ORIGINAL

000109360

SOUTHWEST GAS CORPORATION

RECEIVED

2010 MAR 26 P 2: 28

AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED

MAR 26 2010

DOCKETED BY

March 25, 2010

Docket Control Office
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007-2996

Subject: Docket Nos. E-00000J-08-0314 and G-00000C-08-0314

Southwest Gas Corporation herewith submits for filing an original and fifteen (15) copies of its Notice of Filing Comments and Responses to the Arizona Corporation Commission's Notice of Inquiry issued February 23, 2010 in the above-referenced dockets.

Respectfully submitted,

Debra Gallo

Debra S. Gallo
Director / Government & State Regulatory Affairs

Enclosure

5241 Spring Mountain Road / Las Vegas, Nevada 89150-0002
P.O. Box 98510 / Las Vegas, Nevada 89193-8510 / (702) 876-7011
www.swgas.com

RECEIVED

BEFORE THE ARIZONA CORPORATION COMMISSION

2010 MAR 26 P 2: 28

AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE ARIZONA CORPORATION COMMISSION'S INVESTIGATION OF REGULATORY AND RATE INCENTIVES FOR GAS AND ELECTRIC UTILITIES	DOCKET NO. E-00000J-08-0314 G-00000C-08-0314 **NOTICE**

NOTICE OF FILING COMMENTS AND RESPONSES TO THE ARIZONA CORPORATION COMMISSION'S NOTICE OF INQUIRY

Southwest Gas Corporation hereby provides notice of filing its response to the Arizona Corporation Commission's Notice of Inquiry (NOI). The responses of Southwest Gas to the fifteen questions presented in the NOI are enclosed herewith as Attachment A. In addition to responses, Southwest Gas offers the following comments:

Utilities Need to Be Indifferent to their Level of Sales

As stated by Southwest Gas throughout the course of the energy efficiency workshops, the current Arizona regulatory model needs to change in order to successfully implement and maximize the energy efficiency potential within the state. The Commission needs to abandon its reliance upon volumetric sales as the means for utilities to recover Commission-approved fixed costs. Until this reliance upon volumetric sales is eliminated, Arizona will not maximize its energy efficiency potential because the utility's interest in the level of their sales is too great. Utilities must be neutral in their preference for acquiring supply- and demand-side resources. Southwest Gas' proposed revenue decoupling mechanism[1] eliminates its reliance on volumetric sales to recover Commission-approved fixed costs, and will result in the alignment of Southwest Gas' interests with its customers' interest – the pursuit of all cost-effective energy efficiency.

Revenue Decoupling is Widely Accepted

As noted in the Commission's NOI, several states have adopted revenue decoupling.[2] In fact, a total of 40 natural gas and electric utilities across 17 states have approved some form of revenue decoupling.[3] In addition, a total of 21 other states have eliminated the link between fixed cost recovery and sales through other rate stabilization mechanisms.[4]

The policy objective of eliminating a utility's reliance upon volumetric sales has been and is currently being pursued at the federal level. For instance, section 532 of the Energy Independence and Security Act of 2007 requires state public service commissions to "align utility incentives with the deployment of cost-effective energy efficiency" and consider "separating fixed-cost revenue recovery from the volume of . . . sales service provided to the customer" and "adopting rate designs that encourage energy efficiency for each customer class." More recently, section 410 of the American Recovery and Reinvestment Act conditioned the release of state energy grants upon the commitment that policies are adopted to ensure "utility financial incentives are aligned with helping their customers use energy more efficiently" and "timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings…."

---

[1] Southwest Gas' proposed revenue decoupling mechanism refers to the non-gas revenue approved by the Commission in a general rate case, which is used to cover its expenses. Southwest Gas' preferred mechanism is more fully described in the responses to the NOI questions, specifically response to question #2.

[2] In addition to Arizona, Southwest Gas conducts gas operations in California and Nevada, both of which have approved revenue decoupling mechanisms.

[3] *See* Attachment B, Pamela G. Lesh, *Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling, A Comprehensive Review* (2009).

[4] *See* Attachment C, American Gas Association Map of States with Non-Volumetric Rate Designs for Natural Gas, as of January 2010.

This policy objective was also recognized on a local level when one of the stated purposes of the above-captioned docket was to address rate design modifications to promote energy efficiency investment standards as required by the Energy Independence and Security Act of 2007. Furthermore, stakeholders, including Southwest Energy Efficiency Project (SWEEP) and National Resource Defense Council (NRDC) have been very outspoken in their belief that a utility's reliance upon volumetric sales needs to be eliminated and that revenue decoupling is the optimal regulatory tool to accomplish this objective.

Ralph Cavanagh of NRDC advocates that the necessary business model for successfully implementing energy efficiency contains three pillars:

- ✓ Timely cost recovery of conservation and energy-efficiency program costs.
- ✓ Removal of the financial disincentive associated with utilities reliance upon volumetric sales as the means to recover Commission-approved fixed costs, resulting in the alignment of customer and utility interests by severing the relationship between sales and profits (i.e. revenue decoupling).
- ✓ Performance incentives. Simply removing the financial disincentive will not maximize performance; utilities need to be rewarded through performance incentives in order to maximize energy efficiency potential. Similar to how utilities currently have an earnings opportunity with respect to plant they place into service, utilities should have an earnings opportunity on the investment they make in energy efficiency. The application of performance incentives (or an earnings opportunity) will facilitate making utilities neutral in their preference in acquiring supply- and demand-side resources.

Southwest Gas supports the business model advocated by Mr. Cavanagh and has reinforced this business model during recent energy-efficiency workshops and meetings with key stakeholders. The Commission currently has a process whereby Southwest Gas receives timely cost recovery for costs associated with its conservation and energy-efficiency programs. Indeed, the major obstacle for Southwest Gas is the need to eliminate its reliance on volumetric sales to recover Commission-approved fixed costs. Southwest Gas firmly believes that with the implementation of a proposed revenue per customer decoupling mechanism, the financial disincentive for implementing energy-efficiency programs will be removed and Southwest Gas will be indifferent to its level of sales. Upon becoming indifferent to its level of sales, Southwest Gas will be able to change its business focus from selling natural gas to assisting customers in pursuing all cost effective energy efficiency – thus aligning utility and customer interests.

Common Misconceptions Regarding Decoupling

Although discussed in more detail in the responses to some of the questions set forth in the NOI, there are several misconceptions about revenue decoupling that are worthy of mention here.

- Revenue decoupling will result in the utility over-earning.
  - ✓ **False.** Revenue per customer decoupling does not, in and of itself, facilitate a utility to over earn. To the contrary, revenue per customer decoupling benefits customers by protecting against a utility collecting more revenue per customer than what the Commission authorized in its last general rate case proceeding. With revenue per customer decoupling, the utility's actual profits become even more closely tied to its management of costs, and the only way a utility could ever over earn is if it experienced a significant decline in costs following a general rate case. Coincidentally, this provides additional incentive for a utility to efficiently manage costs, which benefits customers through potential rate

decreases as the reductions in costs will be passed on to customers in a subsequent rate case.

- Revenue decoupling will discourage conservation by customers.
  - ✓ **False**. Revenue per customer decoupling does not establish "fixed rates" that make utility bills independent of actual consumption. Decoupling allows the Commission to retain the current volumetric pricing scheme (recovering fixed costs in variable rates) to ensure customers receive the price signals intended by the Commission. The result is the use of small, regular rate adjustments to ensure against over- or under-recovery of the utility's Commission-approved fixed costs. Also, utilities recover the decoupling true-up consistent with Commission policy by having those who use more, pay more of the true-up charge. In addition, revenue decoupling preserves the assumptions made by the Commission in the utility's last general rate case. Therefore, customers pay no additional costs beyond those approved by the Commission and the decoupling mechanism only permits utilities to recover the authorized revenue per customer approved by the Commission – nothing more.
- Revenue decoupling will negatively impact customers through large surcharges.
  - ✓ **False**. "Decoupling adjustments tend to be small, even miniscule."[5] Based upon the data contained in the revenue decoupling report prepared by Southwest Gas following its last general rate case, the average monthly bill impact between 2003-2008 would have been $0.13, or less than a penny a day. Ms. Lesh, in her

[5] *See* Attachment B, Pamela G. Lesh, *Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling, A Comprehensive Review* (2009).

comprehensive review of decoupling mechanisms, concludes that "decoupling adjustments tend to be small, even miniscule." Her report further illustrates that a majority of the monthly adjustments from decoupling mechanisms for natural gas utilities were less than 1 percent. The data contained in both Southwest Gas' and Ms. Lesh's reports provide overwhelming empirical evidence supporting the conclusion that the potential bill impact from revenue decoupling is minimal and is significantly less than the potential $0.15 per therm variation that Southwest Gas customers could experience with gas costs recovered through its fuel adjustment provision. In addition, revenue per customer decoupling protects customers from Southwest Gas collecting more revenue per customer than what the Commission authorized – even when it is colder than normal. This protection does not exist under the current Arizona regulatory structure.

CONCLUSION

The key to granting Arizona customers access to all cost-effective energy efficiency is revenue decoupling. Implementation of revenue decoupling makes utilities indifferent to their level of sales, thereby removing the financial disincentive associated with utilities implementing successful energy efficiency programs. There is simply no downside to implementing revenue decoupling in Arizona. Revenue decoupling establishes a ceiling and a floor with respect to the amount of revenue per customer the utility is permitted to recover; customers benefit from the protection revenue decoupling provides by ensuring utilities never collect more revenue per customer than what was authorized by the Commission; utilities recover the decoupling true-up consistent with Commission policy so that those who use more energy, pay a greater share of the true-up; and revenue decoupling enables utilities to change their business focus from selling their product to increasing customer end-use efficiencies. Indeed, revenue decoupling is a win-win for customers and utilities.

DATED this 26th day of March 2010.

SOUTHWEST GAS CORPORATION

Justin Lee Brown, Esq.
5241 Spring Mountain Road
Las Vegas, Nevada 89150
Tel: (702) 876-7183
Fax: (702) 252-7283
E-mail: Justin.Brown@swgas.com

ATTACHMENT A

Responses of Southwest Gas Corporation to the Arizona Corporation Commission Notice of Inquiry Docket Nos. G-00000C-08-0314 and E-00000J- 08-0314

1. **What financial disincentives to utilities are created by the implementation of energy-efficiency measures?**

The predominant financial disincentive is that Southwest Gas relies upon volumetric sales in order to recover its Commission-approved fixed costs of operating its distribution system. Accordingly, Southwest Gas' financial health is directly tied to the amount of gas used by its customers and it has a direct financial incentive to encourage increased, not decreased, consumption among its customers. As noted by Lisa Schwartz of Regulatory Assistance Project in her recent article entitled *The Role of Decoupling Where Energy Efficiency Is Required By Law*, this "structural conflict is at best paradoxical. At worst, it makes utilities adversaries instead of motivated partners in the myriad of venues where energy efficiency goals and activities are hammered out...."[1] These venues include state and federal processes to improve building codes and appliance standards, customer contact and referrals, and consumer education or market transformation efforts.

Arizona's current regulatory structure enables Southwest Gas to increase its profitability primarily in one of two ways: (1) reducing expenses; or (2) increasing sales, or a combination thereof. Indeed, a financial disincentive exists when Southwest Gas is required to reduce sales due to energy efficiency mandates, when it relies upon sales as a means to increase profitability. To remove the financial disincentive, the Commission needs to remove "increasing sales" as an option for increasing profitability. With revenue per customer decoupling[2] a utility can only increase its profits by reducing expenses, thus resulting in utilities becoming indifferent to their level of sales. Consequently, Southwest Gas will be afforded a realistic opportunity to become a motivated partner in the myriad of venues where energy efficiency goals and activities are addressed.

2. **Should the Commission consider a decoupling or decoupling-like mechanism that would allow Companies to recover weather-adjusted fixed costs that are lost as a result of energy efficiency programs that drive conservation? If so, why?**

No. Such a mechanism does not make utilities completely indifferent to their level of sales, and will result in only mitigating the current financial disincentive, not eliminating

---

[1] *See* Attachment D, Lisa Schwartz, *The Role of Decoupling Where Energy Efficiency Is Required By Law* (September 2009).

[2] Southwest Gas' proposed revenue decoupling mechanism refers to the non-gas revenue approved by the Commission in a general rate case, which is used to cover its expenses.

it. As noted in the prefatory comments, the necessary business model for successfully implementing energy efficiency includes a mechanism that completely removes the financial disincentive, such that utilities become totally indifferent to their level of sales.

Southwest Gas supports, and recommends the Commission implement, a revenue per customer decoupling mechanism that compares and adjusts for differences between authorized revenue per customer established in a general rate case to actual, non-weather adjusted, revenues per customer. Such a mechanism establishes a ceiling and a floor with respect to the revenue per customer collected by the utility. Revenue per customer decoupling also offers protections to customers that do not exist under the current Arizona regulatory model - ensuring that the utility does not collect more revenue per customer than what the Commission-authorized.

3. If you believe the Commission should adopt such a mechanism, how should it be structured?

As noted in response to question #2, Southwest Gas supports, and recommends the Commission implement, a revenue per customer decoupling mechanism that compares and adjusts for differences between authorized revenue per customer to actual, non-weather adjusted, revenues per customer. However, Southwest Gas also recognizes that the operating characteristics of each utility should be taken into consideration when determining the structure of a revenue decoupling mechanism and there may not be a one-size fits all mechanism that is optimal for all Arizona utilities.

a. Should certain customer classifications be exempt?

No. The intent should be to have the decoupling mechanism apply t all customer classes. In order to completely make Southwest Gas indifferent to its level of sales, the intent should be to include all customer classifications. However, Southwest Gas recognizes that some customer classifications may already be effectively decoupled through rate design or the characteristics of certain customer classes may warrant exemption from a mechanism. These issues can and should be dealt with on a case-by-case basis during the implementation of a decoupling mechanism.

4. How should weather-related changes in customer usage be treated? Should they be excluded and if so, how?

No, weather-related changes should not be excluded. The necessary business model for successfully implementing energy efficiency includes a mechanism that completely makes the utility indifferent to its level of sales. If weather-related changes are not included, utilities are not totally indifferent to their level of sales. More importantly, customers are not afforded the complete protection that a decoupling mechanism that captures weather-related changes offers. For instance, if weather-related changes are not included, Southwest Gas could still collect more revenue per customer during a colder-than-normal winter. Implementation of a revenue decoupling mechanism that includes weather-related changes prevents such a result.

Including weather-related changes symmetrically reduces risk for customers and utilities– as customers only pay (and utilities only receive) the Commission-authorized revenue approved in the last general rate case, regardless of colder- or warmer-than-normal weather. Furthermore, weather normalization adjustment provisions have been in place for over 30 years and no state commission that approved weather normalization adjustments has ever reversed itself and retracted the mechanism.[3]

5. What mechanism should be used for recovery of unrecovered fixed costs associated with energy efficiency? What are your views of utilizing a deferral mechanism but requiring that accumulated costs be amortized over several years, if deferrals were large?

Southwest Gas supports a revenue per customer decoupling mechanism that compares and adjusts for differences between authorized revenue per customer to actual, non-weather adjusted, revenues per customer. Such a mechanism would defer differences between authorized revenue and actual, non-weather adjusted, revenues on a monthly or annual basis.

As previously mentioned, decoupling adjustments tend to be small. Based upon the data contained in the revenue decoupling report prepared by Southwest Gas following its last general rate case, the average monthly bill impact from 2003-2008 would have been $0.13, or less than a penny a day. Furthermore, according to a recent report prepared by Pamela G. Lesh entitled *Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling, A Comprehensive Review*, a majority of the monthly adjustments from decoupling mechanisms for natural gas utilities were less than 1 percent. It is not anticipated that deferrals would ever exceed the potential $0.15 per therm variation that Southwest Gas customers could experience with gas costs recovered through its fuel adjustment provision. However, similar to considering exemptions of customer classes, Southwest Gas believes flexibility by the Commission and the utilities is important so that longer amortization periods can be considered on a case-by-case basis if facts and circumstances warrant their consideration.

[3] American Gas Association, *Natural Gas Rate Round-Up, A periodic Update on Innovative Rate Designs* (2007).

a. If the Commission was to adopt decoupling and use a deferral mechanism, how should usage related to new customer additions be treated during the deferral period, i.e. should it be excluded or included?

Included. All variations in use per customer, whether associated with new customers or previously existing customers, impact Southwest Gas' ability to recover its fixed costs. Southwest Gas supports a revenue per customer decoupling mechanism that compares and adjusts for differences between authorized revenue per customer to actual, non-weather adjusted, revenues per customer. Such a mechanism defers differences between authorized revenue and actual, non-weather adjusted, revenues on a monthly or annual basis. Consequently, the revenue per customer decoupling mechanism accounts for changes in the number of customers on Southwest Gas' system (both positive and negative), thus enhancing the matching principle as discussed in more detail below.

b. Should both programmatic and non-programmatic energy savings be included in the deferrals? If so, how should non-programmatic energy savings be measured and verified?

Yes. Both programmatic and non-programmatic savings should be included in the deferral. As previously mentioned, without inclusion of both programmatic and non-programmatic savings, the decoupling mechanism would not make a utility completely indifferent to their level of sales. If a decoupling mechanism includes only programmatic savings, utilities will not be indifferent to their level of sales and will instead have a significant financial incentive to increase customers' energy use to increase profitability. More importantly, customers are not afforded the complete protection that revenue per customer decoupling offers. Revenue per customer decoupling (inclusive of programmatic and non-programmatic savings) benefits customers by offering protections against utilities collecting more revenue than what the Commission authorized. Inclusion of both programmatic and non-programmatic savings results in proper alignment of customer and utility interests by completely eliminating the relationship between sales and profits. Consequently, inclusion of programmatic and non-programmatic savings ensures the only way a utility can increase its profitability is by reducing expenses, not by increasing sales.

Inclusion of non-programmatic savings also simplifies the measurement and verification process by eliminating the need for complex administratively burdensome measurement and evaluation processes. Furthermore, exclusion of non-programmatic savings may have the unintended consequence of limiting the number of conservation and energy efficiency measures supported by utilities. For instance, as noted by Ms. Schwartz of Regulatory Assistance Project, exclusion of non-programmatic savings makes utilities potential adversaries instead of motivated partners in the venues where energy efficiency goals and activities are addressed, such as state and federal processes to improve building codes and appliance standards, customer contact and referrals, and consumer education or market transformation efforts.[4]

6. **What features can be adopted as part of a decoupling proposal that would prevent the Company from over-earning, and address concerns that decoupling proposals necessarily mean deviating from the "matching principle"?**

As previously explained, one of the biggest misconceptions regarding decoupling is that somehow decoupling will facilitate a utility to over earn. To the contrary, revenue per customer decoupling actually protects customers by eliminating the opportunity for utilities to over earn through increased sales. Coincidentally, this provides additional incentive to utilities to efficiently manage expenses, which will benefit customers because the reduction in expenses will be passed on to customers in a subsequent rate case.

Furthermore, implementation of revenue per customer decoupling actually enhances the matching principle. Decoupling actually ensures that cost and revenue per customer remain more closely matched between rate cases by truing up revenue per customer, on average, back to the Commission-approved cost and revenue levels established in the last general rate case.

a. **Should the Commission consider a "cap on earnings" as part of its approval of a decoupling plan?**

As mentioned above, revenue per customer decoupling actually protects customers by eliminating the opportunity for utilities to over earn through increased sales. Indeed, an inherent feature of decoupling is that it prevents utilities from ever over earning, absent some significant reduction in costs, which will ultimately be passed on to customers in a subsequent rate case. Accordingly, a "cap-on earnings" is really not needed, but if that provides additional comfort to the Commission or other interested parties, Southwest Gas would not be opposed to a cap on its return on equity to ensure the company never earns a return on equity greater than what the Commission-authorized in its last general rate case.

[4] *See* Attachment D, Lisa Schwartz, *The Role of Decoupling Where Energy Efficiency Is Required By Law* (September 2009).

b. **Should a lower Return on Equity be adopted when considering rate cases for decoupled Companies to recognize that such companies may incur less risk compared to non-decoupled companies?**

Yes, if the facts and circumstances warrant such a reduction. If the analysis was simply: "Do gas utilities have either decoupled or non-decoupled rate designs?", all else being equal, then all decoupled gas utilities should have a lower required return on common equity. Unfortunately, the analysis of assessing the relative risk of a gas utility to a proxy group of comparable gas utilities is not that simple, as decoupling is only one of many factors to be considered when determining the appropriate return on equity.

In assessing the relative risk of a decoupled utility to a proxy group of comparable utilities, an examination of the degree of total revenue stabilization of the proxy group is required. For instance, other revenue stabilization mechanisms, such as straight-fixed-variable rate design, declining block rates, weather normalization clauses, etc., can provide revenue stabilization to a utility. Moreover, rate design is only one of many risk factors, while the required return on common equity is a function of total risk (regulatory, financial and business risk) faced by a utility. For instance, a state or federal energy-efficiency mandate in conjunction with a utility's reliance upon volumetric sales to recover Commission-approved fixed costs imposes additional risk upon a utility that should be considered when determining the appropriate return on equity. Similarly, while decoupling may reduce risk to a utility by stabilizing revenues, it also protects customers from the utility ever recovering more revenue per customer than what was authorized by the Commission. This protection takes away a potential upside in excess revenue to the utility and the removal of this potential benefit should also be considered when determining the utility's return on equity.

Southwest Gas addressed this specific issue in several recent general rate cases. During those proceedings, Southwest Gas utilized a proxy group that consisted of gas utilities that had some form of revenue stabilization (revenue decoupling, straight fixed variable rate design, weather normalization). Accordingly, Southwest Gas concluded that any reduction to return on equity should be commensurate with the proxy group's level of revenue stabilization as compared to Southwest Gas' level of revenue stabilization. For instance, if Southwest Gas has the same level of revenue stabilization as the proxy group, all else being equal, no adjustment is warranted.

c. **Should the Commission require that Companies' decoupling mechanisms and deferrals be reviewed after some period of time, i.e., after three years of operation, unless the Company comes in for a rate case sooner?**

Yes. Southwest Gas believes three years is an appropriate time period.

7. **Please state whether the information provided in the Revenue Decoupling Data Report filed in compliance with Decision No.70665 supports or argues against revenue decoupling in the case of natural gas companies.**

The information provided in the report supports revenue decoupling. The report takes a snapshot from an historic perspective on what the bill impacts would have been during 2003-2008 if the Commission had implemented revenue per customer decoupling. The report clearly demonstrates that bill impacts from decoupling are small, even miniscule, as the report found that the average monthly bill impact would have been $0.13, or less than a penny a day. Furthermore, according to the recent comprehensive review of decoupling mechanisms by Pamela Lesh, a majority of the monthly adjustments from decoupling mechanisms for natural gas utilities were less than 1 percent. Both reports overwhelmingly support the conclusion that the potential bill impact from revenue decoupling is minimal, and is significantly less than the potential bill impact from fuel adjustment mechanisms.

8. **What disincentives to customer conservation may be caused by virtue of the adoption of decoupling or decoupling-like mechanisms?**

None. As previously noted, this is a misconception regarding decoupling. Revenue per customer decoupling does not establish "fixed rates" that make utility bills independent of actual consumption. Decoupling allows the Commission to retain the current volumetric pricing scheme (recovering fixed costs in variable rates) to ensure customers receive the price signals intended by the Commission, but use small, regular rate adjustments to ensure against over- or under-recovery of Commission-approved fixed costs. In addition, there are no additional costs being paid by customers that were not already approved by the Commission in the utilities last general rate case, utilities are only recovering the authorized margin per customer approved by the Commission – nothing more. In addition, as previously mentioned, the data contained in the Southwest Gas decoupling report illustrates that average monthly bill impacts during the reporting period would have been $0.13, or less than a penny a day. The savings experienced by customers during the same time period due to reduced consumption averaged $1.60 per month.[5] Accordingly, customers would have still experienced an average savings of $1.47 per month, inclusive of any potential decoupling impact.

[5] Assuming an average gas cost of $0.76738.

9. Are price signals to consumers skewed by decoupling, and if so, how?

No. As previously mentioned in response to question #8, revenue per customer decoupling does not establish "fixed rates" that make utility bills independent of actual consumption. Decoupling allows the Commission to retain the current volumetric pricing scheme (recovering fixed costs in variable rates) to ensure customers receive the price signals intended by the Commission, but use small, regular rate adjustments to ensure against over- or under-recovery of Commission-approved fixed costs. As documented in the Southwest Gas decoupling report, these potential adjustments are less than one penny a day and are significantly less than cost of gas and the savings experienced by customers who implement conservation and energy efficiency programs. Indeed, the implementation of decoupling does not skew price signals as the savings experienced by customers during the reporting period would have been on average $1.47 per month, inclusive of any potential decoupling impact.[6]

10. What type of revenue decoupling mechanism is appropriate for Arizona or does it vary by company and with different facts?

- a. **Revenue per Customer?**
- b. **Sales margin per Customer?**
- c. **Total margin revenue?**
- d. **Total class revenue?**
- e. **Usage per customer?**

Southwest Gas supports, and recommends the Commission implement, a revenue per customer decoupling mechanism that compares and adjusts for differences between Commission-authorized revenue per customer to actual, non-weather adjusted, revenues per customer. As mentioned in responses to previous questions, such a mechanism establishes a ceiling and a floor with respect to the revenue per customer collected by Southwest Gas. Such a mechanism offers protections to customers that currently do not exist under Arizona's regulatory structure – by ensuring that Southwest Gas will never collect more revenue per customer than what the Commission-authorized in its last general rate case.

With respect to the different types of decoupling mechanisms, revenue per customer, sales margin per customer, and usage per customer are all similar in nature. In order to calculate the deferral dollar amount, the difference in actual versus test year revenue, margin, or sales per customer are multiplied by the number of customers and the applicable true-up charge. These types of mechanisms recognize customer growth that occurs between rate cases. However, in an historical test year state, like Arizona, the total margin revenue and total class revenue methods may fail to properly compensate utilities for the cost attributed to

[6] *Id.*

new customers added in-between rate cases. Therefore, a decoupling mechanism that is linked to revenue, sales, or usage at the customer level is most appropriate as it better matches revenues and costs, actually enhancing the matching principle. Decoupling actually ensures that cost and revenue per customer remain more closely matched between rate cases by truing up revenue per customer, on average, back to the Commission-approved cost and revenue level established in the last general rate case.

11. Should the Commission impose penalties for failure to meet specific designated DSM goals?

No. Revenue decoupling removes the financial disincentive experienced by utilities reliance upon volumetric sales to recover Commission-approved fixed costs. To impose penalties through a decoupling mechanism undermines the benefit decoupling provides to customers and the Commission policies that are attempting to be effectuated. The issue of performance incentives for achieving greater results in energy efficiency or penalties for failing to achieve energy efficiency targets is a separate issue and should not be tied to the implementation of a revenue decoupling mechanism.

a. Should the opportunity to have periodic rate adjustments be tied to meeting specific energy efficiency requirements?

No. As previously noted, revenue decoupling removes the financial disincentive experienced by Southwest Gas due to its reliance upon volumetric sales to recover Commission-approved fixed costs. Revenue decoupling is not intended to create an incentive for utilities to promote energy-efficiency measures, but to remove the disincentive to do so. Furthermore, encumbering a decoupling mechanism with conditions simply undermines the benefit decoupling provides to customers and the Commission policies that are attempting to be effectuated with the removal of the financial disincentive attendant to implementing energy-efficiency measures. Rewards and penalties for achieving and not achieving specific energy-efficiency targets should be addressed separately and distinct from revenue decoupling.

12. What means should be employed to track conservation associated with specific DSM programs for purposes of evaluating the success of decoupling?

Southwest Gas recommends the use of engineering estimates to calculate expected DSM program savings and to track the success associated with specific DSM programs. The engineering studies and models that are used to cost-justify the programs provide a reasonable measure of achieved conservation.

13. What mechanisms are needed to assure data quality and accuracy of forecasting customers, usage and utility driven energy efficiency savings?

None. Southwest Gas supports the current regulatory process whereby Commission Staff and other interested parties are provided an opportunity to conduct exhaustive review of customer forecasts, customer usage assumptions, and other related items prior to the approval and implementation of new DSM programs.

14. Should decoupling mechanisms include a low-income component?

A special low-income component of decoupling is unnecessary; low-income customers should be afforded the same benefits of decoupling as other customer classifications. As previously noted, revenue decoupling benefits customers by ensuring that utilities never collect more revenue than what the Commission authorizes. Accordingly, low-income customers should also have access to this benefit and protection of revenue decoupling.

a. Should utility energy-efficiency programs be structured to align costs and benefits among rate classifications?

No. Southwest Gas supports current Commission practice of providing a uniform recovery rate applicable to every customer class that has access to the programs. Southwest Gas believes this is reasonable as the programs are considered to provide societal benefits and advantages to all customers, equally.

15. What additional issues should the Commission consider when addressing utility disincentives to implementing its Energy Efficiency requirements?

As previously mentioned, removal of the financial disincentive is only one-third of the necessary business model for successfully implementing conservation and energy-efficiency programs.

The necessary business model includes: (1) timely cost recovery of the conservation and energy-efficiency program costs; (2) removal of the financial disincentive by eliminating the relationship between sales and fixed cost recovery, resulting in the alignment of customer and utility interests (i.e. revenue decoupling); and (3) performance incentives providing utilities an earnings opportunity so they become neutral in their preference to acquire supply- and demand-side resources. Similar to how utilities have an earnings opportunity with respect to plant they place into service, utilities should have an earnings opportunity on the investments they make in energy efficiency. Accordingly, Southwest Gas encourages the Commission to consider different options for timely cost recovery (for example creating a regulatory asset and amortizing the balance) and providing financial incentives for achieving certain energy-efficiency targets and goals to maximum performance by Arizona utilities.

In addition, with the implementation of revenue decoupling for all Arizona utilities, Southwest Gas encourages the Commission to begin considering the creation of an environment where electric and natural gas companies work together on conservation and energy-efficiency initiatives, and are encouraged to use their respective energy services in a manner where each product is most economically efficient, including the creation of a single interface with customers for all conservation and energy efficiency needs.

GRACEFUL SYSTEMS LLC

RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC UTILITY DECOUPLING

A COMPREHENSIVE REVIEW

Pamela G. Lesh

6/30/2009

This report catalogues all of the decoupling mechanisms in place for electric or gas utilities as of Spring 2009, and discusses several older, now expired, mechanisms as well. Where the information was obtainable, it includes the rate adjustments made under the decoupling mechanisms and expresses those as a percentage of rates. It also reviews major features of the mechanisms studied.

RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC UTILITY DECOUPLING: A COMPREHENSIVE REVIEW

Prepared by Pamela G. Lesh
June 2009

This report compiles the rate impact experience during this decade with decoupling of retail gas and electric utility revenues from sales volumes and provides, along with this, information on relevant order numbers, statutes, mechanism descriptions, and implementing tariffs. Sources included utility and state regulatory commission websites, the American Gas Association and the Edison Electric Institute, and, in a few cases, helpful utilities. Immediately below is a brief explanation of "decoupling" as used in this report, followed by a summary of the findings and a short description of methodology. The report concludes with observations about utility ratemaking.

Decoupling

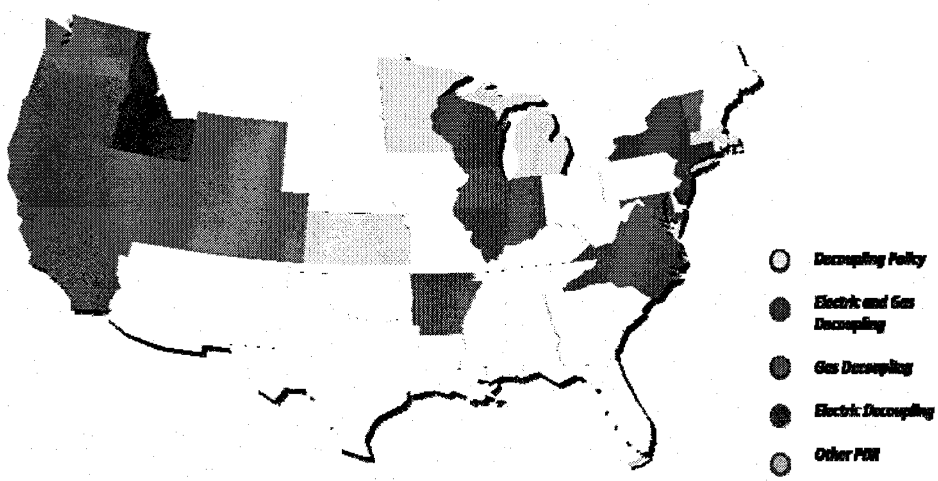
Decoupling is a regulatory term indicating that, through any one of several means, a given energy utility does not derive the portion of its revenues necessary to provide it an opportunity to recover its fixed costs of service on the basis of its sales of natural gas or electricity. Fixed costs of service include such things as the capital recovery cost of installed plant and equipment (depreciation, debt interest, and equity return), most operations and maintenance expenses and taxes. The largest cost that is not fixed is typically the cost of fuel or purchased power.

One primary means of decoupling, albeit with many variations, is through a regulatory adjustment mechanism that adjusts rates periodically to ensure that a utility records as revenue for fixed cost recovery no more and no less than the amount of revenue authorized for that cost coverage. This means of accomplishing decoupling does not affect how customers pay for energy utility services, enabling utilities to maintain volumetric rates and the incentive for customers to conserve or use energy more efficiently. In general, current rate designs include some amount of fixed customer charge per month and a per unit charge based on either gas or electricity consumption, or demand, or both. Although the utility continues to receive revenues from customers on this basis under a decoupling mechanism, it books only the revenue to cover fixed costs that its regulator has authorized, typically in a rate case or through the operation of a formula for calculating a change in fixed costs over time. For example, some such formulas change revenues authorized for fixed cost recovery according to the change in the number of customer accounts (often called revenue per customer); others change revenues for fixed cost recovery according to an inflation index, decreased for an assumed amount of productivity improvement (often called an attrition adjustment). On some regular basis, the decoupling mechanism provides a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were less or greater than the revenues the regulator authorized. This difference can occur for many reasons, primary among which are weather, economic conditions, and customer behavior that differ from assumptions in the ratemaking process.

It is also possible to break the link between fixed cost recovery and electricity or natural gas consumption by changing how customers pay for energy utility services. In general, this is called "straight fixed-variable" rate design, in which the fixed monthly customer charge recovers all of the utility's fixed costs of service and the variable, energy-related charge, covers only the variable cost of energy. Some Commissions adopting this type of rate design have called it 'decoupling." While this rate design does break the link between sales and fixed cost recovery, it does so by greatly diminishing customer incentives to conserve or invest in energy efficiency. Moreover, the change in rate design from a more traditional form can significantly shift costs within and between classes of customers. In particular, those customers with lower than average consumption can experience much higher bills as costs shift from variable, usage-based, charges to fixed, billing period, charges. This decoupling report excludes examples of this rate design because it does not result in adjustments to rates as the regulatory mechanism method does.

Review Summary

A total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, have operative decoupling mechanisms.[1] Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place. The map below shows the states covered by this report:

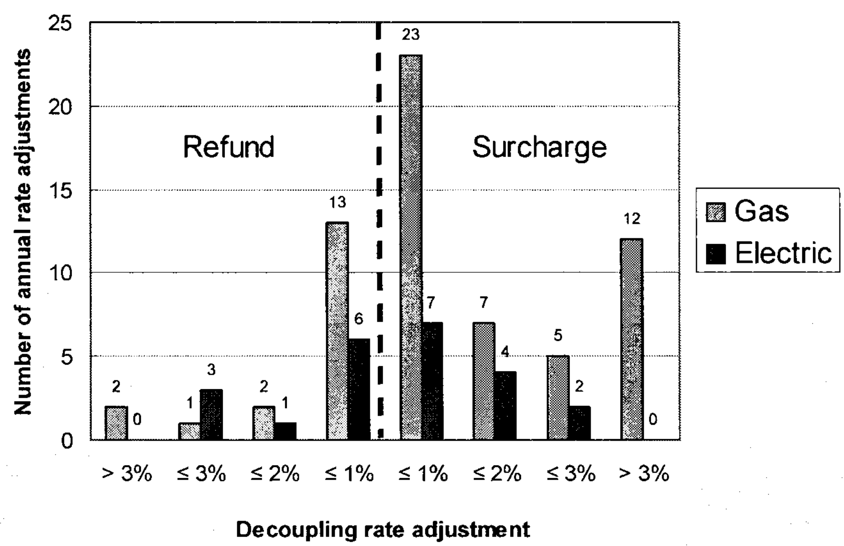


[1] This report includes two other current electric regulatory mechanisms that operate to some extent to decouple utility revenues from sales but do not permit calculation of decoupling adjustments. It also includes information on a few now-expired decoupling mechanisms, to the extent such information was discoverable.

Many of the mechanisms that exist began operation only within the last few years, although the California utilities have had some form of decoupling for much longer. Based on the available data, this review supports two definitive conclusions:

- Decoupling adjustments tend to be small, even miniscule. Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under two percent, positive or negative, with the majority under 1 percent.[2] Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month in higher or lower charges for residential electric customers.
- Decoupling adjustments go both ways, providing both refunds and surcharges to customers. This is particularly true for those mechanisms that operate on a monthly basis, but also is true for those adjusted annually or semi-annually. There are many reasons, of course, that actual revenues can deviate from the revenues assumed in ratemaking. Most of the mechanisms do not adjust revenues for the effects of weather, leaving that as the primary cause of greater and lower sales volumes, particularly for residential rate schedules. Other causes include energy efficiency, programmatic and otherwise, customer conservation, price elasticity, and economic conditions. Regardless of the particular combination of causes for any given adjustment, no pattern of either rate increases or decreases emerges.

The figure below summarizes the distribution of decoupling adjustments in place since 2000.



---
[2] These are not actual rate changes, simply a comparison of the decoupling adjustment to the total rate at or near the time of the adjustment. See methodology summary for an explanation of why it is impossible to determine actual decoupling rate changes that customers may have experienced. Counts in the figure include only the annual average of those mechanisms that have monthly adjustments.

By comparison, rate adjustments under purchased gas cost adjustment or fuel/purchased power cost adjustment clauses tend to be much larger. Although a review of actual adjustments under these clauses was beyond the scope of this study, the following history for one electric (Idaho Power Company) and one gas utility (Northwest Natural Gas Company), both of which had decoupling mechanisms for part of the period, provides an example for context:

		Northwest Natural		Idaho Power	
Year		PGA % Change	Decoupling % Change[3]	PCA % Change (Res)	Decoupling % Change
1995		(6.2)			
1996		(4.8)			
1997		10.5			
1998		9.2			
1999		7.2			
2000		21.4			
2001		20.8			
2002		(12.7)		7.5	
2003		4.9	0.6	(18.9)	
2004		20.1	0.36	0	
2005		16.6	0.77	0	
2006		3.8	(0.27)	(14.0)	
2007		(8.7)	(0.1)	11.0	
2008		15.6	<(1.0)	8.45	(0.8)
2009				10.2	0.8

The information gathered below supports several other observations about decoupling:

- The mechanisms have a great variety of names, almost none of which contain the word "decoupling." Names ranged from "Billing Determinant Adjustment" to "Volume Balancing Adjustment" to "Bill Stabilization Rider" and more.
- Most mechanisms appear in a separate tariff page, although in one or two cases the mechanism is combined with an energy efficiency program tariff and the California utilities do not have a tariff for decoupling. Instead, the California utilities have regulatory authority to make the calculations and rate adjustments as part of an "Annual True-up" procedure.
- Almost all of the gas utilities with decoupling mechanisms also adjust rates to account for the effects of weather on revenues. For some, this occurs logically under the decoupling mechanism, which performs calculations based on actual, not weather-adjusted, revenues. For others, eliminating the effects of weather on the revenues the utility collects to cover fixed costs occurs under a separate tariff. Under either approach, the utilities no longer face a risk of under-recovering fixed costs or reaping a windfall if weather is different from that

[3] For Northwest Natural, the decoupling adjustment is included in the overall PGA; thus, these are not additive.

assumed in the ratemaking process. In contrast, a couple of electric utilities calculate decoupling adjustments on the basis of weather-adjusted revenues. For these, the utility keeps revenues associated with sales caused by weather more extreme, and forgoes revenues lost because of weather milder, than that assumed for ratemaking purposes.

- Most of the mechanisms produce an annual adjustment, but a handful of utilities adjust rates monthly and one or two semi-annually. The monthly adjustments tend to be very small but can go up and down six times in as many months. The tables below show only the annual average of monthly adjustments and, in a few cases, high and low adjustments during the year.
- Most mechanisms perform the calculation of the difference between actual fixed cost revenues and authorized fixed costs revenues on a per customer class or per rate schedule basis, refunding or surcharging the result only to that schedule or class.
- A number of these decoupling mechanisms are in place only on a "pilot" basis, subject to cancellation or further regulatory process after 3-4 years.
- Most of the mechanisms allow utilities to keep additional revenues from growth in the number of customer accounts during a decoupling period. This can occur either by expressing the fixed costs as a revenue-per-customer amount and reconciling actual revenues to the revenue per customer amount times the current number of customers, or by adjusting the allowed revenue requirement for customer growth and reconciling actual revenues to that adjusted amount. A few utilities receive an explicit attrition adjustment, approved by the Commission and not dependent on the number of customers.
- Some of the 28 mechanisms include some unusual features. For three utilities, adjustments only occur if they are surcharges; the mechanism does not require refunds. Another two utilities can collect surcharges only if savings in gas costs offset the lost margin. Some mechanisms limit the dollar amount or percentage of rate change permitted, either deferring any excess for later recovery/credit or simply eliminating it.

The table below summarizes some of the different features of decoupling mechanisms, indicating how many of the mechanisms have each type of feature.

Feature	Gas Decoupling	Electric Decoupling
Revenue change between rate cases		
Revenue-per-customer[1]	23	4
Attrition adjustment[2]	3	4
No change	3	1
No separate tariff	3	3
Timing of Rate True-ups		
Annual	19	8
Semi-annual/quarterly	2	1
Monthly	4	3
Weather[3]		

Not weather-adjusted	20	10
Weather-adjusted	8	2
Limit on adjustments and/or dead-band[4]	9	6
Per class calculation and adjustments[5]	25	7
Earnings Test[6]	4	
Pilot/known expiration date	11	4
Surcharges only	3	
Total Utilities Analyzed	**28**	**12**

Notes to table

1. "Revenue per customer" means that the decoupling mechanism calculates the authorized revenue to which the utility will reconcile its actual revenues by dividing the last approved fixed cost revenue requirement by the number of customer accounts assumed in that ratemaking process, and then multiplying the per-customer amount by the number of customers in the current decoupling period. For example, if the authorized fixed cost revenue requirement was $1 billion and the ratemaking number of accounts was 1 million, the fixed cost per customer amount would be $1000/year. If, during a given decoupling year, the actual number of customer accounts was 1,050,000, the utility would refund any amount by which its actual revenues exceeded $1.05 billion. Thus, the additional customer accounts contribute $50 million to fixed cost recovery.
2. "Revenue requirement true-up" means that the decoupling mechanism simply compares the actual foxed cost revenues to the amount authorized for fixed cost recovery in the utility's last rate case, even if that was several years prior. Thus, the utility may face declining income as inflation and other factors increase fixed costs. The sub-category of these that are "with attrition" indicate the utilities for whom that authorized revenue requirement changes from year to year according some formula, generally an inflation index less an assumed amount of productivity improvement. This may be part of the decoupling mechanism, done as a means of calculating the comparator for the actual revenues collected, or external to the decoupling mechanism and causing its own rate adjustment.
3. "Weather" refers to revenue variances attributable to actual weather differing from the weather conditions assumed in the ratemaking process. If a decoupling mechanism uses actual revenues that are not weather-adjusted, that means that revenue variances attributable to weather will affect the size of the customer refund or surcharge.
4. "Limit on adjustments or a dead-band" refers to features in a given decoupling mechanism that limit the size of any (or a cumulative set of) customer refund or surcharge, or in the case of a dead-band, exclude a certain amount of the variance (again, refund or surcharge) before calculating the positive or negative decoupling rate increment. For most of the mechanisms that have a limit on the size of decoupling adjustments, any amount not refunded or surcharged carries over to the next decoupling period. That is not always the case, however.
5. "Per class calculation and spread of adjustments" means that the mechanism determines the difference between the authorized fixed cost revenue and the actual revenue on a per class or per rate schedule basis and refunds or surcharges

the resulting amount only to that rate schedule or customer class. Included in the count are utilities for which the decoupling mechanism applies only to one customer class or rate schedule. Only eight utilities have mechanisms that do not do this.

6. "Earnings test" refers to a limitation on decoupling surcharges by which the utility may not recover revenue differences calculated by the mechanism to the extent that recovery would increase its earnings over a specified return on common equity, whether the last authorized or another amount.

The next several years will significantly increase experience with decoupling, both for those utilities for whom decoupling is of relatively long-standing and for those that have just begun their implementation. It would be worthwhile to update this review at some point to determine whether these conclusions hold true with additional experience, particularly among the electric utilities for whom data is presently scarcer than for gas utilities.

Methodology

Generally, it was possible to find a tariff stating the decoupling adjustment, either in cents or dollars per therm, or cents per kWh. This was not the case only for the California utilities, whose decoupling does not occur under a separate tariff but as part of a much larger annual filing. Those utilities very helpfully provided the information needed for this report. Amounts in ( ) are rebates to customers; other amounts are surcharges. In general, amounts are rounded to two to three digits.

It was much more difficult to find a total retail rate for the rate classes covered by the decoupling mechanism and, thus, to calculate the size of the decoupling adjustment as a percentage of the total rate. This was particularly problematic where the adjustments were for prior years or the commodity portion of the rate changed frequently, as is common for gas utilities and restructured electric utilities. In many cases, this report uses average annual (or monthly for 2009) retail gas and electric price information for the appropriate state found on the EIA website. The goal was to provide context for the decoupling adjustment, not state precise percentages and the EIA data served well for the purpose.

For a couple of reasons, it is impossible to determine from the sources available what changes in rates actually occurred when. First and foremost, whether a given decoupling adjustment caused a rate increase or decrease depends on what was in rates before for decoupling. For example, if a decoupling adjustment produced a refund one year and a somewhat smaller refund the second year, the rate change customers would experience would be a small increase, as the prior credit expired and was not fully replaced by the current credit. The reverse can also happen: the expiration of a decoupling surcharge will produce a rate decrease unless the subsequent decoupling adjustment is the same or a larger surcharge. Second, many utilities combine one or more rate changes at one time. Changes in commodity costs or balancing accounts or other tariff riders along with the decoupling adjustment are common and could easily offset or mask the decoupling adjustment. For two utilities, such offsetting was the deliberate design.

STATE/UTILITY INFORMATION

Arkansas

Arkansas Oklahoma (gas)
Case/Order No.: 07-026-U, Order No. 7 (11/20/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment
http://www.apscservices.info/tariffs/112_gas_1.PDF
The tariff expires August 31, 2011; the utility must re-file to continue decoupling.
Energy efficiency cost recovery: incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and true-up procedure filed by April, for June adjustments.
History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

Arkansas Western (gas)
Case/Order No.: 06-124-U, Order No. 6 (7/13/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 3.6
http://www.apscservices.info/tariffs/145_gas_1.PDF
The tariff expires July 31, 2010; the utility must re-file to continue decoupling.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-078-TF); forecast and true-up procedure; April filings for January 1 adjustment.
History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

CenterPoint Energy Resources (gas)
Case/Order No.: 06-161-U; Order No. 6 (10/25/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 6
http://www.apscservices.info/tariffs/64_gas_2.PDF

Tariff expires on December 31, 2010; the utility must re-file to continue.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-081-TF); forecast and true-up procedure; April filings for January adjustment.
History of Adjustments: The first filing under the tariff was March 31, 2009. CenterPoint made no adjustment because sales slightly exceeded revenue requirement sales.

California

California first adopted decoupling, through the Supply Adjustment Mechanism (SAM), for gas utilities in 1978 in Decision 88835. By 1982, similar mechanisms were in place for the three electric IOUs. The ratemaking construct worked by establishing a revenue requirement for each utility annually and then reconciling actual revenues to the allowed revenues. Information on the electric decoupling adjustments during this first period is available for most years from 1983 through 1993 through an analysis done by Lawrence Berkeley Labs in 1994.[4] The authors compared the rate adjustments that took place with those that would have occurred without the decoupling amounts. The following were the decoupling-only rate adjustments identified:

Year	PG&E (% of total rates)	SCE (% of total rates)	SDG&E[5] (% of total rates)
1983	2.3	Not available	1.2
1984	(3.4)	(0.5)	1.0
1985	(4.8)	(2.1)	(6.8)
1986	1.9	2.1	1.8
1987	2.1	(1.0)	11.0
1988	5.0	(1.5)	(12.0)
1989	(4.3)	2.4	0.7
1990	(5.4)	(2.1)	4.8
1991	3.9	3.5	(1.8)
1992	3.4	(0.6)	1.4
1993	0.0	(1.9)	Not available

As the gas industry restructured, gas utilities began to serve large (non-core) customers under a straight fixed-variable rate design, which continues through today. For core customers (commonly residential and smaller commercial), decoupling continued.

The CPUC largely stopped the electric decoupling mechanisms in 1996, with the advent of electric restructuring. It is unclear whether the last reconciliation adjustment was 1995

[4] The Theory and Practice of Decoupling, Joeseph Eto et al., Lawrence Berkeley Laboratory, January 1994 Website: http://eetd.lbl.gov/EA/emp/reports/34555.pdf
[5] The article providing these historical decoupling adjustments does not explain the outlying double-digit increase and decrease for SDG&E. Given that the two are in consecutive years, one might surmise that a load forecasting or mathematical error caused the decoupling increase in the one year only to correct it and reverse the amount in the following year.

or 1996. In 2001, however, the Legislature passed Public Utilities Code section 739.10, which required that the CPUC resume decoupling.

739.10. The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collections of the electrical corporations.

In individual rate cases following this, the CPUC approved resumption of electric.[6]

Pacific Gas and Electric (electric)
Case/Order Nos.: A.02-11-017 et al.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm
The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years. PG&E has three specific accounts that combine to accomplish decoupling: the Distribution Revenue Adjustment Mechanism, the Nuclear Decommissioning Revenue Adjustment Mechanism, and the Utility Generation Balancing Account.
Decoupling tariff: No specific tariff.
Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.
Energy efficiency cost recovery: Yes
History of Adjustments

Year of Adjustment[7]	Revenue Rqmt ($ millions)	Decoupling Adjustment ($ millions)	Decoupling as % of Total Revenue[8]
2005	9,715	99.41	1.0
2006	9,875	24.64	0.25
2007	10,371	148.9	1.4
2008	10,609	11.4	0.11
2009	11.169	103.55	0.9

Pacific Gas and Electric (gas)
Case/Order Nos.: A.02-11-017 et al.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm
The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No specific tariff; adjustment occurs in Annual True-Up filing
Filing Schedule: Filings occur in December for January 1 effective dates
Energy efficiency cost recovery: Yes

[6] Some amount of decoupling, for some of the utilities, may have occurred between adoption of restructuring and the adoption of section 739.10. It is unclear.
[7] The adjustment is collected in the year following the year that the revenue variance occurred.
[8] Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

History of Adjustments

Year of Adjustment	Revenue Rqmt ($ millions)	Decoupling Adjustment ($ millions)	Decoupling as a % of Delivery Revenue[9]
2006	982.8	37.95	3.9
2007	1,026	46.77	4.6
2008	1,095	11.26	1
2009	1,091	50.86	4.7

Southern California Edison (electric)
Case/Order Nos.: A.93-120-29; Decision 02-04-055. The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No specific tariff.
Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.
Energy efficiency cost recovery: Yes
History of Adjustments

Year	**Annual Change in Rates for Decoupling[10] (%)**
2004	(2.1)
2005	(2.1)
2006	0.1
2007	(1.0)
2008	2.2

San Diego Gas & Electric (electric)
Case/Order No.: Case/Order No.: A.02-12-027
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No separate tariff

[9] The percentages would be much smaller with commodity reflected in the total as well. Because PG&E could not provide the per-therm adjustment related to decoupling, it was not possible to calculate the decoupling as a percentage of the total rate to customers, even using EIA data.

[10] Rate changes reflect the difference between the rate change without the base revenue requirement balancing account (BRRBA) and the rate change with the BRRBA. Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations.
Energy efficiency cost recovery: Yes
History of Adjustments[11]

Year	Rate (¢/kWh)	Decoupling Rate Change (¢/kWh)	Decoupling change compared to Rate (%)
2005	13.773	(0.055)	(0.40)
2006	13.935	(0.210)	(1.5)
2007	13.997	(0.051)	(0.36)
2008	13.606	(0.044	0.32
2009	16.726	0.128	0.76

SoCal Gas/SDG&E (gas)
Case/Order No.: A.02-12-027; D.05-03-023
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No separate tariff
Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations
Energy efficiency cost recovery: Yes
History of Adjustments[12]

Year/ Core/Non-Core	Rate (¢/therm)	Decoupling Rate Change (¢/therm)	Decoupling Change compared to Rate (%)
2006			
Core	48.348	0.012	0.02
Non-Core	5.36	0	0
2007			
Core	50.196	0.024	0.05
Non-Core	4.852	(0.001)	(0.01)
2008			
Core	51.526	0.001	0
Non-Core	3.576	(0.001)	(0.04)
2009			
Core	55.052	0.003	0.01
Non-Core	2.954	0.002	0.07

[11] The numbers are estimates only and reflect the best efforts of SDG&E to isolate the decoupling elements. Contact Lisa Davidson at 858-636-3928 for information or updates.
[12] The numbers below are estimates only and reflect the company's best efforts to isolate the decoupling elements. Rates shown are for delivery services only.

Southwest Gas Corporation (gas)
Case/Order No.: A.02-02-012, Order 04-03-034
http://docs.cpuc.ca.gov/Published/Final_decision/35920.htm
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: Core Fixed Cost Adjustment Mechanism (line item in cost of gas)
http://www.swgas.com/tariffs/catariff/rates/historic/2009/06-07-2009/rates-nocal.pdf and
http://www.swgas.com/tariffs/catariff/cover/ca_gas_tariff.pdf (see Sheet 6739-G)
Filing Schedule: Changes occur every January 1
Energy efficiency cost recovery: Yes
History of Adjustments

Year	Average Commercial Rate[13] ($/therm)	Northern Territory Decoupling Adj ($/therm)	% of Retail Rate (est[14])	Southern Territory Decoupling Adj ($/therm)	% of Retail Rate[15]
2005	1.07	0.004	0.4	0.05	4.7
2006	1.04	0	0	0.05	4.8
2007	1.02	(0.0006)	<(.01)	0.004	0.4
2008	1.17	(0.016)	(1.4)	0.010	0.9
2009	0.94	(0.051)	(5)	0.013	1.4

Colorado

Colorado has adopted decoupling only for one utility – gas – and then only for a three-year experiment. Recent legislation authorizes the Commission to ensure cost recovery for both electric and natural gas energy efficiency programs but does not address decoupling. See §40-3.2-103 and 104.

Public Service of Colorado (gas)
Case/Order No.: 06S-656G; Order No. C07-0568
http://www.dora.state.co.us/puc/DocketsDecisions/HighprofileDockets/06S-656G.htm

[13] Source: EIA data, annual through 2008 and January 2009. For simplicity, this assumes translates MCF into therms without the small additional amount of btu associated with a therm.
[14] This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.
[15] This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.

Type of decoupling: Reconciliation of residential use-per-customer times ratemaking margin to actual, weather-normalized use-per-customer times ratemaking margin; utility allowed to recover only differences greater than or equal to 1.3% decline in use per customer (cumulates every year of mechanism); increases in use-per-customer accrue to offset losses in use-per-customer in prior or future years.
Decoupling Tariff: Partial Decoupling Rate Adjustment, Sheet 51
http://www.xcelenergy.com/SiteCollectionDocuments/docs/psco_gas_entire_tariff.pdf
The tariff expires October 1, 2011; the utility must re-file to continue decoupling. Filing Schedule: Adjusts every year on October 1
Energy efficiency cost recovery: Cost recovery reconciled to actual costs; semi-annual filing for July 1 and January 1 rate changes
History of adjustments

September 2008 filing for margin differences July 2007 through June 2008: $0

Connecticut

2007 Connecticut legislation requires that the Commission adopt decoupling mechanisms for the states' electric and natural gas utilities. CT Public Act No. 07-242
http://www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm

United Illuminating (electric)
Case/Order No.: 08-07-04 (February 2009 and June 2009)
http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f4217b3542e2b08b852575530075d08c?OpenDocument and
http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/3b76f3e31c22cb19852575cb005cea73?OpenDocument
Type of decoupling: Reconciliation of actual, non-weather adjusted revenues to ratemaking revenues. Refunds or surcharges allocated to all classes based on revenue.
Decoupling Tariff: United Illuminating has not yet filed a tariff to implement the Commission's approval of its decoupling mechanism because it was awaiting the results of a request for reconsideration. A tariff will likely be filed shortly. Extension beyond 2010 requires specific Commission approval.
Filing Schedule: Within 14 months after new rates effective
Energy efficiency cost recovery: Yes
History of Adjustments

There will not be any adjustments under this order for approximately 14 months.

Idaho

Idaho Power Company (electric)
Case/Order No.: IPC-E-04-15; Order No. 30267
http://www.puc.idaho.gov/search/search.htm (Search under order number).
Type of decoupling: For residential and small commercial customers, the mechanism reconciles actual number of customers to ratemaking number of customers times a set fixed cost per customer and weather-adjusted sales per customer to ratemaking sales per customer for a set fixed cost per kWh amount. Adjustments are capped at 3% over the

previous year, with carry-over to subsequent years. Although the mechanism specifies calculating and refunding/charging any adjustment on a per class basis, the Commission departed from this in the first two adjustments because of concern regarding the lack of current cost of service studies to support the underlying cost allocations. This is a three-year pilot program, expiring May 31, 2010.
Decoupling tariff: Schedule 54
http://www.puc.state.id.us/tariff/approved/Electric/Idaho%20Power%20Company.pdf
Filing Schedule: Adjustments occur each June 1 (filed March 15), with adjustments based on results from the prior calendar year.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and reconciliation procedure filed by April for June adjustments.
History of Adjustments

Year	**Residential Decoupling ($ million)**	**Adjustment[16] (¢/kWh)**	**Rate change (%)**	**Small Commercial Decoupling ($ million)**	**Adjustment (¢/kWh)**	**Rate change (%)**
2008	(3.6)	(0.0457)	(0.71)[17]	1.2	(0.0457)	(0.71)
2009[18]	1.3	0.0529	0.82	1.4	0.0529	0.82

Kansas

In 2008, the Commission issued an order addressing generally cost recovery and incentives associated with utility energy efficiency programs. Docket No. 08-GIMX-441-GIV (November 14, 2008) http://www.kcc.state.ks.us/scan/200811/20081114142730.pdf. The Commission endorsed the concept of using a tariff rider to recover program costs on a timely basis, with pre-filing of programs and budgets to provide utilities assurance of concurrence in their plans. In the order, the Commission also determined that decoupling was the best method of addressing the throughput incentive that utilities otherwise face, rejecting both a straight fixed-variable rate design and lost revenue recovery as reasonable alternatives. It invited utilities to file decoupling proposals in connection with their energy efficiency programs.

Illinois

North Shore Gas (gas)

[16] The Commission ordered that the decoupling adjustments be summed and the result designed into an even adjustment across the two customer classes. This was, in part, because Idaho Power lacked a recent cost of service study suitable to allocate fixed costs between the two classes.
[17] This is an estimate using the 2009 retail rate implied by the filing of the 2009 adjustment and the 2008 adjustment.
[18] Filed March 15, but not yet approved.

Case/Order No.: 07-0241/07-0242 (Cons)
http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per-class basis.
Decoupling tariff: Volume Balancing Adjustment (VBA), sheets 60-64
http://www.northshoregasdelivery.com/news/tariffs/vba.pdf
This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.
Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.
Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.
History of adjustments[19]

North Shore Gas Service Classification	True-up: rate case to actual margin ($)	True-up: percentage of margin (%)	True-up: percentage of total revenues (%)[20]
Residential Sales	(547,804.42)	(3.3)	(0.46)
Residential Transportation	(5,101.34)	(1.3)	(0.1)
Comm/Ind Sales	(89,053.00)	(3)	(0.33)
Comm/Ind Transportation	(327,781.95)	(0.5)	(0.5)

Peoples Gas and Coke (gas)
Case/Order No.: 07-0241/07-0242 (Cons)
http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per class basis.
Decoupling tariff: Volume Balancing Adjustment (VBA), Sheets 61-65
http://www.peoplesgasdelivery.com/news/tariffs/vba.pdf
This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.
Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.
Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.
History of adjustments[21]

[19] Prepared from the annual reconciliation filing.
[20] Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, $8.48/Mcf.
[21] Prepared from the annual reconciliation filing.

Peoples Gas Service Classification	True-up: rate case to actual margin ($)	True-up: percentage of margin (%)	True-up: percentage of total revenues (est.)[22] (%)
Residential Sales	(2,035,714.64)	(2)	(0.43)
Residential Transportation	(53,882.01)	(2.4)	(0.15)
Comm/Ind Sales	(431,457.89)	(1)	(0.19)
Comm/Ind Transportation	(2,217,245.22)	(6.9)	(0.73)

Indiana

Vectren Indiana Gas (gas)
Case/Order No.: 42943 (December 2006)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38
https://www.vectrenenergy.com/cms/assets/pdfs/indiana_gas_tariff.pdf
Energy efficiency cost recovery: Yes, in the same tariff
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (210)	0.017	6.4	1.5
General (220/225)	0.0034	2.0	0.3
2009			
Residential (210)	0.00364	1.4	0.4
General (220/225)	(0.00762)	4.4	(0.86)

Vectren Southern Indiana Gas (gas)

[22] Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, $8.48/Mcf.

Case/Order No.: 42943 (December 2006)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38
https://www.vectrenenergy.com/cms/assets/pdfs/south_services_gas_tariff.pdf
Energy efficiency cost recovery: Yes, in the same tariff
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (110)	0.0085	4.7	0.8
General (120/125)	0.0035	2.9	0.3
2009			
Residential (110)	0.00152	0.8	0.2
General (120/125)	(0.00469)	(4)	(0.6)

Citizen's Gas & Coke (gas)
Case/Order No.: 42767 (April 2007)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800dd673
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Rider E, page 505
http://www.citizensgas.com/pdf/NGRatesRidersTC/RiderE.pdf
Energy efficiency cost recovery: Yes, through Rider E
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Res Non-Heat	0.002	0.45	0.16
Res Heat	(0.0002)	(0.067)	(0.02)
General Non-Heat	(0.0006)	(0.5)	(0.006)
General Heat	0	0	0

2009			
Res Non-Heat	0.0133	3	1.2
Res Heat	0.0223	7.3	2.2
General Non-Heat	0.0157	12.86	1.9
General Heat	0.0212	12.9	2.4

Maryland

Maryland has both gas and electric decoupling in place; the former began in the early 2000s, and the latter just within the last few years. All of the mechanisms make monthly adjustments. The amounts below are averages of the monthly adjustments for the periods shown. For several of the utilities, the largest and smallest adjustments within a given year are also shown.

Baltimore Gas & Electric (electric)
Case/Order No.: [Unable to locate]
Type of Decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods.
Decoupling Tariff: Monthly Rate Adjustment, Rider 25
http://www.bge.com/portal/site/bge/menuitem.b0ab2663e7ca6787047eb471016176a0/
Filing Schedule: Monthly
Energy efficiency cost recovery: Yes
History of Adjustments

Period	Res. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate[23]	Small Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate	Gen'l Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate
2008[24]						
Largest Adj	0.445		0.215		0.2303	
Smallest Adj	(0.066)		(0.215)		0.1456	
Average Adj	0.136	1.1	0.025	0.22	0.21	2.1
2009						
Largest Adj	0.237		0.119		0.23	
Smallest Adj	(0.237)		(0.215)		(0.215)	
Average Adj	(0.069)	(0.5)	(0.048)	(0.4)	(0.043)	(0.4)

Delmarva (electric)

[23] EIA data on Maryland retail rates for the respective years used as a proxy to determine percentages.
[24] The mechanism was effective January 2008, with the first adjustment occurring in March 2008 based on January variances. The filing for the November 2008 adjustment was missing from the Maryland Commission website.

Case/Order No.: Case Jacket 9093; Order 81518, July 2007
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling Tariff: Bill Stabilization Adjustment Rider, Leaf 102
http://www.delmarva.com/home/choice/md/tariffs/
Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, Leaf 132
History of adjustments

Period/Rate	Average Decoupling Adjustment[25] (¢/kWh)	Estimated Total Rate[26] (¢/kWh)	Decoupling as % of Rate[27]
11/07 – 10/08			
Residential	0.16	11.09	1.4
General	0.21	11.80	1.8
11/08 – 4/09			
Residential	0.16	10.69	1.5
General	0.29	11.40	2.5

PEPCO (electric)
Case/Order No.: Case Jacket 9092, Order 81517, July 2007
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling tariff: Bill Stabilization Adjustment Rider, page 47
http://www.pepco.com/_res/documents/md_tariff.pdf
Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, page 48
History of Adjustments

[25] PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For the partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.
[26] For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland.
[27] The percentage shown is only as of total rate for residential and general service. The percentage is of delivery costs only for large industrial; with added commodity, the percentage change would be much lower.

Period/Rate	Average Decoupling Adjustment[28] (¢/kWh)	Estimated Total Rate[29] (¢/kWh)	Decoupling as % of Rate
11/07 – 10/08			
Residential	0.06	10.75	0.56
General	0.08	12.74	0.63
Large	0.013	8.14	0.16
11/08 – 2/09			
Residential	0.25	10.75	2.3
General	0.14	12.74	1.1
Large	0.02	8.14	0.25

Baltimore Gas & Electric (gas)
Case/Order No.: Case 9036; Order 80460
http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9000-9099\9036\Item_116\&CaseN=9036\Item_116
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling tariff: Monthly Rate Adjustment, Rider 8
http://www.bge.com/portal/site/bge/menuitem.d7305449a99570c7047eb471016176a0/
Energy efficiency cost recovery: Yes. Gas Efficiency Charge, Rider 1
History of Adjustments

Period	Residential Decoupling Adjustment ($/therm)	Decoupling Adjustment % of Retail Rate[30]	Commercial Decoupling Adjustment ($/therm)	Decoupling Adjustment % of Retail Rate
2006[31]				
Largest Adj	0.05		0.05	
Smallest Adj	(0.01)		(0.05)	
Average Adj	0.0316	1.9	(0.005)	(0.4)
2007[32]				

[28] PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For he partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.
[29] For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland. It is not clear if the standard offer rate is with or without distribution charges built in. This analysis assumes these are included. If they are not, the decoupling adjustment as a percentage of the total rate would be even lower.
[30] EIA data for the respective years used as a proxy for the retail rate.
[31] The first decoupling adjustment appears to have occurred in July 2006. The filing for the 09/06 adjustment was missing from the Maryland Commission website.

Largest Adj	0.0397		0.0159	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0323)	(2.1)	(0.043)	(3.5)
2008[33]				
Largest Adj	0.073		0.05	
Smallest Adj	(0.05)		(0.05)	
Average Adj	0.02	1.2	(0.0223)	(1.7)
2009				
Largest Adj	0.008		0.0212	
Smallest Adj	(0.0272)		(0.05)	
Average Adj	(0.014)	<(0.1)	(0.01)	(0.8)

Washington Gas Light (gas)

Case/Order No.: Case 8990; Order No. 80130
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500

Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 5¢, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.

Decoupling tariff: Revenue Normalization Adjustment, General Service Provisions No. 30 http://www.washgas.com/FileUpload/File/Tariffs/MD/md9899.pdf

Energy efficiency cost recovery: Yes. Demand-side Management Surcharge Adjustment, General Service Provisions No. 22

History of Adjustments:

Period	Residential Decoupling $/therm	Decoupling Adjustment % of Retail[34]	Commercial Decoupling $/therm	Decoupling Adjustment % of Retail
December 2005	0.0258	1.7	0.0139	1.2
2006				
Largest Adj	0.05		0.045	
Smallest Adj	0.0146		(0.05)	
Average Adj	0.0415	2.5	(0.02)	(1.5)
2007				
Largest Adj	0.0323		0.0499	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0085)	(0.56)	(0.027)	(2.2)
2008				
Largest Adj	0.05		0.05	
Smallest Adj	(0.05)		(0.05)	

[32] Filings for adjustments for January, March and April were missing from the Maryland Commission website.
[33] Filings for adjustments in April, October and November were mission from the Maryland Commission website.
[34] Retail prices based on EIA data for Maryland for respective years.

Average Adj 2009[35]	(0.0013)	(0.08)	(0.005)	(0.39)
Largest Adj	0.0344		0.0245	
Smallest Adj	(0.05)		(0.0386)	
Average Adj	(0.018)	(1.5)	(0.022)	(2.0)

Massachusetts

Massachusetts has announced a regulatory policy in favor of decoupling for all of its gas and electric utilities. D.P.U 07-50-A (July 2008) http://www.mass.gov/Eoeea/docs/dpu/electric/07-50/71608dpuord.pdf. None of the utilities have mechanisms in place yet.

Minnesota

In 2007, the Minnesota legislature enacted Section 216B.2412, https://www.revisor.leg.state.mn.us/statutes/?id=216B.2412 in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission to "establish criteria and standards" by which it could adopt decoupling for the state's rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the PUC will have established. To date, no utility pilots are in place.

Michigan

In 2008, Michigan passed PA 295, http://legislature.mi.gov/doc.aspx?2007-SB-0213 a comprehensive bill adopting a renewable energy portfolio standard and an energy efficiency portfolio standard for state electric and natural gas utilities. Section 89(6) states that the commission shall authorize any natural gas utility that spends a minimum of 0.5% of total natural gas retail sales revenues, including natural gas commodity costs, in a year on commission-approved energy efficiency programs to implement a symmetrical revenue decoupling true-up mechanism that adjusts for sales volumes that are above or below the projected levels that were used to determine the authorized revenue requirement. The Commission has not yet approved a decoupling mechanism under this section.

Nevada

In 2008, the Nevada Public Service Commission adopted temporary rules allowing gas utilities to propose a decoupling mechanism in a general rate case filed within one year of the approval of a set of energy efficiency programs for that utility. Docket No. 07-06046. http://pucweb1.state.nv.us/wx/DocView.aspx?DataSource=PUCN+Imaging&ParamEnc=

[35] Through May 2009.

28%3a4D605690F11E27F012E1E60C8921FD1EEDD79CFEA0229DFE8B7EB14452AF2C471C7CEAA1CF970B67CDA2AD4AE0CDFC51ED5922B5E6DD1B98989E303FB8F15D5D6D08D6153BAE4347AB1F5BA1161334F5CABA7968A9E94DA44ABC5B285CF46983F6774787FD62A42DC2948DCD8AA319003AF71485E3D7CE47887E97027141DC1825216D42A37388884DCB825AF30A075ADD824901B04B3682834A110EC55B357C08408C4D4732131396D0FDA84963BDD583915C2B541AC56C896E054A5B867D68DE185F5C7EA0D65E1F97F262BB32E527A71B4540EC51FFAA201E818A3E9D5315 The rules specify revenue per customer mechanism design, with adjustments done on a per class basis. NAC (Nevada Administrative Code) 704.953. http://pucweb1.state.nv.us/PUCN/general/pucnac.aspx

New Jersey

South Jersey Gas Company (gas)

Case/Order No.: Order No. GR05121019 (October 2006) (Link not available)

Type of decoupling: Reconciles ratemaking margin revenue per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency related to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but amounts excluded carry over.

Decoupling tariff: Conservation Incentive Program, Rider M, Sheet 97c http://www.southjerseygas.com/108/tariff/Tariff060109.pdf

Energy efficiency cost recovery: Yes. Rider K, Clean Energy Program Clause (CLEP) Note that this includes lost revenue associated with programmatic savings.

History of Adjustments[36]

Class/Year	Decoupling Adjustment[37] ($/therm)	Decoupling amount as % of margin[38]	Decoupling amount as % of rate[39]
2008			
Residential	0.0443	9.8	2.8
General	0.0392	10.9	2.6
General Large Volume	(0.0037)	(1.3)	(0.3)
2009			
Residential	0.0707	15.6	4.8
General	0.0684	19	5
General Large Volume	0.0062	2.1	0.5

[36] The mechanism began in October 2006, with the first adjustment in October 2007.

[37] South Jersey does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.

[38] Margin based on currently published tariffs.

[39] This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively. These amounts are not rate changes per se. In particular, the 2009 decoupling adjustments as a percentage of the total rate is shown without regard to the prior 2008 rate change. On a cumulative basis, the increase was only approximately 1.6% for residential customers.

New Jersey Natural Gas Company (gas)
Case/Order No.: Order No. GR05121020 (October 2006) (link not available)
Type of decoupling: Reconciles ratemaking margin revenues per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency attributable to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but any recovery so excluded carries over.
Decoupling tariff: Conservation Incentive Program, Rider I
http://www.njng.com/regulatory/pdf/060109.pdf
Energy efficiency cost recovery: Yes. Rider E, Clean Energy Program Clause (CLEP)

History of Adjustments[40]

Class/Year	Decoupling Adjustment[41] ($/therm)	Decoupling amount as % of rate[42]
2008		
Residential	0.0261	1.7
General	0.0248	2.0
2009		
Residential	0.0378	2.5
General	0.0424	2.8

New York

Consolidated Edison (gas)
Case/Order No.: 06-G-1332; 1-102-06G1332 (September 2007)
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=06-G-1332&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather-adjusted revenues per customer with ratemaking revenues per customer, according to several service classification groupings.
Decoupling tariff: General Information Special Adjustment No. 14, leaf 181-182; apparently in force only 10/07 through 9/08
http://www.coned.com/documents/gas_tariff/pdf/0003(09)-General_Information.pdf#page=12
Energy efficiency cost recovery: Yes
History of Adjustments (Unable to locate)

[40] The mechanism began in October 2006, with the first adjustment in October 2007.
[41] New Jersey Natural Gas does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.
[42] This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively. These amounts are not rate changes per se. 2008 EIA commercial retail gas price data for New Jersey was not available; this uses the 2007 annual.

Consolidated Edison (electric)
Case/Order No.: 07-E-0523; 1-301-07E0523 (March 25, 2008)[43]
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0523&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather adjusted revenues to ratemaking revenues on a per class basis. Adjusts semi-annually.
Decoupling tariff: PSC No. 9-Electricity, Leaf 168F
http://www.coned.com/documents/elec/165-168i.pdf
Energy efficiency cost recovery: Pending; decoupling specifically adopted without connection to an approved energy efficiency program
History of Adjustments[44]

Service Class	Adjustment	Percent of Delivery Charge[45]
Residential (1)	(0.1502)	(2.3)
General Commercial (2)	(0.0071)	(0.8)

National Fuel Gas Distribution (gas)
Case/Order No.: 07-G-0141, 1-102-07G0141 (December 2007)
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-G-0141&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, weather-normalized margin revenue per customer with ratemaking margin per customer, adjusted for net customers added. There is a separate weather adjustment that applies for October through May only.
Decoupling tariff: Conservation Incentive Program Cost Recovery, Sheet 148.9; adjustments effective on annual basis, December through November
https://www2.dps.state.ny.us/ETS/jobs/display/download/4677590.pdf
Energy efficiency cost recovery: Yes
History of Adjustments

Service Class	Adjustment $/Mcf	Percent of Rates[46]
Residential	(0.082)	(0.77)
General Service	(0.082)	(0.87)

[43] The order included a 10 basis point ROE reduction ordered to account for the effect of the decoupling mechanism on the utility's risk.
[44] The decoupling mechanism applies to 10 schedules in total. Many of those contain demand charges that make calculation of the per kWh decupling adjustment as a percentage of the rate difficult. The two shown above contain by far the greatest number of customers.
[45] This charge does not include electricity commodity. The decoupling adjustments as a percentage of that amount would be even smaller.
[46] Based on May 2009 retail rates. These rates change monthly.

Orange & Rockland (electric)
Case/Order No.: 07-E-0949; Order No. 1-302-07E0949
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0949&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather adjusted revenues with ratemaking revenues (delivery only) per class with certain schedules excluded: economic development, lighting, special contracts. Ratemaking revenues adjust automatically according to a three-year schedule. Program ends June 30, 2011.
Decoupling tariff: General Information Sheet 25
http://www.oru.com/documents/tariffsandregulatorydocuments/ny/electrictariff/electricGI25.pdf ;
Energy efficiency cost recovery: Programs and recovery pending in separate proceeding 07-M-0548 to be decided later in 2008.
History of Adjustments: None to date.

North Carolina

In 2007, North Carolina enacted a statute specifically authorizing the Commission to approve decoupling mechanisms for natural gas utilities.
http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.7.html

Piedmont Natural Gas (gas)
Case/Order No.: Dockets G-9, Sub 499 (November 2005) and G-9, Sub 550 (November 2008) http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA52350B&parm3=000123283 and http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=SAAAAA89280B&parm3=000128268
Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.
Decoupling tariff: Customer Utilization Tracker (CUT), now called Margin Decoupling Tracker, Appendix C
http://www.piedmontng.com/rates/tariffs/uploadedTariffs/ncTariff.pdf
Energy efficiency cost recovery: In the initial 3-year decoupling experiment, the utility donated funds totaling $750,000 for energy efficiency without recovery; in the extension, the Commission approved including $1.275 million in rates for these programs
Energy efficiency incentives: No.
History of Adjustments

Period	Residential Adjustment $/therm	% of Rate[47]	Small Comm. Adjustment $/therm	% of Rate	Med. Comm. Adjustment $/therm	% of Rate
Apr 2006	0.02262	1.3	0.0123	0.87	0.000860	<0.1
Nov 2006	0.05181	3.1	0.02339	1.7	0.011389	1.0
Apr 2007	0.07791	5.0	0.04127	3.2	0.00996	1.0
Nov 2007	0.06153	3.9	0.03118	2.4	0.01213	1.2
Apr 2008	0.08471	5.1	0.04732	3.3	0.01452	1.2
Nov 2008	0.07494	4.5	0.03819	2.7	0.02394	1.9

Public Service Company of North Carolina (gas)
Case/Order No.: G-5, Sub 495 (October 2008) http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=RAAAAA89280B&parm3=000128260
Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.
Decoupling tariff: Rider C Customer Usage Tracker
http://www.psncenergy.com/NR/rdonlyres/0E0B99DA-911C-4674-AF7E-EA5602091DB6/0/Rider_C.pdf
Energy efficiency cost recovery: Yes, up to $750,000 per year, with no true-up to actual expenditures
History of Adjustments
The Commission just approved the decoupling mechanism for PS Co of North Carolina in October 2008. The first adjustment under the mechanism has not occurred as of May 2009, but will likely appear shortly.

Oregon

Cascade Natural Gas (gas)
Case/Order No.: UG 167; Order No. 06-191
http://apps.puc.state.or.us/orders/2006ords/06-191.pdf
Type of decoupling: Reconciles actual margin per customer with ratemaking margin per customer, adjusted for current customer count but does so separately for weather-related variances and all other variances. Calculations and rate adjustments done on a per rate schedule basis. Earnings sharing applies to extent earnings with adjustment clauses recoveries exceed 175 basis points over allowed return on common equity. Decoupling ends after three years unless the utility re-files.
Decoupling tariff: Rule 19, Original Sheet 30, Conservation Alliance Plan mechanism
http://www.cngc.com/post/rates_tariffs/oregon/0030_Rule_19_-_Conservation_Alliance_Plan.pdf

[47] EIA annual city gate prices for respective years used as a proxy for total rate. It is useful to remember these are not necessarily rate changes in customer bills. Assuming nothing else was occurring, slight rate increases would have occurred in April and November 2006 and April 2007, but then a decrease in November 2007 as the decoupling adjustment declined from the prior level, an increase in April 2008 and an decrease again in November 2008.

Energy efficiency cost recovery: Yes, through a public purpose charge the revenue from which goes to the Energy Trust of Oregon for programs
History of Adjustments

	Decoupling Use-Per-Customer Forecast Change ($/therm)	Decoupling True-Up ($/therm)	Average Total Rate ($/therm)	Total Decoupling as % of Rate
7/06 – 6/07				
Residential	0.01693	0.01538	1.26	2.6
Commercial	0.00934	0.01538	1.12	2.2
7/07 – 6/08				
Residential	(0.0292)	(0.02055)	1.39	(3.6)
Commercial	(0.0112)	(0.02055)	1.25	(2.5)

Northwest Natural Gas (gas)
Case/Order No.: UG 163, Order No. 07-426
http://apps.puc.state.or.us/orders/2007ords/07-426.pdf
Type of decoupling: Reconciles actual, weather-adjusted margin per customer with ratemaking margin per customer, adjusted for current customer count, by customer class. Weather-adjustment occurs through a separate tariff from which customers can choose to opt out. Program runs through October 2012.
Decoupling tariff: Schedule 190
https://www.nwnatural.com/CMS300/uploadedFiles/24190ai(3).pdf
Energy efficiency cost recovery: Through a public purpose charge – the revenues collected go to the Energy Trust of Oregon to run programs.
History of Adjustments

Year	Decoupling Adjustment ($ million)	Decoupling Adjustment (% of rate)
2003	3.6	0.6
2004	2.1	0.36
2005	6.2	0.77
2006	(2.2)	(0.27)
2007	0.8	<0.1
2008	(2.5)	<(1.0)

PacifiCorp (electric)
Case/Order No.: UE-94; Order No. 98-191 (not available electronically)
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=5178
Type of decoupling: Reconciled actual weather-adjusted revenues to ratemaking revenues for distribution services only. Ratemaking revenues increased each year, automatically, by inflation less a 0.3% productivity factor. The mechanism was part of a 3-year

alternate-form-of-regulation (AFOR). The AFOR expired shortly before Oregon restructuring (February 2002).
Decoupling tariff: NA
Energy efficiency cost recovery: Yes, through a public purpose charge included in the package.
History of Adjustments[48]

Customer Class	1999	2000	2001
Residential	(0.39)	1.9	1.85
Small General Service	(0.6)	(0.22)	0.06
General Service	(0.83)	(0.31)	0.09
Large General Service	0.61	0.33	(0.3)
Irrigation	0.45	0.25	(0.2)

Portland General Electric (electric)
Case/Order No.: UE-197; Order No. 09-020 and 09-196
http://apps.puc.state.or.us/orders/2009ords/09-176.pdf
Type of decoupling: Reconciles actual, weather-adjusted fixed cost revenue per customer for residential and small general service to ratemaking fixed cost revenue per customer, by customer class. Decoupling adjustments limited to two percent per year, positive or negative; amounts in excess do not roll over to future periods.[49] Program runs two years.
Decoupling tariff: Schedule 123
http://www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/Sched_123.pdf
Energy efficiency cost recovery: Yes, through a regular and an add-on public purpose charge; virtually all of the funding goes to the Energy Trust of Oregon to run programs.
History of Adjustments: None yet. The first should occur in 2010.

Utah

Questar Gas (gas)
Case/Order No.: 05-057-T01 (October 2006)
http://www.psc.utah.gov/utilities/gas/06orders/Oct/05057t01oass.pdf
Type of decoupling: Reconciles actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for the general service class. Accruals to the balancing account per year capped at a cumulative 1% of gross revenues per twelve-month period. Three-year program ends December 2009. Renewal dockets are pending.
Decoupling tariff: 2.08 Conservation Enabling Tariff
http://www.questargas.com/Tariffs/uttariff.pdf
Energy efficiency cost recovery: Yes, 2.09 Demand-side Management tariff
History of Adjustments

[48] The figures shown are actual rate changes (in %) attributable to decoupling within the overall alternate form of regulation.
[49] Commission order approving decoupling applied a 10 basis point return on common equity reduction.

Period	Decoupling Adjustment (% of overall rate)
7/06 – 3/07	0.27
4/07 – 8/07	0.36
9/07 – 3/08	(0.47)
4/08 – 8/08	0.01

Vermont

Central Vermont Public Service (electric)
Case/Order No.: 7336, http://www.state.vt.us/psb/orders/2008/files/7336%20Final.pdf
Type of decoupling: CVPS has an alternative regulatory plan under which it may adjust rates every year based on forecast costs and sales. This limits any benefit of increased sales during a given year to a partial year, at best. In addition, there is an adjustment mechanism for earnings that fall outside of a dead-band of 75 basis points around the allowed return on common equity. Outside of the dead-band, any excess or shortfall is first shared between the utility and customers and, beyond a certain amount, passed through in full to customers. If consumption reductions have caused revenues to fall, this mechanism may trigger a partial collection of the shortfall from customers. It will be difficult to calculate to what extent revenue changes driven by consumption changes have contributed to any adjustment, however.
Decoupling tariff: NA
Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider
History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Green Mountain Power (electric)
Case/Order No.: 7175 and 7176 http://www.state.vt.us/psb/orders/2006/files/7175-7176finalorder.pdf
Type of decoupling: As with Central Vermont Public Service (CVPS), the partial decoupling occurs through a comprehensive alternative form of regulation. Under the 3-year plan, GMP changes its rates every year based on a forecast of sales and costs. Thus, sales increases provide, at most, a partial year benefit to the Company. In addition, the earnings sharing provision operates, as CVPS' does, to minimize the loss if sales should fall significantly from forecast as well as share the benefit with customers if sales should rise. The Board explicitly found that full decoupling was unnecessary with this comprehensive plan.
Decoupling tariff: NA
Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider
History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Virginia

Virginia Gas (gas)
Case/Order No.: PUE-2008-00060 (December 2008)
http://docket.scc.virginia.gov/vaprod/main.asp
Type of decoupling: For residential customers only, reconciles actual, weather-adjusted revenue per customer to ratemaking revenue per customer approved in an existing performance-based ratemaking plan. A separate weather adjustment rider exists.
Decoupling tariff: Revenue Normalization Adjustment Rider D (not available in utility's on-line tariff)
Energy efficiency cost recovery: Yes
History of Adjustments: None to date.

Washington

Cascade Natural Gas (gas)
Case/Order No.: UG-060256 (January 2007), Order Nos. 05, 06, and 07
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/c6d08ccab87aceb2882572610082a4df!OpenDocument ,
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/2293364b330b249c8825733900798c2c!OpenDocument,
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/67316d49ff5b839e882573670080db42!OpenDocument
Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for residential and general commercial service only, by rate schedule. Adjustments occur the annual Temporary Technical Adjustment filing.
Decoupling tariff: Original Sheet 25, Conservation Alliance Plan mechanism
http://www.cngc.com/post/rates_tariffs/washington/021_Rule_Conservation_Alliance_Plan_Mechanism.pdf
Energy efficiency cost recovery: Yes
History of Adjustments: The mechanism took effect October 2007 and the first adjustment period ran through December 2008. Cascade reported an adjustment of ($401,328.82) in March 2009. The minor rate decrease associated with this will occur along with Cascade's PGA filing in Fall 2009.

Avista (gas)
Case/Order No.: UG-060518 (February 2007)
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/f1f6a64cb9d2aa0688257275007a230d!OpenDocument
Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for general service customers only, with a positive or negative adjustment of 90% of the difference. Recoveries limited to amounts that bring the utility up to its allowed return on common equity and contingent upon meeting certain energy efficiency targets, using a sliding scale. Any surcharges resulting

from the decoupling calculation limited to two percent per year, cumulative over the program (6%). Three-year pilot program.
Decoupling tariff: Schedule 159 (applies only to General Service)
http://www.avistautilities.com/services/energypricing/tariffs/wa/gas/Documents/WA_159.pdf
Energy efficiency cost recovery: Yes, schedule 191
History of Adjustments

Period	Adjustment Effective in Rates ¢/therm	Percentage of Margin	Percentage of Total Rate[50]
1/07 – 6/07	.257	1.25	0.28
7/07 – 12/07	.257	1.18	0.25
1/08 – 6/08	.593	2.73	0.58
7/08 – 12/08	.593	2.73	0.56

Wisconsin

Wisconsin Public Service Corporation (electric and gas)
Case/Order No.: Docket No. 6690-UR-119
http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=106184 and
http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=108565
Type of Decoupling: For both gas and electric, reconciles actual, non-weather-adjusted margin revenues per customer, by customer class, with ratemaking margin revenues per customer, adjusted for actual number of customers. Margin determined several different ways, depending on customer class and whether distribution fixed costs or supply fixed cost. Caps apply – amounts in excess of the cap not booked for later credit or surcharge; caps based on revenue requirement value of 100 basis points of return on common equity ($8 for gas; $14 for electric). Four-year pilot program.
Decoupling Tariffs: PSCW-8, Schedule GRSM-1 (gas)
http://www.wisconsinpublicservice.com/news/gas/GRSM.pdf: PSCW-7, Schedule ERSM-1 (electric) http://www.wisconsinpublicservice.com/news/electric/ERSM.pdf ling
Weather: Revenues not weather adjusted – actual revenues used
Energy efficiency cost recovery: Yes
History of Adjustments: None to date.

Wyoming

Questar Gas Company (gas)
Case/Order No.: 30010-94-GR-8 (May 2009)[51] (order not yet available electronically)

[50] Estimated using 2007, 2008 and January 2009 City Gate gas prices for Washington from EIA. These are not actual rate changes; rather just the adjustment expressed as a percentage of the entire rate. During the period of Avista's decoupling adjustment so far, there have been only two rate changes.
[51] The order is not yet available on the Commission's website.

Type of decoupling: Reportedly similar to Utah mechanism, which reconciles actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for one class of customer.
Decoupling tariff: (tariff not yet available electronically)
Energy efficiency cost recovery: Yes

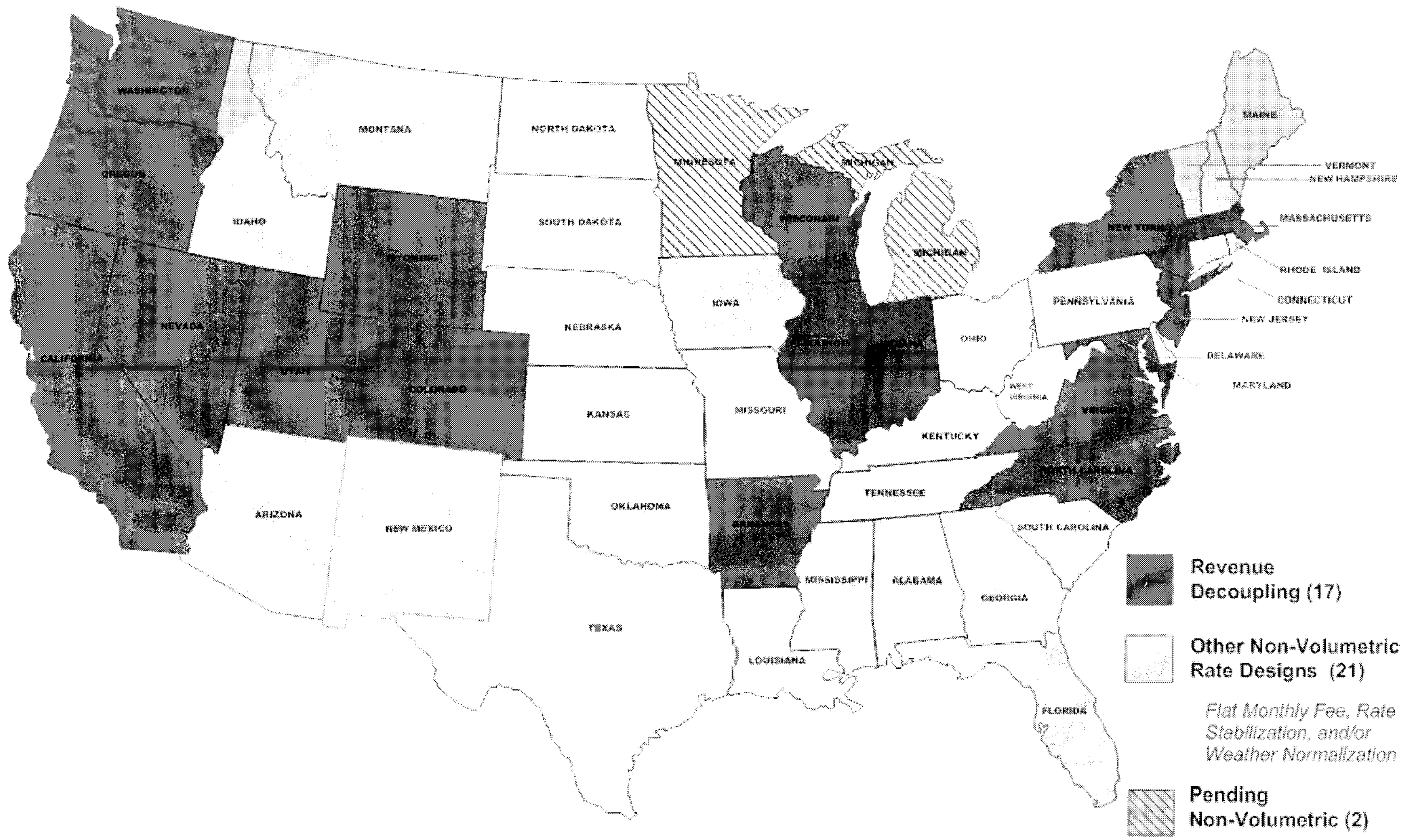
Closing Observation

Finding all of the decoupling mechanisms and summarizing the adjustments made under them was an exceedingly difficult task. I have a total of over 25 years in utility matters, most spent in the regulatory affairs department of a mid-sized electric utility. I know my way around a tariff and am generally familiar with naming conventions and so forth used by public utility commissions. Despite this wealth of experience, the task was difficult. This caused me to wonder what those not on the "inside" can possibly think of how utilities and regulators present information? Most would not think that the obfuscation was deliberate but many would conclude that ensuring people actually understood utility rates and regulation was not the goal.

The means of tackling this issue range from the simple to the significant. As a simple matter, some conventions around what utilities and commissions call things, what information appears in filing letters and annual (perhaps) information compiling tariffs and riders into complete rate information would help. This would seem a useful place for NARUC to work, in collaboration with the AGA and EEI. A far more significant effort would be the re-thinking of the tariff structure used by virtually every utility in the country. I suspect that most have changed little, in structure, for well over 50 years. General conditions appear in one place, riders and adjustments clauses in another, "base" rates somewhere else in schedule numbers that mean nothing to anyone. Tariffs may now be "on" the Internet, but they are not Internet-enabled or Internet-friendly. It seems likely that the future holds more variation in, and personalization of, rates, not less. Again, the utilities and regulators should collaborate to envision the "tariffs" (if we still call them that) of the future and how the industry might go about the transformation.

STATES WITH NON-VOLUMETRIC RATE DESIGNS FOR NATURAL GAS

AS OF JANUARY 2010



AGA American Gas Association

Regulatory Assistance Project
Issuesletter

September 2009

THE ROLE OF DECOUPLING WHERE ENERGY EFFICIENCY IS REQUIRED BY LAW

The American Council for an Energy-Efficient Economy (ACEEE) reports that 19 US states have adopted an Energy Efficiency Resource Standard (EERS) requiring achievement of specified energy saving targets.[1] *A comprehensive energy bill pending in the 111th Congress includes a combined efficiency and renewable electricity standard that would allow electricity savings to meet at least one-quarter of the requirement.*[2] *A more targeted proposal calls for a federal EERS that would require distribution utilities to achieve electricity savings of 15 percent and natural gas savings of 10 percent by 2020* (see table).[3]

Principal author
Lisa Schwartz

Such standards, or broader requirements to acquire all cost-effective energy efficiency, raise the question of whether decoupling of utility profits from utility sales still has a role in meeting state and federal goals for efficiency and other clean energy sources. This *Issuesletter* explains why aggressive standards make it even more urgent that state Commissions reject structural conflict in traditional regulation that frustrates the least-cost, least-risk path to a low-carbon future. Without decoupling – that is, under traditional ratemaking – utilities are told to do one thing (promote energy efficiency) while they typically make more money when they do the opposite (increase sales).

Proposed Federal EERS [5]

Sector	Electricity		Natural Gas	
Year	Annual Savings	Cumulative Savings	Annual Savings	Cumulative Savings
2011	0.33%	0.33%	0.25%	0.25%
2012	0.67%	1.00%	0.50%	0.75%
2013	1.00%	2.00%	0.75%	1.50%
2014	1.25%	3.25%	1.00%	2.50%
2015	1.25%	4.50%	1.00%	3.50%
2016	1.50%	6.00%	1.25%	4.75%
2017	1.50%	7.50%	1.25%	6.00%
2018	2.50%	10.00%	1.25%	7.25%
2019	2.50%	12.50%	1.25%	8.50%
2020	2.50%	15.00%	1.50%	10.00%

Energy Efficiency Resource Standards

An EERS is similar in concept to a renewable energy standard. It requires the state or utility to achieve specified levels of energy savings. Savings targets typically are expressed as a percentage reduction relative to retail energy sales during a baseline period – for example, average sales during a prior two-year period.[4] These savings are generally achieved through efficiency programs for end-use customers. Savings from building codes, appliance efficiency standards, combined heat and power facilities, and distribution system efficiency improvements also may count toward meeting the standard.

If the jurisdiction adopts a cumulative savings objective – say, 15 percent electricity savings by 2020 – annual targets will typically increase over time to reflect the continued impacts of measures installed each year. With a cumulative target, the lifetime savings associated with installation of energy efficiency measures are counted. Thus program administrators are fully credited for installing long-lived and well-maintained measures. Yearly savings targets provide short-term goals and a yardstick for monitoring progress.

An EERS is a performance-based approach that, once established, removes the need to continually address funding levels for energy efficiency - at least for a while. An EERS may allow an alternative compliance payment in lieu of meeting the standard, with the money directed to a state agency charged with achieving the intended savings. A penalty may be assessed for falling short of the requirements. Where the obligation falls on the utility, the law may allow the trading of savings with other utilities as well as contracting with energy service companies or a state agency to administer programs to meet the standard.

Many jurisdictions outside the US have implemented mechanisms similar to an EERS. The longest running of these is in the United Kingdom. Beginning in 1994, the Energy Efficiency Standards of Performance required electricity suppliers (retailers) to spend £1 per residential customer on household energy-saving measures and set energy savings targets to be achieved by the suppliers.[6] In 2000, the program was extended to all electricity and gas suppliers with at least 50,000 customers, becoming the dominant energy efficiency vehicle for residential customers in the UK. In 2002, the program was renamed the Energy Efficiency Commitment with a new focus on reducing greenhouse gas emissions. However, supplier targets were still expressed in terms of energy savings. Now known as the Carbon Emissions Reduction Target, it is the main policy instrument in the UK for reducing carbon emissions from existing homes. Under the program, electricity and gas suppliers must meet specified carbon emissions reductions.[7]

In Australia, New South Wales, Victoria, and South Australia have imposed what are in effect energy efficiency resource standards. These take the form of obligations imposed on electricity retailers, expressed as reductions in greenhouse gas emissions from electricity sold.[8] Specified energy efficiency measures in the residential sector are deemed to achieve set levels of emissions reduction. In New South Wales and Victoria, the emissions reduction obligation is linked to a trading scheme for energy efficiency certificates.[9]

Energy Efficiency Potential and Cost

ACEEE cites a median level of cost-effective, achievable potential for electric savings in the US of 18 percent.[10, 11] That means currently available technologies and approaches can reduce by 18 percent the amount of electricity needed to provide the same level of service. The potential for natural gas savings also is large. The American Gas Association reports that annual energy savings of member utility efficiency programs averaged nine percent of usage for residential participants and seven percent for all participants in 2007.[12] Similarly, ACEEE reports savings from Vermont Gas programs from 1999 to 2006 at 7.8 percent of 2006 sales, and Iowa gas utility programs from 1996 to 2006 at 8.2 percent of 2006 sales.[13]

Not only is there a vast potential remaining to be tapped, but energy efficiency also costs far less than supply-side alternatives. The National Action Plan for Energy Efficiency (NAPEE) cites "conservatively high estimates" for the total (utility and participant) cost of efficiency programs at 4 cents per kilowatt-hour (kWh) for electricity measures and $3 per million British thermal units (MMBtu) for natural gas measures.[14] ACEEE reports preliminary research results indicating average program costs of about 3 cents per kWh saved and 29 cents per therm saved ($2.90 per MMBtu).[15]

Compare that to the cost of a new natural gas-fired, combined-cycle combustion turbine. One recent forecast put the real-levelized cost at 8 cents per kWh (2006 dollars), including transmission.[16, 17] The same forecast projects natural gas prices for the period 2010 to 2029 at about $8 per MMBtu (2006 dollars).[18] These price estimates do not reflect distribution costs, reserves, line losses, or potential regulatory costs for greenhouse gas emissions.

Given the tremendous potential of energy efficiency, its cost compared to supply-side alternatives, and its zero-carbon footprint,[19] states should do all they can to remove regulatory barriers that stand in the way of accelerating its acquisition – with or without an EERS.

Decoupling Basics

Most utility costs do not change immediately in response to changes in energy consumption. In the short run, capital costs for generation, transmission, and distribution, as well as expenses for meter reading, billing, customer service, and administration, are largely fixed. However, like most businesses, utilities recover a large amount of their fixed costs through volumetric rates. Because so many of the costs of providing service do not change in the short run, a one percent change in sales can result in a disproportionately larger change in utility earnings, on the order of 10 percent or more.[20, 21] That's a powerful disincentive to embracing energy efficiency and, conversely, a very strong reason to increase sales.

Decoupling breaks the link between how much energy a utility sells and the revenue it collects to cover fixed costs.[22] Fundamentally, decoupling eliminates a utility's incentive to encourage consumers to increase energy use in order to increase profits as well as its disincentive to promote energy efficiency.

Decoupling is often viewed as a significant deviation from traditional regulatory practice. In fact, it is only a slight modification. The difference is straightforward.

In a rate case, the Commission sets the amount of revenue a utility ought to collect if it experiences the assumed financial, business, and sales conditions. The utility's "revenue requirement" is the sum of its expected expenses, return of – and return on – investment, and taxes, all during the test year used in the case. In theory, the amount collected should be sufficient to cover the utility's cost of service – no more, no less.

Under traditional regulation, the revenue requirement is used only to set prices (revenue requirement ÷ unit sales during the test period). Actual revenue and profit are a function of actual sales and expenses (actual profit = actual sales - actual expenses), which, in reality, have no relationship to the allowed revenue or rate of return in the rate case.

A utility can increase profits two ways under traditional regulation: (1) reduce expenses and (2) increase sales (units sold). It's easier to increase sales, which in turn increases revenue and profit. This is the heart of the throughput incentive, and it's where decoupling comes in.

Under decoupling, the rate case process remains the same. However, the prices computed in the case are in place for an initial period[23] and thereafter are relevant only as a reference point. Prices are adjusted periodically to keep revenue at its allowed level,[24] reflecting differences between the forecasted units sold (in the rate case) and actual units sold. In other words, decoupling fixes the revenue the utility collects and lets prices float up or down with actual sales. If sales increase, prices fall. If sales decrease, prices rise. That's in contrast to traditional regulation which fixes prices between rate cases and lets revenue float up or down with actual sales. A recent study found that decoupling price adjustments for electric and natural gas utilities tend to be small – typically under two percent of the total retail rate, positive or negative, with the majority under one percent.[25]

Decoupling often is considered when introducing or expanding energy efficiency efforts, but it also is desirable outside that context. That's because, under decoupling, the only way a utility can increase its profits is by reducing costs. A strong incentive to manage costs efficiently is especially welcome today, with ratepayers facing mounting pressure on near-term rates as utilities transition to low-carbon energy sources, advanced metering, and distribution and transmission system upgrades - all of which should ultimately reduce consumer bills.

Commissions also should consider adopting or strengthening service quality standards in tandem with decoupling, to ensure that service is maintained at current or improved levels. Such standards include metrics against which utility performance will be evaluated, financial penalties for failure to meet the standards, and public reporting requirements. Among the measures to consider are at-fault customer complaints, billing accuracy, power interruptions, safety violations, vegetative management, and inspections and maintenance.

EERS and Decoupling

Under traditional price-setting regulation, a utility with a legal mandate to acquire energy efficiency[26] feels the financial pinch of reduced sales just as it would without such an aggressive requirement, only more sharply. At the same time, the utility will still have the incentive to increase sales in order to increase profits.

That structural conflict is at best paradoxical. At worst, it makes utilities adversaries instead of motivated partners in the myriad of venues where energy efficiency goals and activities are hammered out, including:[27]

- State and federal processes to improve building codes and appliance standards
- Customer contacts and referrals
- Consumer education
- Customer-specific[28] and aggregate information for third-party program administrators and service providers

Furthermore, the same throughput incentive that deters utilities from making energy efficiency investments also dissuades them from supporting distributed generation and demand response, both of which also can decrease sales.

These conflicts play out within the utility, too. Personnel promoting customer-sited resource programs run up against financial staff stymieing their efforts. When visible, regulators are left to sort out the mixed signals - a frustrating experience in uncovering the facts. Such counteraction also sends confusing messages to consumers and the efficiency marketplace, potentially wasting efficiency funds and momentum.

The stress intensifies under an EERS, with annual savings requirements of, say, two percent of prior period sales. Such requirements do not correct the fundamental problem of a utility business model that is incompatible with reducing energy sales. A utility in this situation will simply have another perverse incentive - to work hard to make it look like the targets are reached, but not necessarily to achieve the actual savings required. That includes "gaming" sales forecasts - as well as savings estimates - in every proceeding that establishes base rates. Absent decoupling, utilities are motivated (only by fear of penalty) to do the bare minimum to meet the standards, regardless of the savings potential or benefits to consumers from exceeding the standards.

Does Third-Party Administration Solve the Problem?

Third-party administration of energy efficiency programs is one tool US states are using to address the utility throughput incentive.[29] Funds collected through a system benefits charge are turned over to an organization whose mission is to acquire energy efficiency on behalf of ratepayers.[30] Programs may serve only customers of the regulated utilities or customers of consumer-owned utilities, as well. Similar programs outside the US use a simple levy on electric utility sales revenue to establish a fund which finances measures implemented by third parties. Often there is a competitive process for allocating the funds.

The third-party model reduces the ability, but not the incentive, for utilities to act on their inherent bias against a reduction in sales. Because under this model the utility does not even face the conflict presented by energy efficiency, it can instead respond solely and fully to the throughput incentive.

US states that have adopted third-party administration, including Oregon, Vermont, and Wisconsin,[31] are places to look for evidence of the continued need for decoupling. In fact, commissions in these states still find decoupling a necessary tool to meet energy efficiency goals. The Oregon Public Utility Commission explained its rationale in a recent ruling approving decoupling for the largest utility in the state, Portland General Electric (PGE):

> [W]hile the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the ETO running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether it supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.[32]

Similarly, the Vermont Public Service Board has approved decoupling for Green Mountain Power[33] and Central Vermont Public Service (CVPS).[34] And the Wisconsin Public Service Commission recently approved decoupling for Wisconsin Public Service Corporation.[35]

A third-party provider operates most effectively when it works with the utility, has access to the utility's cost, usage, and demand data, coordinates projects to reduce load on the distribution circuits that face upgrade costs if load grows, and presents itself to customers as a partner with the utility. Without decoupling, the utility has an incentive not to work with the third-party provider.

Another factor elevates the need for decoupling in these states: Utilities can request approval from the state commission to include in base rates funding for energy efficiency that is incremental to the amount that can be acquired through the system benefits charge. Therefore, the utility still has significant control over the funding level, regardless of whether a third-party administrator runs the efficiency programs.

Clearing the Path to High Efficiency

Mounting evidence that efficiency is the least-cost, least-risk energy resource is leading to increasingly aggressive savings requirements. Climate change mitigation strategies compound this trend. However, neither requirements in law nor third-party administration of programs negate efficiency's fundamental conflict with the traditional utility business model, where earnings fall disproportionately with declining energy sales. Decoupling, which eliminates the conflict, is therefore a key policy tool for achieving high levels of energy savings through performance standards like an EERS as well as traditional utility programs, building codes, equipment standards, and consumer education.

[1]California, Colorado, Connecticut, Hawaii, Illinois, Iowa, Maryland, Michigan, Minnesota, Nevada, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Vermont, Virginia, and Washington. In addition to strict EERS requirements, ACEEE includes states with Commission-ordered efficiency targets, states that allow efficiency to count toward renewable energy standards, and states with a rate cap triggering a relaxation of EERS requirements. See Laura A. Furrey, Steven Nadel, and John A. "Skip" Laitner, ACEEE, *Laying the Foundation for Implementing a Federal Energy Efficiency Resource Standard*, March 2009, at http://aceee.org/pubs/e091.htm.

[2]The proposed standard in H.R. 2454 starts at six percent of sales in 2012 and rises to 20 percent of sales in 2020. State governors can petition the Federal Energy Regulatory Commission to allow utilities to meet up to two-fifths of the standard with electricity savings.

[3]H.R. 889 and S. 548. Annual targets are based on average energy deliveries during the two prior calendar years.

[4]Using a baseline period that lags behind the compliance year – say, by one year – provides utilities, regulators, and stakeholders with concrete energy targets (in kilowatt-hours or therms) for program planning and budgeting. The baseline may be fixed throughout the program, based on energy usage before the standard goes into place. Alternatively, a rolling baseline may be used. For example, the baseline may be average usage during 2007 and 2008 for the 2010 compliance year, average usage during 2008 and 2009 for the 2011 compliance year, etc. Under this approach, the more successful the efficiency programs, the lower the subsequent kWh/therm targets because the updated baseline reflects reduced energy sales.

[5]H.R. 889 and S. 548 (111th Congress) propose cumulative targets beginning in 2012. Annual figures representing incremental savings implied by the cumulative targets are from Furrey, et al., ACEEE, March 2009 (Table 1). According to ACEEE, programs to stimulate this level of savings would begin in 2011.

[6]*Energy Saving Trust, Energy Efficiency Commitment Report 2000-2001*, London, 2001.

[7]Ofgem, *Carbon Emissions Reduction Target (CERT) 2008-2011 Supplier Guidance*, London, 2007.

[8]David Crossley, "White certificates in Australia: States take the lead," *DSM Spotlight*, No. 32, January 2009, at http://www.ieadsm.org/Files/Exco%20File%20Library/Spotlight%20Newsletters/IEA%20DSM%20Spotlight%20newsletter-Issue%2032-January%202009.pdf.

[9]Energy efficiency certificates are also known as "white certificates" or "white tags." In January 2003 the New South Wales scheme became the first such trading system in the world. See D.J. Crossley, "Tradeable energy efficiency certificates in Australia," *Energy Efficiency*, Vol. 1, No. 4, November 2008, at http://www.springerlink.com/content/px01053860418332/fulltext.pdf.

[10]Maggie Eldridge, R. Neal Elliot, and Max Neubauer, ACEEE, *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned*, proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings. The study is based on state, regional, and national level analyses with study periods ranging from five to 20 years.

[11]For example, in developing its draft 6th Power Plan, the Northwest Power and Conservation Council estimates achievable, cost-effective conservation in the four-state region at 21 percent of the 20-year forecasted (medium-case) electric load. The identified conservation would meet about 85 percent of medium-case load growth in the region while significantly reducing both system cost and risk. Communication with Charlie Grist, Council senior analyst, August 14, 2009. Study results at http://www.nwcouncil.org/energy/crac/Default.htm.

[12]American Gas Association, *Natural Gas Utility Energy Efficiency Portfolios Report: 2007 Program Year*, December 2008, at http://www.aga.org/NR/rdonlyres/122417D7-E42E-49B4-8EE8-9AB26E421B4F/0/1208EEREPORT.pdf.

[13]Steven Nadel, ACEEE, Replies to Questions at the April 22, 2009, Hearing on Energy Efficiency Resource Standards, May 12, 2009.

[14]See NAPEE, 2006, at http://www.epa.gov/cleanenergy/documents/napee/napee_report.pdf.

[15]See Nadel.

[16]2010 in-service date. Jeff King, "Proposed Combined-cycle Power Plant Planning Assumptions: 6th Northwest Conservation and Electric Power Plan," Oct. 15, 2008, at http://www.nwcouncil.org/energy/grac/meetings/2008/10/Combined-cycle%20planning%20assumptions%20-%206P%20Draft%20101608.ppt#526,14,Natural%20gas%20price%20forecasts.

[17]The Energy Information Agency estimates the levelized cost of new conventional baseload plants in 2015 at about 6 cents per kWh (2006 dollars). See *Annual Energy Outlook 2008*, p. 69, at http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf.

[18]The natural gas price forecast is consistent with a recent forecast by Lazard, "Levelized Cost of Energy Analysis," presented at a meeting of the National Association of Regulatory Utility Commissioners, June 2008, at http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf.

[19]When efficiency displaces fossil-fuel generation, it has a negative carbon footprint.

[20]Sample calculation for a wires-only company. See Regulatory Assistance Project, *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission*, June 2008, p. 36, at http://www.raponline.org/Pubs/MN-RAP_Decoupling_Rpt_6-2008.pdf. A similar calculation for a vertically integrated utility resulted in a seven percent

change in earnings with each one percent change in utility sales.

[21]The exception is a utility with retail rates below wholesale power prices and no adjustment mechanism for fuel and purchased power. In this case, a decrease in sales can increase profits because the additional wholesale power revenue (or avoided wholesale power cost) may exceed the retail revenue loss. During the Western Energy Crisis in 2000-01, for example, utilities without a power cost adjustment had a strong incentive to conserve energy. But at that point it was too little, too late.

[22]Costs that vary directly with consumption and production – fuel, variable operation and maintenance, and purchased power costs – typically are excluded from the decoupling mechanism. Fuel and purchased power costs often are addressed through a separate adjustment mechanism.

[23]In the "accrual" version of decoupling, these prices are in place for an initial accrual period and subsequently adjusted to reflect over- or under-recovery of allowed revenue. In the "current" version of decoupling, the initial prices are never actually put in place; instead they are used as base prices against which decoupling adjustments are applied in each billing cycle.

[24]Allowed revenue may be the revenue requirement established in the last rate case or may be a formula designed to permit revenue to change over time to reflect inflation and productivity, to reflect customer growth, or to address another metric. Whatever the formula, decoupling assures that the targeted revenue is actually collected.

[25]Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," June 30, 2009, at http://www.raponline.org/Pubs/Lesh-CompReviewDecouplingInfoElecandGas-30June09.pdf.

[26]Whether expressed as kWh or therms saved or as reductions in greenhouse gas emissions.

[27]As previously noted, once an EERS is established, target and funding levels for efficiency are no longer at issue – at least for awhile. Absent such a performance standard, decoupling also would be needed to address the utility throughput incentive in proceedings that set these levels. And without decoupling, utilities will object to any ramp-up in EERS requirements.

[28]With appropriate customer consent.

[29]Other reasons for third-party administration may include increasing stakeholder involvement in program design and employing competition among energy efficiency service providers.

[30]The administering organization may be established by state statute, established by the Commission, or selected through competitive bidding.

[31]In Oregon, the third-party administrator is the Energy Trust of Oregon (ETO, www.energytrust.org). In Wisconsin, the Statewide Energy Efficiency and Renewable Administration is called Focus on Energy (http://www.focusonenergy.com). In Vermont, an "Energy Efficiency Utility" (EEU) procures energy efficiency for most utilities in the state. Efficiency Vermont currently serves as the EEU (www.efficiencyvermont.org).

[32]See Order No. 09-020 (Docket UE 197), Jan. 22, 2009, p. 27. The Commission clarified and modified the decoupling mechanism in Order No. 09-176, May 19, 2009, at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=14729.

[33]See order in Docket Nos. 7175 and 7176, pp. 3-4, at http://www.state.vt.us/psb/orders/2006/files/7175-7176finalorder.pdf.

[34]"Under alternative regulation, CVPS will set rates on the basis of customer load forecasts, taking into account the impacts of load changes arising from factors such as self generation, conservation, efficiency, and load management. These measures help to decouple CVPS's earnings from its retail sales volumes between rate cases, thereby promoting resource parity." See order in Docket No. 7336, Sept. 30, 2008, p. 40, at http://www.state.vt.us/psb/orders/2008/files/7336%20Final.pdf.

[35]Final decision in case number 6690-UR-119, Dec. 30, 2008, pp. 15-20, at http://psc.wi.gov/.

The Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602
www.raponline.org

Pass The Word

Pass this *Issuesletter* around to others and let us know whom we should add to our mailing list. As always, we welcome ideas for future issues.

The Regulatory Assistance Project

VERMONT
50 State Street, Suite 3
Montpelier, Vermont 05602
Tel (802)233-8199 Fax (802)223-8172

MAINE
PO Box 507, 110B Water Street
Hallowell, Maine 04347
Tel (207)623-8393 Fax (207)623-8369

NEW MEXICO
27 Penny Lane
Cedar Crest, New Mexico 87008
Tel (505)286-4486 Fax (773)347-1512

OREGON
429 North NE Nebergall Loop
Albany, Oregon 97321
Tel (541)967-3077 Fax (541)791-9210

ILLINOIS
455 Washington Boulevard #1
Oak Park, Illinois 60302
Tel (708)848-1632

CALIFORNIA
PO Box 210, 21496 National Street
Volcano, California 95689
Tel (209)296-4979 Fax (716)299-4979

AUSTRALIA
11 Binya Close, Hornsby Heights NSW 2077 Australia
Tel + 61 2 9477 7885 Fax + 61 2 9477 7503