); Docket Nos. GO18101112 and EO18101113 (2018).	The Board of Public Utilities authorized Public Service Electric and Gas (PSE&G) to implement a $95 million electric and gas energy efficiency program in 2015, and authorized PSE&G to recover program costs through a Green Program Recovery Charge on all electric rate schedules using a proportional cost basis. The utility can amortize costs over a seven-year period. PSE&G's revenue requirement associated with its energy efficiency portfolio included a return on investment for the

				amortization of the regulatory asset set at the utility's weighted average cost of capital. Expenses are initially estimated, then trued up the next year during the annual review of the program recovery charge. In 2018, PSE&G proposed an energy efficiency portfolio for 2020 through 2025 at a cost of $2.5 billion and proposed that it be authorized to earn a return on its net investment using the weighted average cost of capital. The mechanism is not tied to performance on energy savings or other targets.
New Mexico	Multifactor	2013	House Bill 267 (2013); Case No. 12-00317-UT; Case No. 15-00119-UT. El Paso Electric: Case No. 13-00176-UT. Southwestern Public Service: Case No. 15-00119-U. Public Service company of New Mexico: Case No. 14-00310-UT.	Utilities can propose an incentive mechanism that is based on satisfactory program performance. At least three utilities currently have profit incentives. **El Paso Electric's** incentive is set at 7 percent of a 2016 budget of approximately $5.8 million. **Southwestern Public Service** earns a base level incentive of 6.8 percent on a budget of approximately $11.5 million, based on a minimum savings threshold. **Public Service Company of New Mexico's** incentive is based on a linear progression of cumulative savings towards the 2020 goal. The incentive is conditional on achieving energy savings of 6 percent of 2005 retail sales and is approximately 7.1 percent of program costs.
New York	Multifactor	2008, REV proceeding initiated in 2014.	New York Energy Efficiency Portfolio Standards; Reforming the Energy Vision; PSC Case 14-M-0101 (February 26, 2015, and May 19, 2016 orders); PSC Cases 16-E-0060, 16-G-0061 and 16-E-0196	New York is examining potential changes to the utility regulatory structure in the state and associated incentives through the Reforming the Energy Vision (REV) initiative. The Public Service Commission issued its Track One and Track Two Orders in 2015 and 2016. Track One outlined broad policy and implementation frameworks, and Track Two addressed utility

			(January 25, 2017 orders).	ratemaking items, including performance incentives, or earning Adjustment Mechanisms (EAMs). Several utilities, including Consolidated Edison Company of New York have EAMs in place.
North Carolina	Shared Net Benefits	2013	Senate Bill 3 (2007); Docket No. E-2 Sub 931; Docket No. E-7 Sub 831.	Legislation allows the Public Utility Commission to approve incentives for public utilities adopting and implementing new programs. Duke Energy Progress has an incentive in place that allows the utility to earn a percentage of avoided costs, which are capped as a percentage of actual program costs. The cap ranges from 5 to 15 percent. The incentive mechanism allows Duke to earn 8 to 13 percent of the net present value of the net savings from demand side management programs.
Ohio	Shared Net Benefits	2008	Docket No. 11-5028-GA-UNC; Docket No. 08-920-EL-SSO.	Incentives are included in an annual rider with a maximum payment of 10-15 percent of program costs if at least 65 percent of target savings are achieved.
Oklahoma	Shared Net Benefits	2008	N/A	The incentive has a threshold of 85 percent of net goal savings and is capped at 15 percent of net benefits.
Rhode Island	Multifactor	2005 (electric) and 2007 (gas).	Docket No. 4366, Energy Efficiency Program Plan 2013; Docket No. 4366, Order No. 20911; Docket No. 4527, Energy Efficiency Program Plan 2015; Docket No. 4527, Order No. 21854.	The minimum threshold requirement is 75 percent of annual energy and demand savings goal. Target base incentive is 5 percent of spending budget. From 75 to 100 percent of the goal, the incentive ramps up from 1.25 percent of the spending budget to 5 percent, and from 100 to 125 percent of each goal, the incentive is 5 percent of the spending budget multiplied by the percentage achieved. The Public Utilities Commission authorized 30 percent of the target electric program incentive to be based on demand savings, and the remaining 70 percent to be based on energy savings.

South Carolina	Shared Net Benefits	2010	S.C. Code Ann. §58-37-20; Docket No. 2009-261-E.	Incentives are based on the net present value of each program using the Utility Cost Test.
South Dakota	N/A	2008	Docket No. EL 07-015; Docket No. NG 09-001; Docket No. GE 10-001; NorthWestern Energy Demand Side Management Plan 2009.	South Dakota has approved performance incentives which are incorporated in the state's LRAM. Utilities are awarded a flat-rate or fixed percentage bonus (depending on the utility) if they meet their efficiency goals. The fixed percentage is intended to cover lost revenues resulting from efficiency programs.
Texas	Shared Net Benefits	2007	Tex. Utilities Code Ann. §39-905; Public Utility Commission of Texas, Electric Substantive Rules §25.181. h	Texas has a threshold requirement of 100 percent of savings goal, with incentives of 1 percent of the net benefits for every 2 percent exceeding of demand reduction goal. Maximum incentive is 10 percent of a utility's total net benefits.
Utah	Rate-of-Return	2016	Senate Bill 115 (2016).	Utah authorizing Rocky Mountain Power (RMP), the state's largest IOU, to capitalize on demand-side management costs and amortize the costs over a period of 10 years, and to recover these costs through rates. This mechanism is not tied to performance on energy savings or other targets.
Vermont	Multifactor	2000	30 V.S.A. § 209.	Efficiency Vermont (EVT), the statewide energy efficiency utility, received performance compensation based on the attainment of three-year performance targets, or quantitative performance indicators (QPIs). QPIs are established by the Vermont Public Utility Commission during Demand Resources Plan proceedings, which are conducted every three years. Some QPIs are minimums that result in reductions to EVT's compensation if not met. Others scale up with increased performance. Incentive structure was based on prior three-year performance period. The PUC is conducting the Demand Resources Plan proceeding for the 2018-2020 performance period.
Washington	N/A	N/A	Wash. Rev. Code § 19.285.060(4)	Electric investor-owned utilities can propose incentives for exceeding the

				biennial conservation targets. No incentive mechanism is in place.
West Virginia	N/A	N/A	N/A	Authorized but not implemented.
Wisconsin	Multifactor	Offered between 2015-2018.	Docket No. 9501-FE-116, Order No. 198182.	Utilities can propose incentives as part of their rate cases. A contract between the Statewide Energy Efficiency and Renewables Administration and Chicago Bridge and Iron created incentives for customer satisfaction and achievement of energy savings goals. The mechanism includes penalties for under-achievement on all metrics and a $750,000 cap on payment in a four-year period. The incentive was available through 2018.

Conclusion

The three previous tabs have described policy and regulatory options that address the barriers to utility investment in energy efficiency programs. Decoupling addresses the risk of lost revenues due to efficiency investments while performance incentives compensate utilities for lost earnings from reduced capital investments. Lost revenue adjustment mechanisms also remove the financial disincentives associated with energy efficiency, however, they fail to remove the throughput incentive and continue to promote increased energy sales. The issue of capital investment bias, not addressed by the policies listed here, is also being discussed in a few states that are attempting to rework their regulatory models to better align customer and utility goals. Minnesota's e21 and New York's REV process are examples of state efforts around this issue. Although there is no one-size-fits-all approach, many states are gaining familiarity with the benefits of energy efficiency policies and are working to create lasting programs that help utilities fairly weigh efficiency investments against capital intensive alternatives.

Resources

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    - The Old Model Isn't Working: Creating the Energy Utility for the 21st Century, (Washington, D.C.: 2011)
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