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January 3, 2020

VIA ELECTRONIC MAIL
EnergyEfficiency@bpu.nj.gov

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: Energy Efficiency Technical Meeting II – "Cost Recovery Scenarios"
Comments of Atlantic City Electric Company

Dear Secretary Camacho-Welch:

On behalf of Atlantic City Electric Company ("ACE" or "the Company"), please accept these comments in response to the Notice entitled "Energy Efficiency Technical Meeting II – Request for Comments" ("Request for Comments"), issued by the Staff of the New Jersey Board of Public Utilities (the "Board"). Therein, Board Staff invited comments on four cost recovery scenarios for utility-run energy efficiency ("EE") programs.

ACE first incorporates by reference its comments of November 14, 2019 pertaining to EE cost recovery, which are attached hereto for convenience. Notably, ACE's November 14, 2019 comments recommend, among other things, decoupling to allow for the utilities to recover their lost revenues associated with EE programs.

In response to the four cost recovery scenarios set forth within Staff's Request for Comments, ACE finds Scenario 2 to be most amenable, provided the details around several aspects of the scenario are also found to be agreeable. For example, the proposed fixed-dollar incentives and penalties would need to be defined and documented, and it needs to be determined when such penalties or incentives will be applied, and if they will apply during the "ramp-up" period. Notably, however, ACE believes that customers would be better served by incentives and penalties that are increases or decreases in return on equity for EE program expenses, and not fixed-dollar amounts.

The Company also believes that it would be appropriate to establish a reasonable "dead-band" around the established EE goal, in which neither penalties nor incentives would be applied. For example, a reasonable dead-band would provide that no penalty nor incentive would be applied if a utility achieves between 85% and 115% of its assigned goal. This approach would allow for program flexibility and appropriate experimentation.

ACE appreciates the opportunity to provide these comments concerning EE cost recovery. The Company looks forward to providing further input on this subject in the future.

Respectfully submitted,

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Enclosure

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November 14, 2019

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RE: Atlantic City Electric Company
Comments Filed in Connection with Energy Efficiency Technical Meeting – Cost Recovery

Dear Secretary Camacho-Welch:

On behalf of Atlantic City Electric ("ACE" or the "Company"), please accept these comments in response to the Energy Efficiency Technical Meeting on Cost Recovery that took place on Thursday, October 31, 2019. The Technical Meeting continued stakeholder engagement on the energy efficiency transition and was focused on cost recovery, performance incentives and penalties related to implementation of New Jersey's next generation of energy efficiency and peak demand programs.

Background

The Clean Energy Act (the "Act") states that "[e]ach electric public utility and gas public utility shall file annually with the [New Jersey Board of Public Utilities (herein, the "Board")]) a petition to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, including but not limited to recovery of and on capital investment, and the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules, which shall be determined by the [B]oard pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1)."[1]

[1] N.J.S.A. 48:3-87.9(e)(1).

The Act further specifies that "[i]f an electric public utility or gas public utility achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive as determined by the [B]oard through an accounting mechanism established pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures for the following year. The incentive shall scale in a linear fashion to a maximum established by the [B]oard that reflects the extra value of achieving greater savings."[2]

Adjustments related to incentives or penalties determined by the Board may be made through either: (1) adjustments of the electric public utility's or gas public utility's return on equity related to energy efficiency or peak demand reduction programs or (2) a specified dollar amount reflecting the incentive structure.[3]

Overview

The Company appreciates the opportunity to participate in this important discussion, as policy decisions regarding cost recovery, performance incentives and penalties will directly impact program design, administration, implementation, and cost. Therefore, it is critically important that the Board select cost recovery mechanisms and incentives that will enable the State and its utilities to achieve the goals of the Act.

In order to develop a comprehensive strategy that can achieve high energy savings and corollary customer benefits while promoting effectiveness and certainty, it is necessary to allow full cost recovery, including lost sales revenue and a recovery of and on the utility's energy efficiency investment. This approach goes beyond mere compliance, optimizing use of the tools provided for in the Act to place energy efficiency and demand response as a resource on equal footing with other grid infrastructure improvements and as a preferred option for meeting customer needs. Additionally, since the Act allows for recovery of all reasonable and prudent costs incurred as a result of energy efficiency programs required pursuant to the legislation, the appropriate approach for determining which costs are "prudent and reasonable" (and, therefore, recoverable by the utility) is to define *a priori* that all costs related to programs and budgets approved by the Board should be deemed *per se* reasonable and prudent.

This is advantageous to customers because energy efficiency is typically the lowest cost resource; energy efficiency can avoid or delay more costly infrastructure investment, resulting in net savings to customers, regardless of whether they participate or not. Thus, policies that promote the continued growth in energy efficiency are good for all customers, with those participating customers receiving additional benefit through lower energy bills. According to the American Council for an Energy Efficient Economy ("ACEEE"), a comprehensive policy strategy for setting specific energy efficiency targets and for utilities to earn a return on efficiency investments is a best practice associated with achieving high energy savings, noting that a comprehensive policy requires: (1) program cost recovery; (2) full revenue decoupling; and (3) earnings opportunities

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[2] N.J.S.A. 48:3-87.9(e)(2).
[3] *See* N.J.S.A. 48:3-87.9(e)(4).

tied to performance targets. In this light, the Company's answers to the BPU-asked questions are below.

Question: Should recovery mechanisms be the same or different for programs administered or implemented by utilities versus non-utility parties?

Whether the programs are administered and delivered by the utilities or non-utilities, the cost recovery and incentive framework should aim to address the incentives and disincentives faced by the utility[4]. Ultimately, the utility is the entity realizing lost revenues due to customers' increased energy efficiency from program participation.

Program costs, regardless of program administrator, include costs related to administration, marketing, evaluation, measurement and verification and the cost of rebates. Lost investment, which will be realized by the utility regardless of program administrator, includes forgone return on investment from capital investments avoided by energy efficiency programs. Lost sales revenue (lost revenue), also realized by the utility, includes forgone recovery of fixed costs embedded in volumetric rates due to lower electricity sales. In order to achieve the goals of the Act, utilities should be compensated for these impacts as a result of implementing the energy efficiency programs, regardless of who administers them.

Topic 1: Recovery of Program Costs

Question: Should costs associated with efficiency program investments be expensed or amortized? If amortized, what is the appropriate amortization period, and what should the rate for the carrying costs be?

Under generally accepted accounting principles ("GAAP") for regulated utilities, "[r]egulators capitalize expenses that, in unregulated firms, would be expensed in the current accounting period. Those capitalized costs are then amortized as they are included in rates."[5] The Company recommends amortization of program costs and calculation of a return on programs and services, with costs amortized over a common period with other New Jersey utilities. According to the National Action Plan for Energy Efficiency ("NAPEE")[6], a seminal work on the financial

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[4] In the Maryland Collaborative Report, questions over whether the cost recovery discussion extended beyond utility-managed programs to include, for example, cost recovery for AMI, were resolved in favor of a focus on utility-managed programs. To the extent that this question references a similar uncertainty, the Company supports the Maryland resolution. *See* Public Service Commission of Maryland, Case No. 9111, Report of the Advanced Metering Initiatives and Demand Side Management Collaborative, filed July 6, 2007, p. 7.

[5] David W. Wirick, The National Regulatory Research Institute ("NRRI"), and John J. Gibbons, California Public Utilities Commission (Retired), Generally Accepted Accounting Principles for Regulated Utilities: Evolution and Impacts, p. 5, *available at* https://pubs.naruc.org/pub/FA85D820-AE63-44EE-A453-F83281D70355.

[6] *See* U.S. Environmental Protection Agency ("EPA") and U.S. Department of Energy ("DOE"), National Action Plan for Energy Efficiency, Aligning Utility Incentives with Investment in Energy Efficiency (2007), Chapter 4.3 Capitalization and Amortization of Energy Efficiency Program Costs, *available at* https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf. "A principle argument made in favor of capitalizing energy efficiency program costs is that this treatment places demand-and supply-side expenditures on an equal financial footing." The National Action Plan for Energy Efficiency was a private-public initiative to create a

structure of energy efficiency programs, advantages to amortization and capitalization include the following:

- amortization places energy efficiency investments on more of an equal footing with supply-side investment with respect to cost recovery;
- capitalization of energy efficiency programs can defer the need for new supply-side investment, which decreases customer costs in the long-run;
- amortization allows customers to pay for the measure over its useful life; and
- amortization smoothes the rate impacts of large swings in annual energy efficiency spending.

The creation of a regulatory asset that is recovered over a period of time through rates represents a compromise between immediately expensing a cost (which would mean an immediate loss to shareholders) and an immediate charge to ratepayers (which would mean an immediate increase in rates).[7] In light of this, the choice of amortization period for recovery of program costs should balance rate impacts. A shorter amortization period will result in a higher annual rate impact, while a longer amortization period will spread out costs.

When determining the appropriate amortization period for energy efficiency investments, the Company believes that the Board should apply the fundamental principles of ratemaking. Specifically, the period of cost recovery for an investment should correspond with the period over which customers receive the benefits provided by the investment. In following this principle, customers benefit from a utility investment at the same time as they pay for that investment. This approach would put energy efficiency investments on an equal footing with supply side investments, from both a shareholder and customer perspective, would reduce the cost burden on customers, and would better match the recovery period with the time period during which the investments are providing benefits.

Regarding process, ACE recommends that a regulatory asset be created for the unamortized balance with a rate of return based on the weighted average cost of capital ("WACC") earned on this balance.[8] A utility's revenue requirement should equal the return from the regulatory asset plus the amortization realized from the capitalized program costs, with the rate for any given

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sustainable, aggressive national commitment to energy efficiency through the collaborative efforts of gas and electric utilities, utility regulators, and other partner organizations. Such a commitment can take advantage of large opportunities in U.S. homes, buildings, and schools to reduce energy use, save billions on customer energy bills, and reduce the need for new power supplies. NAPEE was a private-public initiative to create a sustainable, aggressive national commitment to energy efficiency through the collaborative efforts of gas and electric utilities, utility regulators, and other partner organizations. NAPEE's recommendations continue to be advanced to this day under the EPA/DOE-led State and Local Government Energy Efficiency Action Network (SEEAction) initiative.

[7] *See* David W. Wirick, The National Regulatory Research Institute ("NRRI"), and John J. Gibbons, California Public Utilities Commission (Retired), Generally Accepted Accounting Principles for Regulated Utilities: Evolution and Impacts, p. 5, *available at* https://pubs.naruc.org/pub/FA85D820-AE63-44EE-A453-F83281D70355

[8] *See* Christina Simeone, Rate Decoupling: Economic and Design Considerations, Kleinman Center for Energy Policy (April 2016), p. 16, *available at* http://ipu.msu.edu/wp-content/uploads/2017/09/Rate-Decoupling-Simeone-2016.pdf. "[R]ealization of decoupling's effectiveness to achieve policy goals may well be predicated on the [rate of return] equaling the firm's cost of capital."

program year reflecting the revenue requirement divided by the forecasted sales. Advantages to this method include matching program costs with the time period in which the energy efficiency benefits are received, which is a key ratemaking principle.[9] Amortization with a minimum of a five-year schedule avoids intergenerational inequities and initial rate shock, putting energy efficiency on the same playing field as traditional "poles and wires" investments from an earnings perspective.

The Company recommends recovery of amortized costs through a system benefits charge, as this is the method used in Maryland for that state's successful EmPOWER programs.[10] Through this method, the customer realizes a per-kilowatt-hour surcharge on their bill to fund energy efficiency programs. The surcharge amount is established by an annual filing by each utility, subject to approval based on the level of forecasted expenditures for the next program year and any required "true-up" adjustments for over or under collections from the prior year.[11] Under the Maryland model, expenses associated with conservation and energy efficiency programs are amortized over a five-year period, and capital investments are amortized over a period that represents the useful life of the investment.[12]

With regard to the appropriate return on equity value for energy efficiency, ACE recommends use of the WACC as approved by the Board. According to GAAP for regulated utilities, "[t]he weighted average cost of capital is often used as the overall rate of return when determining revenue requirements."[13] Whether the item is a transformer or other equipment, or energy efficiency and demand response programs, the WACC represents the utility's costs to finance all of its distribution investments. WACC ensures that energy efficiency investments are on a level playing field with all other competing distribution investments, and therefore encourages utilities to continue to support energy efficiency by directly addressing the potential financial bias against investment in energy efficiency programs.

Applying a utility's authorized return on equity is fully consistent with other statutes addressing public utility investments in energy efficiency programs. For example, the Act permits utility investments in energy efficiency programs and provides that such investments "may be

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[9] *See* Maryland Public Service Commission, Cost of Service Ratemaking Overview Before the House Economic Matters Committee (January 2019), slide 6, available at https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Ratemaking-Overview-House-ECM_01102019.pdf. It is a key ratemaking principle that there is a "need to ensure that revenues, expenses and rate base use consistent periods" which "assures that costs and benefits affect similar customers during the same period."

[10] *See* Public Service Commission of Maryland, The EmPOWER Maryland Energy Efficiency Act Report of 2019, filed July 2019, p. 2, *available at* https://www.psc.state.md.us/wp-content/uploads/2019-EmPOWER-Maryland-Energy-Efficiency-Act-Standard-Report.pdf "Program-to-date, the Utilities' EmPOWER Maryland programs have saved a total of 8,092,181 megawatt-hours ("MWh") and 2,335 megawatt ("MW"). The expected savings associated with EmPOWER Maryland programs is approximately $9.0 billion over the life of the installed measures for the EE&C programs."

[11] Public Service Commission of Maryland, Case No. 9111, Order No. 81637 dated September 28, 2007, p. 6-7

[12] Public Service Commission of Maryland, Case No. 9111, Order No. 81637 dated September 28, 2007, p. 6

[13] David W. Wirick, The National Regulatory Research Institute ("NRRI"), and John J. Gibbons, California Public Utilities Commission (Retired), Generally Accepted Accounting Principles for Regulated Utilities: Evolution and Impacts, p. 159, *available at* https://pubs.naruc.org/pub/FA85D820-AE63-44EE-A453-F83281D70355.

eligible for rate treatment approved by the [B]oard, including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas."[14] Allowing for a return on equity also ensures that utilities offer necessary but often more expensive programs, like income-qualified ones, in its program portfolio. Otherwise, the motivation could be to design a program portfolio based on cost minimization, which may only allow for programs that meet the needs of a specific customer class. While the provision is permissive, the Board's well-established practice has been to permit recovery of prudently incurred costs associated with energy efficiency programs, including a return of and on the utility's capital investment at the utility's authorized return on equity.[15]

Finally, setting the rate of return based on the utility's WACC will give decoupling the best chance of succeeding. According to a 2009 study by Steve Kihm, Research Director of the Energy Center of Wisconsin, decoupling has the best chance of working if "a regulator keeps allowed rates of return close to a utility's cost of capital. … Under this condition, decoupling will make the utility largely indifferent between sales promotion and energy efficiency."[16]

Question: Should costs be allocated by sector (e.g., residential, commercial, industrial)? If yes, how would you recommend doing the allocation?

In order to preserve administrative simplicity, costs should not be allocated by sector. These programs advance New Jersey's specific energy, environmental, economic and equity policy objectives by providing social benefits to all. Further, allocating by sector would limit the flexibility to direct funds where they are most needed. One potential exception could be self-direct programs for large commercial and industrial customers, in which industrial customers concerned about perceived inequities in what they contribute versus what they receive in the form of rebates, may choose to establish their own funding pool from which to draw incentives, in which the extent of rebates available to them would be matched by what they pay in.[17]

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[14] *See* N.J.S.A. 48:3-98.1(a)(1); N.J.S.A. 48:3-98.1(b).

[15] The Board has repeatedly authorized utilities to earn their full authorized ROE on energy efficiency investments. See, e.g., I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge ("2014 PSE&G Green Programs Cost Recovery Filing"), Amended Order Approving Stipulation, BPU Docket Nos. ER14070651 and GR14070652 (dated May 19, 2015) (including numerous schedules reflecting inclusion of a return of and on investments); In re the Petition of South Jersey Gas Company for Approval of an Energy Efficiency Program with an Associated Energy Efficiency Tracker Pursuant to N.J.S.A. 48:3-98.1, BPU Docket No. GO12050363, Order (dated June 21, 2013); I/M/O the Petition of South Jersey Gas Company for Approval to Continue Its Energy Efficiency Programs and Energy Efficiency Tracker Pursuant to N.J.S.A. 48:3-98.1, BPU Docket No. GR15010090, Order (dated August 19, 2015) at Paragraph 22 of the approved Stipulation.

[16] Steve Kihm, When Revenue Decoupling Will Work and When It Won't (October 2009), *available at* https://www.seventhwave.org/sites/default/files/kihmdecouplingarticle2009.pdf.

[17] *SEE*Action Report, Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector (March 2014), p. 41, *available at* https://energy.gov/eere/amo/downloads/industrial-energy-efficiency-designing-effective-state-programs-industrial-sector.

Topic 2: Potential for Recovery of Lost Revenues

Question: Should there be a mechanism to recover lost revenues?

Yes, a mechanism for the utility to recover lost revenues is necessary to stabilize utility revenue and address the Throughput Incentive, which has been identified by many as the primary barrier to aggressive utility investment in energy efficiency.[18] (The Throughput Incentive is a utility's incentive to increase sales as a means of increasing revenue and profits.) Utility recovery of lost revenues is authorized by the Act and New Jersey's Regional Greenhouse Gas Initiative (or RGGI) law, indicating that the State recognizes the need for lost revenue recovery to enable successful programs.[19]

Energy efficiency reduces the sales revenue collected by utilities because the rate case, where the revenue requirement is determined, assumes a certain level of sales over which the revenue will be recovered. If energy efficiency exceeds what is projected in the sales forecast, the utility will fail to recover its allowed revenue requirement, including the contribution to fixed costs and its margin (profit). The sales can be trued up in the next rate case, but the margin is lost, hence the term "lost margins." Because of lost margins and under-recovery of fixed costs, utilities have a disincentive to promote energy efficiency to their customers because these programs result in less use of the utilities' product.

Question: If the Board allows for recovery of lost revenues, what should the lost revenue recovery mechanism be?

ACE recommends full decoupling for recovery of lost revenues. The primary objective of decoupling is to remove the Throughput Incentive – a utility's incentive to increase sales as a means of increasing revenue and profits. By removing the Throughput Incentive, the utility is willing to promote energy efficiency as revenues will not decrease from customer adoption of energy-saving measures. Decoupling also stabilizes utility revenues, protecting the utility against lost revenues and customers against increasing costs. Additionally, no forecasting technique can ever be exact; full decoupling addresses the shortfalls of forecasting while removing the Throughput Incentive.

Decoupling is a rate adjustment mechanism that separates a utility's revenue recovery from the volume of sales.[20] In contrast to traditional regulation that sets rates and lets revenue fluctuate with sales volumes, decoupling allows regulators to set the revenue target and periodically adjusts the rate to ensure recovery of the allowed revenue. Rate adjustments recover uncollected approved costs or refund recoveries in excess of the approved revenue over a given period. As such, under

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[18] *See* NAPEE, Aligning Utility Incentives with Investment in Energy Efficiency (2007), ES-3.
[19] *See* N.J.S.A. 48:3-98.1.
[20] Because of broader revenue implications, decoupling is typically addressed in separate proceeding or as part of a rate case, not in an energy efficiency docket.

decoupling, a utility will recover its allowed revenue requirement – as set by regulators -- regardless of changes in sales.[21]

Decoupling does not result in an increase in costs for customers. Rather, it is a revenue stabilization mechanism that allows utilities to recover the revenue authorized in a rate case proceeding. The only increased costs related to decoupling are from carrying charges on balances in the balancing/deferral account, which are common in utility accounting.

It is instructive to note that decoupling mechanisms have been in place for over a decade. In fact, the New Jersey gas utilities have operated under a form of decoupling for 13 years. A May 2013 study titled A Decade of Decoupling for US Energy Utilities found that decoupling rate adjustments are mostly within +/- two percent of retail rates, resulting in minor positive and negative rate adjustments that are less than other price fluctuations, such as the price of natural gas.

Question: If the Board allows for recovery of lost revenues, what methods should the Board employ to calculate lost revenues associated with energy savings?

The scope of decoupling mechanisms can vary, but are generally characterized as full, partial or limited. Under full decoupling, a utility will receive its approved revenue requirement due to any and all variations in sales (*e.g*., due to weather, efficiency, economic activity, etc.).[22] Under partial decoupling, a utility recovers only a portion of the difference between allowed and actual revenue (*e.g.*, 90% of the revenue shortfall is recovered through the rate adjustment).[23] Under limited decoupling, only specified causes of variations in sales result in rate adjustments. Causes could include weather, energy efficiency programs, and/or economic conditions.[24]

The allowed revenue requirement is typically determined as part of a general rate case and includes fixed costs and a rate of return. Under a total revenue model, the total allowed revenue is predetermined and will not change between rate cases. In contrast, the revenue-per-customer model recalculates the allowed revenue requirement based on customer count, recognizing that the changes in the number of customers can affect costs.

Decoupling price adjustments can be implemented on a deferral basis or billing cycle basis. In deferral decoupling, a utility calculates the over or under collection of revenue in a balancing or deferral account. The account will track under-recovered or excess revenues for true-up in the following month Rate adjustments can be implemented monthly, quarterly, semi-annually, or annually. In Maryland, for example, decoupling price adjustments are implemented on a deferral basis, with the rider calculated on a monthly basis accounting for any true-up (over or under

[21] *See* NAPEE, Aligning Utility Incentives with Investment in Energy Efficiency (2007), ES-3.
[22] *See* Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, p. 11-13, *available at* http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf.
[23] *Ibid.*
[24] *Ibid.*

recovery in the previous month).[25] For this initiative, the Company recommends following the Maryland model by using deferral decoupling.

Question: If the Board allows for recovery of lost revenues, should other factors (e.g., weather, nonprogram-related reductions) be taken into account?

The Company recommends full decoupling, which looks at total level of sales regardless of why changes in sales occurred. Parsing out why sales were lower in a given period is analytically intensive with questionable accuracy. Many factors affect sales, which makes it extremely difficult to confidently determine causes. Additionally, no forecasting technique can ever be exact. Full decoupling is an elegant solution to the shortfalls of forecasting that also addresses the Throughput Incentive and ensures that customers never overpay for distribution services.

Some limited or partial decoupling mechanisms use weather-normalized use per customer to calculate the amount of under or excess revenue recovery. By excluding weather, the utility retains the risk that weather will reduce revenues, but retains the benefit if weather increases sales and revenues. However, weather normalization can result in rate adjustments that do not reflect the differences between actual and authorized revenue levels. For example, in Minnesota, during CenterPoint Energy's 2012 evaluation period, the weather was much warmer than the normal weather assumed in the rate case.[26] As a result, the utility's actual non-commodity gas revenues were $20 million lower than the weather-normalized revenues used in the rate adjustment calculation. However, the weather-normalization of actual revenues showed a total over-collection of $2.6 million, resulting in a refund to customers even though the utility significantly under-recovered the allowed revenue.[27]

Question: If the Board allows for recovery of lost revenues, should authorized return on equity be subject to adjustment based on reduced risk?

No, the authorized return on equity should not be subject to adjustment based on reduced risk.

While some may argue that a decoupling mechanism reduces earnings volatility, this reduced risk should not be reflected in a lower return on equity. According to "A Decade of Decoupling," several state public utility commissions have noted the absence of empirical

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[25] *See* Public Service Commission of Maryland, Case No. 9111, Order No. 81637 dated September 28, 2007, pp. 6-7.

[26] *See* Public Utilities Commission of the State of Minnesota, Docket No. G-008/GR-17-285, Direct Testimony of Mr. Burl M. Drews re Revenue Decoupling Rider, August 2, 2017, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B2013A45D-0000-C6BF-ABF5-2F025D149F60%7D&documentTitle=20178-134460-06.

[27] *See* Public Utilities Commission of the State of Minnesota, Docket No. G-008/GR-17-285, Direct Testimony of Mr. Burl M. Drews re Revenue Decoupling Rider, August 2, 2017, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B2013A45D-0000-C6BF-ABF5-2F025D149F60%7D&documentTitle=20178-134460-06.

evidence regarding how, if at all, decoupling affects risk.[28] There has also been a reluctance to make a specific adjustment separate from all the other considerations influencing a decision regarding return on equity. Other arguments against return on equity reductions include:

- Decoupling adjustments can include refunds, which represent lost opportunities for additional revenue. It is not clear that the risk of under-collection outweighs the lost opportunity of collecting additional revenues.
- The decoupling adjustments are likely to be small. It follows that the impact on risk is also small.
- When the mechanism is limited in scope, the impact on risk is also limited and may be negligible.
- Other risk changes may offset the effect of decoupling.
- Where decoupling is implemented to support enhanced energy efficiency efforts, adopting a reduction in allowed return on equity essentially punishes a utility for pursuing energy efficiency programs.
- Research by the Brattle Group found that decoupling does not affect the estimated cost of capital for utilities in a statistically significant way.[29]
- Not all risks or sources of variance in earnings affect the cost of capital equally, because investors can simply avoid certain risks. Simply reducing total risk does not imply that the cost of capital has been reduced. The risk reduced must be part of a company's business risk to affect its cost of capital, so only reductions in business risk justify a reduction in a regulated company's allowed return on equity.

Topic 3: Performance Incentives and Penalties

Question: How should performance incentives be structured? How should performance penalties be structured?

As noted above, the Act at N.J.S.A. 48:3-87.9(e)(2) provides that cost recovery should include performance incentives or penalties as determined by the Board through an accounting mechanism established pursuant to N.J.S.A. 48:3-98.1. Common performance incentives include shared savings, a rate of return adder, and performance targets. The Company recommends application of performance targets to incent positive program outcomes. A performance target allows award of a percentage of spend for achieving or exceeding threshold performance goals. For a performance target to be effective, any incentive formula must be consistent with desired

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[28] Pamela Morgan, Graceful Systems LLC, A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations (May 2013), *available at* https://www.leg.state.nv.us/App/InterimCommittee/REL/Document/2613.

[29] The Brattle Group, The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation (March 2014), p.17, *available at* https://brattlefiles.blob.core.windows.net/files/6081_effect_of_electric_decoupling_on_the_cost_of_capital.pdf.

outcomes; ensure a reasonable magnitude for incentives; tie incentive formula to actions within the control of utilities; and allow incentives to evolve.[30]

ACE does not believe that a penalty is required, as it is already subject to reasonableness review, and notes that inappropriately strident targets and/or earnings eligibility thresholds can have the effect of sending counterproductive signals to the utility regarding performance. Penalties for program non-performance should be reserved for a complete lack of commitment. To meet high energy-saving goals, experimentation and innovation is warranted, and there should be an allowance for learning the market. Therefore, a program administrator offering a program portfolio with a good-faith effort should not be penalized. For this reason, if the Board chooses to employ penalty provisions, a deadband (or neutral zone) should be included, representing a level of energy savings in which there are no incentives awarded and no penalties assessed. For example, Idaho Power utilized a neutral zone in its Performance-Based Demand-Side Management Incentive Pilot in 2007, in which "[a]nything in between 5.0% and the annual target was a deadband for which there was no incentive or penalty."[31]

Question: Should incentives and penalties be handled as a percentage adjustment to earnings or as specific dollar amounts? Why? How?

Regarding penalties, ACE is already subject to a reasonableness review, so a penalty mechanism is not required.

Performance incentives should be achievable, linear, meaningful, and clear in order to allow utilities to achieve the long-term goals of the Act. The Company recommends that incentives should be a percent of net benefits. The objective of the performance mechanism should be to incent, induce, and reward consistently excellent performance, not to strive for symmetry between rewards and penalties in a manner that makes energy efficiency programs seem like more of a gamble from the utility perspective.

If the Board chooses to pursue penalties, they should be specified as dollar amounts as opposed to being tied to net benefits (*i.e.*, increasing net benefits should not increase penalties to avoid a perverse incentive to minimize risk through reduction of net benefits). According to ACEEE, **"**the most common thresholds for shared net benefits mechanisms are in the range of 70–85% of energy savings targets. Typically, the amount of the incentive itself is calculated as

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[30] *See* Melissa Whited, Tim Woolf, Alice Napoleo, Synapse Energy Economics, Inc., prepared for the Western Interstate Energy Board, Utility Performance Incentive Mechanisms – A Handbook (March 2015), p. 4, *available at* https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

[31] Sara Hayes, Steven Nadel, Martin Kushler, and Dan York, ACEEE, Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency (January 2011), p. 35, citing 44 Performance-Based Demand-Side Management Incentive Pilot 2007 Performance Update. Filed with the Idaho Public Utilities Commission March 14, 2008.
http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0632/company/20080317PB%20DSM%202007%20UPDATE.PDF
available at http://aceee.org/sites/default/files/publications/researchreports/U111.pdf.

percentage of the net benefits of energy savings achieved."[32] For example, New Hampshire offers utilities a performance incentive of up to 8-12% of total program budgets for meeting cost effectiveness and savings goals.[33] Hawaiian Electric must meet four energy efficiency targets to be eligible for incentives calculated based on net system benefits up to 5%.[34]

Question: Should incentives and penalties be scalable based on performance? If so, in what manner?

Yes, incentives should be scalable based on performance. A near-universal characteristic of energy efficiency incentive mechanisms is that they all provide greater rewards for additional energy savings up to the level of the maximum incentive.[35] In this initiative, the Company respectfully submits that incentives should be tied to performance such that the award increases as achievement increases. For example, Arizona allows for shared savings calculated as a share of net economic benefits up to 10% of total demand-side management spending.[36] In Minnesota, utilities are eligible for a specific share of net benefits based on cost effectiveness test; at 150% of the savings target, utilities are eligible to receive 30% of the conservation expenditure.[37]

Question: How should incentives and penalties be reconciled? Should incentives and penalties be "refunded" to ratepayers through rate reduction?

As stated previously, ACE recommends that forecasted program costs are capitalized and amortized. A regulatory asset should be created for the unamortized balance with a return, based on the WACC, earned on this balance.[38] For reconciliation of incentives and penalties, both can become part of the regulatory asset account that feeds the surcharge, with symmetrical adjustments allowing for surcharges when incentives are awarded and refunds when penalties are assessed.[39]

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[32] Seth Nowak, Brendon Baatz, Annie Gilleo, Martin Kushler, Maggie Molina, and Dan York, ACEEE, Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency (May 2015), p. 10, *available at* https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

[33] ICF International, Briefing for the Maryland Energy Administration, Utility Performance Standards, Oversight, and Cost Recovery (September 2007), p. 29.

[34] *Ibid.*

[35] Seth Nowak, Brendon Baatz, Annie Gilleo, Martin Kushler, Maggie Molina, and Dan York, ACEEE, Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency (May 2015), p. 10, *available at* https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

[36] ICF International, Briefing for the Maryland Energy Administration, Utility Performance Standards, Oversight, and Cost Recovery (September 2007), p. 29.

[37] *Ibid.*

[38] *See* Christina Simeone, Rate Decoupling: Economic and Design Considerations, Kleinman Center for Energy Policy (April 2016), p. 16, *available at* http://ipu.msu.edu/wp-content/uploads/2017/09/Rate-Decoupling-Simeone-2016.pdf. "[R]ealization of decoupling's effectiveness to achieve policy goals may well be predicated on the [rate of return] equaling the firm's cost of capital."

[39] *See* Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, p. CS57, *available at* http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf. "The allocation of revenue regulation revenue surpluses or deficits should be symmetrical so that overpayments are credited to customers just as underpayments are paid by those same customers."

Question: If the Board establishes performance incentives and penalties, what level of total incentives and penalties is reasonable?

Capping total incentives and penalties can promote reasonableness and certainty. If the Board wishes to establish a cap on total incentives and penalties, this can be done as an absolute cap or a relative cap. According to ACEEE, "[s]ome caps are absolute dollar amounts, such as in those states that budget a set pool of funds from which incentives may be awarded."[40] Here, as the Company is recommending an award of a percentage of spend for achieving or exceeding threshold performance goals, a relative cap is more appropriate, and can be "expressed as a maximum percentage of program budgets or percentage of total net benefits." [41]

Thank you for your attention and consideration in this matter. Feel free to contact the undersigned if you have any questions or if ACE can be of further assistance.

Respectfully submitted,

/jpr
Philip J. Passanante
An Attorney at Law of the
State of New Jersey

[40] Seth Nowak, Brendon Baatz, Annie Gilleo, Martin Kushler, Maggie Molina, and Dan York, ACEEE, Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency (May 2015), p. 10, *available at* https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

[41] Seth Nowak, Brendon Baatz, Annie Gilleo, Martin Kushler, Maggie Molina, and Dan York, ACEEE, Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency (May 2015), p. 10, *available at* https://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

January 3, 2020

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Re: Energy Efficiency Cost Recovery Stakeholder Meeting 2, Hypothetical Cost Recovery Scenarios

The Energy Efficiency Alliance of New Jersey, the Natural Resources Defense Council, the New Jersey Sustainable Business Council, and the US Green Building Council-NJ submit the following Best Scenario/Straw Proposal based on the 4 cost recovery scenarios presented by the New Jersey Board of Public Utilities ("BPU"). We believe that the Cost Recovery scenario presented below will put New Jersey on the path to be a leader national leader in energy efficiency, provide good paying jobs to the state's residents, and electrify the grid in an equitable and environmentally conscious way. The combination of tools that we chose to use are for this specific hypothetical cost scenario. Please do not take this as our final viewpoint on the issues presented in this comment and see additional group individual comments for further detail on individual group viewpoints.

Best Scenario

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Full Symmetrical Decoupling
Incentives/Penalties	% of return (Weighted by QPI Performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill
WACC	Base Rate Case
Rate Cap	No Cap

- *For comparison purposes we wanted to note that this proposal is Scenario 3 with one change. We have changed Lost Revenues Mechanism to Full Symmetrical Decoupling the change is expanded upon below.*

The Scenario selection above, and explained in more detail below, represents one of the best pathways to encourage utilities to fully engage with the policy mandates of the Clean Energy Act ("CEA"). Beyond energy efficiency, the state is currently pursuing robust policies in support of building decarbonization and electrification, electric vehicle deployment, nation-leading procurement of wind resources, and a complete overhaul of its solar incentive program. These changes, along with others outlined in the Energy Master Plan ("EMP") will have a profound effect on the utility business model. As such, the current paradigm of the utility business model and associated cost recovery policies must similarly be transitioned away from one that rewards utilities for capital investment and volumetric energy sales, to one that focuses on achieving New Jersey's clean energy policies.

Explanation of Factors

Asset/Investment Treatment: Amortization
Recovery Period: Weighted-Life
We recommend that assets/investments be amortized over the weighted-life of the measure.

For New Jersey to make the drastic changes in its energy generation and consumption needed to meet the goals of the Clean Energy Act, the state needs to enact policies that prioritize efficiency through aligning utility financial goals with state policy goals. Amortization of energy efficiency asset/investments over the weighted useful life of the measure puts energy efficiency on equal footing to investment in infrastructure and the grid and prevents potential bill shocks associated with contemporaneous recovery of program expenses. For utilities, investment in infrastructure and delivery is encouraged through amortization of these assets which provides financial security and incentives for stockholders. Amortization of investments in energy efficiency, similar to these investments, will encourage utilities to change priorities from building out the grid to energy efficiency.[1] Additionally, money invested by utilities in energy efficiency programs avoids the need for investment in traditional utility infrastructure.[2]

Amortization also protects consumers as it reduces bill impacts. Amortization of energy efficiency will spread out investment costs and rate impacts for customers; allowing for New Jersey to ramp up in investment and comply with the mandates of the Clean Energy Act without a rate shock to customers. And, amortization of programs allows for customers to maintain control over their bill as programs for energy efficiency are financed through rates and usage instead of a flat fixed fee. Therefore, the best path forward is to use an amortization mechanism with a recovery period over the weighted life of the measure.

Lost Revenues: Full Symmetrical Decoupling
We recommend Full Symmetrical Decoupling.

Over the course of this proceeding the above-signed groups have submitted numerous comments that discuss revenue decoupling and other cost recovery mechanisms and incorporate those comments by reference.[3]

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[1] ACEEE, Aligning Utility Business Models with Energy Efficiency, available at: https://aceee.org/sector/state-policy/toolkit/aligning-utility.

[2] Dan York et al., Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation, December 2013, American Council for an Energy-Efficient Economy, available at https://aceee.org/research-report/u133.

[3] *See*, NRDC *et al. In the Matter of the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs—Docket No. QO19010040* (Feb 15.), *available at*: https://s3.amazonaws.com/njcepfiles/Binder1.pdf; *NRDC, NJ Draft Energy Master Plan Comments* (Sept. 14 2019), *available at* https://nj.gov/emp/pdf/draft_emp/NRDC%20NJ%20Draft%20Energy%20Master%20Plan%20comments.pdf. *See, Energy Efficiency Alliance of New Jersey, In the Matter of the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs—Docket No. QO19010040 (Feb 15.), available at https://drive.google.com/file/d/1rJj3nQJBvj4Gwk2RHPIOHAuNdP67Zs92/view; See, Energy Efficiency Alliance of New Jersey Comments on the Draft Energy Master Plan (September 16, 2019), available https://drive.google.com/file/d/1ArzYJCilTBASThDeGwgBbCefleNxum0X/view; See also, Energy Efficiency Alliance*

For the purposes of clarifying the mechanisms provided by the BPU we have provided definitions below for each component.

> Full Symmetrical Decoupling: similar to the setting of a budget, determines a utility's full revenue in a rate base case with adjustment mechanisms to compensate for over or under earnings. To implement this method of decoupling, the Board would take the utility's determined revenue requirement and determine the sales price per-customer class based on expected usage to ensure the utility achieves that revenue. If the utility over or under earns, there is a built-in correction mechanism that will adjust rates up or down depending on projected versus actual sales. States that utilize this mechanism often statutorily mandate rate cases so to ensure a check on utility earnings and spending. Generally, this mechanism means that a utility's profitability will be "determined by how well it operates within that budge" and "[a]ctual sales will not have an impact on the budget."[4]

> Limited Decoupling or Lost Revenue Adjustment Mechanisms (LRAMs): separates specified causes of variations in sales that result in decoupling adjustments such as weather or utility-operated energy efficiency programs.[5] These mechanisms only impact a portion of utilities rate, allowing for them to earn a guaranteed return on the decoupled variation in addition to whatever other revenues may come from other energy sales with no cap on earnings. LRAMs fail to address the core financial issues that deter utility participation in energy efficiency programs as revenues are still tied to sales.[6]

> Partial Decoupling: insulates a portion of the utility's revenue collections from deviations of actual from expected sales. Any variations result in a partial true-up of the separated portion of utility revenues. Because this mechanism only reconciles a portion of a utility's profits and other profits are still tied to sales, it too fails to address the core financial issues that deter utility participation in energy efficiency programs.[7]

Both LRAMs and Partial Decoupling simply compensate utilities for perceived revenue losses without properly addressing the core issue - the throughput incentive, which incentivizes utilities to recover fixed costs through increasing the volumetric sale of energy.[8] Additionally, they allow utilities to earn a guaranteed income while also profiting from electricity sales,

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of New Jersey, October 30, 2019 Energy Efficiency Stakeholder Meeting- Programs (Nov. 2019), available at: https://drive.google.com/file/d/0B_S_sZFYtn6aZUZQa1ZsbnJNOXRYbF9lcGZZTHl1SGw0Sk5j/view; See also, Energy Efficiency Alliance of New Jersey, New Jersey Energy Efficiency Stakeholder Group, Energy Efficiency Technical Meeting – Cost Recover, October 31, 2019 (Nov. 14, 2019), available at https://drive.google.com/file/d/1I6fbyAJh4Kef46JaEiHwIbhPP_eOx6wy/view.

[4] Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016, pg. 11, available at: https://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities/.

[5] *Id.* at 12 - 13.

[6] *Id.* at 13.

[7] *Id.* at 13.

[8] Annie Gilleo, et al., Valuing Efficiency: A Review of Lost Revenues Adjustment Mechanism, June 2015, American Council for an Energy-Efficient Economy, available at https://aceee.org/sites/default/files/publications/researchreports/u1503.pdf.

putting the ratepayers at risk of overpaying the utilities. Therefore, the BPU should avoid mechanisms such as LRAM and Partial Decoupling, as they are not a reasonable "middle ground" between traditional cost-of-service ratemaking and full revenue decoupling.

In addition to being a mere half-measure for cost recovery, LRAM's and limited decoupling are difficult to incorporate as a cost recovery mechanism as they are administratively burdensome and technically complex.[9] For example, the BPU in its Program Administration Straw Proposal recommends three models for program administration; utility administration, state administration, and joint administration. Under an LRAM or partial decoupling mechanism, the BPU and stakeholders would have to undertake an analysis to determine whether revenue erosion is the result of energy efficiency as opposed to some other factor such as the economy or weather. Then, the BPU would have to determine the relative impact of the three separately administered programs on revenue recovery. Further, after the analysis is complete, and perceived revenue impacts of utility run energy efficiency programs are taken into account, the utility will still have the same incentive as it always had--increasing the volumetric sales of energy. Revenue decoupling alleviates this burden by avoiding this cumbersome analysis and simply ensuring a utility recovers its authorized revenues.

Contrary to the opponent's characterization of full revenue decoupling as a mechanism that will cause a windfall of profits for utilities. Full symmetrical decoupling forces utilities to lower rates when they over earn; prioritizes programs performance over sales; and creates less administrative burdens for the states of New Jersey. Additionally, revenue decoupling mechanisms can be designed with additional consumer protections that mitigate potential rate shocks and ensure enough oversight of utility operations. A decoupling collar, or cap, can be set to ensure that upward rate adjustments due to decoupling do not exceed a certain threshold to further protect customers.

Importantly, full revenue decoupling will level the playing field when it comes to numerous clean energy policies currently being pursued by New Jersey. Traditionally, revenue decoupling ensured utilities received their revenue requirements in the face of declining sales. Given New Jersey's ambitious clean energy goals, it is uncertain whether load will grow or decline considering EV deployment and building electrification. However, unlike other forms of cost recovery, decoupling ensures that utilities receive the agreed upon revenue requirement independent of load growth or decline protecting consumers and prioritizing New Jersey's clean energy goals. More simply, full decoupling levels the playing field for diverse clean energy technologies, and prepares utilities for performance-based ratemaking, that rewards utilities for performance in meeting the Quantitative Performance Indicators ("QPIs") identified by the BPU.

Finally, during the stakeholder meetings some stakeholders have repeatedly conflated the concept of customer bills and rates. While it is true that *rates* may increase under a decoupling mechanism, it does not mean that total customer energy costs will increase. Instead, it significantly more likely that if energy efficiency programs are well-designed and implemented, participants in those programs will see bills go down. Additionally, over time decoupling can help defer costly distribution system investments, lowering the cost of the energy system to both

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[9] Id. at 21. ("LRAM as a permanent policy fixture is fraught with flaws. The regulatory burden is great, and the potential to shortchange customers and overcompensate utilities is ever present.").

participants and non-participants alike. Finally, if the state of New Jersey successfully implements the goals of the EMP, it is likely building and vehicle electrification will cause significant load growth. Under this scenario, rates and bills would go down automatically due to the automatic adjustment mechanism.

With the enactment of the CEA, release of the EMP, and New Jersey's joining of the Regional Greenhouse Gas Initiative ("RGGI"), it is clear that the state is seeking to prioritize climate and energy efficiency as the backbone of its energy policy. Further, legislators have recognized that cost recovery mechanisms, such as decoupling should be used to achieve this goal.[10] New Jersey's ratemaking structure should reflect this as well. The states with the most successful programs are those that have instituted full decoupling as it creates a sea change in utility priorities, prioritizing energy efficiency and climate goals.

Therefore, we recommend the use of a Full Symmetrical Decoupling Mechanism.

Incentives/Penalties: % of return (weighted by QPI performance)
We suggest that incentives/penalties be a % of return weighted by QPI performance.

As ACEEE has suggested, amortization can also be used as an incentive because it allows utilities to earn back more than what was originally expended.[11] This incentive can be used to prioritize energy efficiency policy goals in an exchange that utilities are familiar tying higher rates or return to better performance, or similar policy goals.

Illinois has already applied this practice and can serve as a template, the Illinois Public Act 99-0906, provides incentives for energy efficiency performance though through return on equity to electric utilities based on their performance.[12] In this plan, utilities have the option to amortize costs over the average life of benefits and earn a return on these costs.[13] They can earn an extra 2% on their return by exceeding goals or may lose 2% for falling short, and rate increases are capped until 2030 to protect against a utility over performing.

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[10] The Clean Energy Act directs that each utility file a petition with the BPU "for cost recovery of the programs, including any performance incentives or penalties, pursuant to section 13 of P.L. 2007 c.340 (C. 483-98.1). Section 13(b) reads "All electric public utility and gas public utility investment in energy efficiency and conservation programs or Class I renewable energy programs may be eligible for rate treatment approved by the board, including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas." P.L. 2007 c.340 (C. 483-98.1).

[11] ACEEE, Technical Brief Re: Pennsylvania Public Utilities Commission's request for comparison of the Pennsylvania models and practices with those used in other states, February 19, 2019, available at https://aceee.org/sites/default/files/models-comparison-pa.pdf, pg. 12 ("Amortizing the recovery by the utility of the cost of programs over multiple years may also be considered a rate of return incentive in some instances.").

[12] Illinois' Future Energy Jobs Act, P.A. 99-0906 (d)(3)(C), available at http://www.ilga.gov/legislation/publicacts/99/099-0906.htmhttp://www.ilga.gov/legislation/publicacts/99/099-0906.htm.

[13] Jim Zolnierek, Chief of Public Utilities Bureau, Overview of Illinois Public Act 99-0906 PowerPoint, available at https://pubs.naruc.org/pub.cfm?id=E5BC7881-971A-4E55-722D-61A92B8ABFB6.

Carrying Cost on Over/Under Recovery: 2 Year T-Bill

We suggest this as part of this specific hypothetical cost scenario where we are providing best practices that will give New Jersey the right tools to meet and exceed the energy and carbon reduction goals for the state. Please do not take this as our final view point on the issue, see additional group individual comments for further detail on individual group viewpoints.

WACC: Base Rate Case
We suggest that weighted average cost of capital be determined at base rate cases.

Weighted average cost of capital is the return mechanisms for investments utilities make in long term infrastructure projects. Similar to the rational for utilizing a decoupling mechanism, determining weighted average cost of capital for energy efficiency in base rate cases aligns energy efficiency initiatives with utility business model. Additionally, through including and determining return on equity for energy efficiency investment and programs in a base rate case, the Commission and the public have the opportunity for input on the mechanisms and rewards and returns for projects. This will add an additional layer of accountability and the opportunity to align utility business model with public policy.

Therefore, we recommend the Board utilize a cost recovery mechanism which establishes weighted cost of capital through base rate cases.

Rate Cap: No Cap
We suggest that no rate cap mechanism be considered at this point of the process.

A rate cap will artificially limit spending on energy efficiency programs. If the concern is that programs will be too expensive or ineffective, there are other procedures that can be used to establish protections on spending and accountability in program administration and design than a general rate cap. While it could appear to be beneficial to residents and ratepayers, if energy efficiency programs are done successfully, there is potential that such a cap could limit the benefits seen from these programs, as has been the result in Pennsylvania.[14]

The following mechanisms can hold utilities accountable and tie earnings and incentives to consumer satisfaction and engagement.[15]

- Cost-effectiveness Tests.

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[14] Annie Gilleo and James Barrett, Lifting the Cap: Estimating the Economic Impacts of Energy Efficiency Investments in Pennsylvania, April 2019, ACEEE White Paper, Available at https://aceee.org/sites/default/files/pa-jobs-040419.pdf.

[15] *See* Michael Sciortino et al., Energy Efficiency Resource Standards: A Progress Report on State Experience, June 2011, p. 13, American Council for an Energy-Efficient Economy, available at https://www.aceee.org/sites/default/files/publications/researchreports/u112.pdf. ("Rate Impact Caps or budget caps, can prohibit utilities from making the necessary, cost effective, energy efficiency investments…").

- Symmetrical Revenue Decoupling with an up/down adjustment mechanism and rate cap to limit charges on consumer bills.
- Symmetrical Revenue Decoupling with instituted rate cases to check on utility's revenues and spending.
- Caps on performance incentives earnings.
- Scaling incentives and penalties based on consumer savings i.e. .25% return on investment if consumers save % million in electric bills.
- Well established performance incentives and penalties metrics, policy or data based.

This Approach will put New Jersey on the best path forward

Energy efficiency is a low-cost, reliable demand side recourse that provides numerous benefits to the electric system. The New Jersey Board of Public Utilities should align their cost recovery mechanism policy to the "three-legged stool" regulatory approach proposed by the American Council for an Energy-Efficiency Economy (ACEEE) to ensure New Jersey exceeds its energy efficiency goals:

1. Recovery of energy efficiency program direct costs.
2. Removal of the throughput incentive (profits linked to increased energy sales) through full symmetrical decoupling.
3. Creation of earnings opportunities for efficiency investments and performance through rate of return tied to performance.[16]

The approach will insure that New Jersey surpass the energy reduction goals in the Clean Energy Act. While also keeping with the policies and initiatives in the Energy Master Plan and state solar and electric vehicles initiatives.[17]

Sincerely,

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[16] Maggie Molina and Marty Kushler, Policies Matter: Creating a Foundation for an Energy Efficiency Utility of the Future, June 2015, pg.8, available at: https://aceee.org/sites/default/files/policies-matter.pdf.
[17] *Id*.

January 3, 2020

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Submitted via email: EnergyEfficiency@bpu.nj.gov

Re: New Jersey Energy Efficiency Transition Stakeholder Group, Energy Efficiency Technical Meeting II – Cost Recovery 2, Comments on BPU Cost Recovery Scenarios.

Introduction

The Energy Efficiency Alliance of New Jersey ("EEA-NJ") is a trade association dedicated to expanding the market for energy efficiency in the Garden State. Together with its sister organization, the Keystone Energy Efficiency Alliance ("KEEA"), EEA-NJ has more than 60 business members who provide energy efficiency products and services across the state, and support an industry that accounts for more than 30,000 New Jersey jobs. Our membership is large and diverse, with experience designing and implementing a variety of demand side management solutions and energy efficiency programs across the globe. Simply stated, our members understand what works and what does not when it comes to successful demand side reduction programs.

EEA-NJ appreciates the opportunity to engage with the New Jersey Board of Public Utilities ("BPU" or "Board") on program cost recovery under the Clean Energy Act ("CEA"). With these comments, the joint comment submitted with partners across the state, and the individual comments of our member companies and partners, EEA-NJ hopes to provide the BPU with the information required to create a thriving market for energy efficiency in New Jersey.

Clean Energy Act and Cost Recovery

The Clean Energy Act mandates that New Jersey's electric and gas utilities reduce energy usage. Specifically, the CEA requires that each electric utility achieve a minimum 2% reduction in energy usage per year, while each natural gas utility must achieve a minimum .75% reduction per year.[1] Regarding program cost recovery, the CEA clearly states that utilities can recover energy efficiency programs' costs, "including the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules" and receive incentives and penalties tied to their performance in such programs.[2] Furthermore, in the arena of

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[1] The Clean Energy Act, N.J.S.A. §48:3-87.9(a).
[2] The Clean Energy Act, §48:3-87.9(c) ("In establishing quantitative performance indicators, the board shall use a methodology that incorporates weather, economic factors, customer growth, outage-adjusted efficiency factors, and

cost recovery, the New Jersey legislator has identified that alternative cost recovery mechanisms may be used to implement energy efficiency programs, including decoupling.[3]

On December 19, 2019, the BPU provided four cost recovery scenarios and asked for interested parties to provide responses and feedback. EEA-NJ would like to submit the following comments concerning both these four specific scenarios and program cost recovery in general. In addition to the comments provided, EEA-NJ would like to incorporate by reference previous comments submitted.[4]

EEA-NJ Cost Recovery Principles and Best-Case Scenario:

While we provide feedback on the BPU scenarios provided below there are 3 main policies that EEA-NJ believes should guide New Jersey's cost recovery mechanism structure:

1. It should stop utilities from associating profits to sales through utilizing full symmetrical decoupling.
2. It should not utilize a general rate cap on program expenditures as proposed by the BPU as there are other mechanisms to ensure accountability and such an artificial cap can deter efficient investments.
3. It should aim to ensure that utilities have financial incentives aligned with state policy goals through treating investment in energy efficiency similar to investment in grid infrastructure through amortization of investments for the weighted life of the measure with a rate of return tied to performance.

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any other appropriate factors to ensure that the public utilities' incentives or penalties ...are **based upon performance**") (emphasis added).

[3] The Clean Energy Act directs that each utility file a petition with the BPU "for cost recovery of the programs, including any performance incentives or penalties, pursuant to section 13 of P.L. 2007 c.340 (C. 483-98.1)." N.J.S.A. §48:3-87.9(e)(1). Section 13(b) reads "All electric public utility and gas public utility investment in energy efficiency and conservation programs or Class I renewable energy programs may be eligible for rate treatment approved by the board, **including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas**." N.J.S.A. §48.3-98.1(13)(b) (emphasis added).

[4] *See, Energy Efficiency Alliance of New Jersey, In the Matter of the Implementation of P.L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs—Docket No. QO19010040 (Feb 15.)*, available at https://drive.google.com/file/d/1rJj3nQJBvj4Gwk2RHPIOHAuNdP67Zs92/view; *See, Energy Efficiency Alliance of New Jersey Comments on the Draft Energy Master Plan (September 16, 2019), available* https://drive.google.com/file/d/1ArzYJCilTBASThDeGwgBbCefleNxum0X/view; *See also, Energy Efficiency Alliance of New Jersey, October 30, 2019 Energy Efficiency Stakeholder Meeting- Programs (Nov. 2019), available at:* https://drive.google.com/file/d/0B_S_sZFYtn6aZUZQa1ZsbnJNOXRYbF9lcGZZTHl1SGw0Sk5j/view; *See also, Energy Efficiency Alliance of New Jersey, New Jersey Energy Efficiency Stakeholder Group, Energy Efficiency Technical Meeting – Cost Recover, October 31, 2019 (Nov. 14, 2019), available at* https://drive.google.com/file/d/1I6fbyAJh4Kef46JaEiHwIbhPP_eOx6wy/view.

Given these principles an ideal cost recovery scenario would be:

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Full Symmetrical Decoupling
Incentives/Penalties	% of return (Weighted by QPI Performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill
WACC	Base Rate Case
Rate Cap	No Cap

**For comparison purposes EEA-NJ would like to note that this proposal is Scenario 3 with one change concerning the lost revenues recovery mechanism.*

1. Utilize full symmetrical decoupling to stop utilities from tying profits to sales.
For the purposes of clarifying the mechanisms discussed in this category, there are definitions provided below:

Full Symmetrical Decoupling: similar to the setting of a budget, determines a utility's full revenue in a rate base case with adjustment mechanisms to compensate for over or under earnings. To implement this method of decoupling, the Board would take the utility's determined revenue requirement and determine the sales price per-customer class based on expected usage to ensure the utility achieves that revenue. If the utility over or under earns, there is a built-in correction mechanism that will adjust rates up or down depending on projected versus actual sales. States that utilize this mechanism often statutorily mandate rate cases so to ensure a check on utility earnings and spending. Generally, this mechanism means that a utility's profitability will be "determined by how well it operates within that budge" and "[a]ctual sales will not have an impact on the budget."[5]

Limited Decoupling or Lost Revenue Adjustment Mechanisms (LRAMs): separates specified causes of variations in sales that result in decoupling adjustments such as weather or utility-operated energy efficiency programs.[6] These mechanisms only impact a portion of utilities rate, allowing for them to earn a guaranteed return on the decoupled variation in addition to whatever other revenues may come from other energy sales with no cap on earnings. LRAMs fail to address the core financial issues that deter utility participation in energy efficiency programs as revenues are still tied to sales.[7]

Partial Decoupling: insulates a portion of the utility's revenue collections from deviations of actual from expected sales. Any variations result in a partial true-up of the separated portion of utility revenues. Because this mechanism only reconciles a portion of a

[5] Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016, pg. 11, available at: https://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities/. Included as Attachment A.
[6] *Id.* at 12 – 13.
[7] *Id.* at 13.

utility's profits and other profits are still tied to sales, it too fails to address the core financial issue that deter utility participation in energy efficiency programs.[8]

The BPU should avoid mechanisms such as LRAM and Partial Decoupling, as they allow for utilities to have a windfall of profits and fail to align utility financial incentives with state energy efficiency policies. Both LRAMs and Partial Decoupling simply compensate utilities for perceived revenue losses without properly addressing the core issue - the throughput incentive.[9] Additionally, both mechanisms allow the utilities to earn a guaranteed income while also profiting from electricity sales, putting the ratepayers at risk of overpaying the utilities.[10] In addition to being a mere half-measure for cost recovery, LRAM's and partial decoupling are administratively burdensome and technically complex.[11] Under full revenue decoupling, no matter what factors impact sales, the true-up mechanism will ensure that utilities only earn their revenue requirements, no more, no less. However, under an LRAM, the BPU and stakeholders will have to undertake an analysis to determine what portion of sales fluctuations are attributable to energy efficiency rather than other factors such as the economy or weather. Additionally, these studies and methods would be open to a review and appeal process adding delays and additional administrative burdens.

Full symmetrical decoupling forces utilities to lower rates when they over earn unlike partial or limited decoupling mechanisms; prioritizes programs performance over sales; and creates less administrative burdens for the states of New Jersey.[12] The mechanism can include protections for ratepayers that mitigate potential rate shocks and ensure sufficient oversight of utility operations, such as a decoupling cap or mandatory rate case period. A decoupling collar, or cap can be set to ensure that upward rate adjustments due to decoupling do not exceed a certain threshold to further protect customers; while statutorily proscribed rate base cases can provide accountability on utility spending and earning.

With the enactment of the Clean Energy Act and Energy Master Plan, and New Jersey's joining of Regional Greenhouse Gas Initiative, it is clear that the state is seeking to prioritize the environment and energy efficiency its rate structure should reflect this as well. A 2019 ACEEE model comparison found that there was "a strong correlation between states achieving high savings results and those employing revenue decoupling."[13] The study shows that states with the most successful programs are those that have instituted full decoupling as it creates a sea change in utility priorities. In fact, states with both EERS and symmetrical revenue decoupling had an

[8] *Id.* at 13

[9] The throughput incentive is the current cost recovery structure where utilities recover costs through increasing the volumetric sale of energy efficiency.

[10] Annie Gilleo, et al., Valuing Efficiency: A Review of Lost Revenues Adjustment Mechanism, June 2015, American Council for an Energy-Efficient Economy, available at https://aceee.org/sites/default/files/publications/researchreports/u1503.pdf. Included as Attachment C.

[11] *Id.* at 21. ("LRAM as a permanent policy fixture is fraught with flaws. **The regulatory burden is great**, and the potential to shortchange customers and overcompensate utilities is ever present.") (emphasis added).

[12] For a more detailed explanation of the costs and benefits of utilities please see prior comments submitted by the Energy Efficiency Alliance of New Jersey.

[13] American Council for an Energy-Efficient Economy, A Models Comparison in Pennsylvania, February 19, 2019, ACEEE, available at https://aceee.org/topic-brief/models-comparison-pa. Included as Attachment D.

average savings of 1.6% per year while states without decoupling only saved 0.8% per year.[14] Therefore, New Jersey should also institute a symmetrical decoupling mechanism.

2. Does not utilize a general rate cap on program expenditures as proposed by the BPU as there are other mechanisms to ensure accountability and such an artificial cap can deter efficient investments.

For purposes of clarification, rate cap means the use of an overall cap on energy efficiency spending based on a percentage of total customer bill.

A rate cap will artificially limit spending on energy efficiency programs through the downstream impacts it will have on utility program models. Rather than creating portfolios that will hit energy targets, utilities will prioritize abiding by the spending cap, creating an unnecessary constraint in the development of plans.[15] Further, as energy efficiency is implemented, bills should go down for consumers eliminating the need for a rate cap. Finally, there is potential that such a cap could limit the job benefits and other economic benefits seen from these programs, as has been the result in Pennsylvania, where an American Council for an Energy-Efficient Economy study found that removing the spending cap would have saved customers an additional $240 million dollars a year.[16]

Rather than institute a rate cap, the following mechanisms can work to hold utilities accountable and ensure the cost to benefit ratio is beneficial to consumers.[17]

- Cost-effectiveness Tests.
- Symmetrical Revenue Decoupling with an up/down adjustment mechanism and rate cap to limit charges on consumer bills.
- Symmetrical Revenue Decoupling with instituted rate cases to check on utility's revenues and spending.
- Caps on performance incentives earnings.
- Scaling incentives and penalties based on consumer savings i.e. .25% return on investment if consumers save % million in electric bills.
- Well established performance incentives and penalties metrics, policy or data based.

[14] *Id.* at 10.

[15] Annie Gilleo and James Barrett, Lifting the Cap: Estimating the Economic Impacts of Energy Efficiency Investments in Pennsylvania, April 2019, ACEEE White Paper, Available at https://aceee.org/sites/default/files/pa-jobs-040419.pdf. Included as Attachment B.

[16] *Id.*

[17] Michael Sciortino et al., Energy Efficiency Resource Standards: A Progress Report on State Experience, June 2011, p. 13, American Council for an Energy-Efficient Economy, available at https://www.aceee.org/sites/default/files/publications/researchreports/u112.pdf. ("Rate Impact Caps or budget caps, can prohibit utilities from making the necessary, cost effective, energy efficiency investments…").

3. Ensure that utilities have financial incentives aligned with state policy goals through treating investment in energy efficiency similar to investment in grid infrastructure through amortization of investments for the weighted life of the measure with a rate of return tied to performance.

For New Jersey to make the drastic changes in energy consumption needed to meet the goals of the Clean Energy Act, the state needs to enact policies that prioritize efficiency through aligning utility financial goals with state policy goals. One way to do this is to put investment in energy efficiency on equal footing to investment in infrastructure and the grid. For utilities, investment in infrastructure and delivery is encouraged through amortization of these assets which provides financial security and incentives for stockholders. Additionally, money invested by utilities in energy efficiency programs avoids the need for investment in traditional utility assets.[18] Therefore, amortization of investments in energy efficiency, will align utility financial incentives with state policy and reframe energy efficiency for utilities so that they can replace traditional investment in the grid with investment in energy efficiency.[19] Additionally, amortization is the best path forward for consumers as it reduces bill impacts. There is little doubt that the investments needed to meet the goals of the CEA will be expensive and to expense them would place a heavy financial burned on ratepayers. Amortization of energy efficiency will spread out investment costs and rate impacts for customers; allowing for New Jersey to ramp up investment to comply with the mandates of the Clean Energy Act without a rate shock.

As part of this scenario, weighted average cost of capital should be rate based. Similar to the rational for utilizing a decoupling mechanism, determining weighted average cost of capital for energy efficiency in base rate case aligns utility financial incentives with state environmental policies. Additionally, through including and determining return on equity for energy efficiency investment and programs in a base rate case, the BPU and the public have the opportunity for input on the programs, recovery mechanisms, and rewards and penalties. This will add an additional layer of accountability and the opportunity to align the utility business model with public policy.

Finally, penalties and incentives should be tied to return on equity to ensure the best innovation and accountability on energy efficiency investments. Amortization allows utilities to earn back more than what was originally expended on an asset; tying the rate of return through amortization to performance can align utility financial goals with state policies.[20] This incentive can be used to prioritize energy efficiency policy goals in an exchange that utilities are familiar with.

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[18] Dan York et al., Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation, December 2013, American Council for an Energy-Efficient Economy, available at https://aceee.org/research-report/u133.
[19] ACEEE, Aligning Utility Business Models with Energy Efficiency, available at: https://aceee.org/sector/state-policy/toolkit/aligning-utility.
[20] American Council for an Energy-Efficient Economy, A Models Comparison in Pennsylvania, p. 12, February 19, 2019, ACEEE, available at https://aceee.org/topic-brief/models-comparison-pa. Included as Attachment D. ("Amortizing the recovery by the utility of the cost of programs over multiple years may also be considered a rate of return incentive in some instances.").

New Jersey Board of Public Utilities Provided Scenarios and Feedback

Previously Discussed Scenario 1

Asset/Investment Treatment	Expense
Recovery Period	Annual
Lost Revenues	No Decoupling
Incentives/Penalties	% of Savings (Weighted by QPI Performance) / $ for Negative Benefits (Weighted by QPI Performance)
Carrying Cost on Over/Under Recovery	T-Bill
WACC	None
Rate Cap	2% Annual Increase of total customer bill

We strongly disagree with this scenario for the following reasons and have highlighted the factors that cause issues.

1. Utilities would have to expense programs meaning efficiency investments and expenses will not have any financial equity with capital investment, deterring long-term and major investment in energy efficiency projects.
2. No decoupling means that utilities will still aim to grow electrical sales and not prioritize energy efficiency.
3. An artificial cap on spending means that the spending limit and not the policy goals will drive utility investment in energy efficiency.

Previously Discussed Scenario 2

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Full Decoupling
Incentives/Penalties	Fixed Dollar Incentive/Fixed Dollar Penalty (Thresholds related to QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case
Rate Cap	No Cap

We would likely support this scenario. This scenario for the most part follows the principles that we have outlined above and would likely provide successful programs for the state of New Jersey.

New Scenario 3

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Limited Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill
WACC	Base Rate Case
Rate Cap	No Cap

We would likely support this scenario but do not agree with the use of limited decoupling as the best path forward. Please see the section above on why full symmetrical decoupling and not limited decoupling is the best path forward.

New Scenario 4

Asset/Investment Treatment	Amortization
Recovery Period	10 Years
Lost Revenues	No Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case less 200BP
Rate Cap	3% annual increase of total customer bill

We strongly disagree with this scenario for the following reasons and have highlighted the factors that cause issues.

1. No decoupling means that utilities will still aim to generate electrical sales and not prioritize energy efficiency.
2. An artificial cap on spending means that the spending limit and not the policy goals will drive utility investment in energy efficiency.

Sincerely,

Erin Cosgrove

Erin Cosgrove, esq.
Policy Counsel
Energy Efficiency Alliance of New Jersey

Attachment A

RAP® Energy solutions for a changing world

Revenue Regulation and Decoupling:

A Guide to Theory and Application

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RAP® Energy solutions for a changing world

Revenue Regulation and Decoupling:

A Guide to Theory and Application

Second Printing

November 2016

Contents

Preface

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as *decoupling* and the policy issues associated with its use. This includes public utility commissioners and staff, utility management, advocates, and others with a stake in the regulated energy system.

Many utility-sector stakeholders have recognized the conflicts implicit in traditional regulation that compel a utility to encourage energy consumption by its customers, and they have long sought ways to reconcile the utility business model with contradictory public policy objectives. Simply put, under traditional regulation, utilities make more money when they sell more energy. This concept is at odds with explicit public policy objectives that utility and environmental regulators are charged with achieving, including economic efficiency and environmental protection. This *throughput incentive* problem, as it is called, can be solved with decoupling.

Currently, some form of decoupling has been adopted for at least one electric or natural gas utility in 30 states and is under consideration in another 12 states. As a result, a great number of stakeholders are in need, or are going to be in need, of a basic reference guide on how to design and administer a decoupling mechanism. This guide is for them.

More and more, policymakers and regulators are seeing that the conventional utility business model, based on profits that are tied to increasing sales, may not be in the long-run interest of society. Economic and environmental imperatives demand that we reshape our energy portfolios to make greater use of end-use efficiency, demand response, and distributed, clean resources, and to rely less on polluting central utility supplies. Decoupling is a key component of a broader strategy to better align the utility's incentives with societal interests.

While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide is accompanied by a spreadsheet that can be used to demonstrate the impacts of decoupling using different pricing structures or, as the jargon has it, *rate designs*.

This guide was written by Jim Lazar, Frederick Weston, and Wayne Shirley. The RAP review team included Rich Sedano, Riley Allen, Camille Kadoch, and Elizabeth Watson. Editorial and publication assistance was provided by Diane Derby and Camille Kadoch.

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1 Natural Resources Defense Council, *Gas and Electric Decoupling in the U.S.*, April 2010.

1. Introduction

This document explains the fundamentals of *revenue regulation*[2], which is a means for setting a level of revenues that a regulated gas or electric utility will be allowed to collect, and its necessary adjunct *decoupling,* which is an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. Put another way, *decoupling* is the means by which *revenue regulation* is effected. For this reason, the two terms are typically treated as synonyms in regulatory discourse; and, for simplicity's sake, we treat them likewise here.

Revenue regulation does not change the way in which a utility's allowed revenues (i.e., the "revenue requirement") are calculated. A revenue requirement is based on a company's underlying costs of service, and the means for calculating it relies on long-standing methods that need not be recapitulated in detail here. What is innovative about it, however, is how a defined revenue requirement is combined with decoupling to eliminate sales-related variability in revenues, thereby not only eliminating weather and general economic risks facing the company and its customers, but also removing potentially adverse financial consequences flowing from successful investment in end-use energy efficiency.

We begin by laying out the operational theory that underpins decoupling. We then explain the calculations used to apply a decoupling price adjustment. We close the document with several short sections describing some refinements to basic revenue regulation and decoupling.

This printing includes *Decoupling Case Studies: Revenue Regulation Implementation in Six States*, published by RAP in 2014 as a follow-up to this guide.

To assist the reader, an MS Excel spreadsheet is also available that contains sample scenario inputs, analyses, and charts for three forms of revenue regulation, as well as a functioning "decoupling model." It can be downloaded at http://www.raponline.org/wp-content/uploads/2016/05/rap-decouplingmodelspreadsheet-2011-05-17.xlsb.

2 Revenue regulation is often called revenue *cap* regulation. However, when combined with decoupling, the effect is to simply regulate revenue – i.e., there is a corresponding *floor* on revenues in addition to a *cap*.

2. Context for Decoupling

Decoupling is a tool intended to break the link between how much energy a utility delivers and the revenues it collects. Decoupling is used primarily to eliminate incentives that utilities have to increase profits by increasing sales, and the corresponding disincentives that they have to avoid reductions in sales. It is most often considered by regulators, utilities, and energy-sector stakeholders in the context of introducing or expanding energy efficiency efforts; but it should also be noted that, on economic efficiency grounds, it has appeal even in the absence of programmatic energy efficiency.

There are a limited number of things over which utility management has control. Among these are operating costs (including labor) and service quality. Utility management can also influence usage per customer (through promotional programs or conservation programs). Managers have very limited ability to affect customer growth, fuel costs, and weather. Decoupling typically removes the influence on revenues (and profits) of such factors and, by eliminating sales volumes as a factor in profitability, removes any incentive to encourage consumers to increase consumption. This focuses management efforts on cost-control to enhance profits.

In the longer run, this effort constrains future rates and benefits consumers. It also means that energy conservation programs (which reduce customer usage) do not adversely affect profits. A performance incentive system and a customer-service quality mechanism can overlay decoupling to further promote public interest outcomes.

Although it is often viewed as a significant deviation from traditional regulatory practice, decoupling is, in fact, only a slight modification. The two approaches affect behavior in critically different ways, yet the mathematical differences between them are fairly straightforward. Still, it goes without saying that care must be taken in designing and implementing a decoupling regime, and the regulatory process should strive to yield for both utilities and consumers a transparent and fair result.

While traditional regulation gives the utility an incentive to preserve and, better yet, increase sales volumes, it also makes consumer advocates focus on price – after all, that is the ultimate result of traditional regulation. Because decoupling allows prices to change between rate cases, consumer advocates can move the focus of their effort from prices to all cost drivers, including sales volumes – focusing on bills rather than prices.

3. How Traditional Regulation Works

In virtually all contexts, public utilities (including both investor-owned and consumer-owned utilities) have a common fundamental financial structure and a common framework for setting prices.[3] This common framework is what we call the utility's overall *revenue requirement.* Conceptually, the revenue requirement for a utility is the aggregate of all of the operating and other costs incurred to provide service to the public. This includes operating expenses like fuel, labor, and maintenance. It also includes the cost of capital invested to provide service, including both interest on debt and a "fair" return to equity investors. In addition, it includes a depreciation allowance, which represents repayment to banks and investors of their original loans and investments.

In order to determine what price a utility will be allowed to charge, regulators must first compute the total cost of service, that is, the revenue requirement. Regulators then compute the price (or rate) necessary to collect that amount, based on assumed sales levels. In most cases, the regulator relies on data for a specific period, referred to here as the *test period,* and performs some basic calculations.

Here are the two basic formulae used in traditional regulation:

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** TEST PERIOD
Formula 2: **Rate = Revenue Requirement ÷ Units Sold** TEST PERIOD

The rate is normally calculated on a different basis for each customer class, but the principle is the same – the regulator divides the revenue requirement among the customer classes, then designs rates for each class to recover each class's revenue requirement. Table 1 is an example of this calculation, under the simplifying assumption that the entire revenue requirement is collected through a kWh charge.

3 Conditions vary widely from country to country or region to region, and utilities face a number of local and unique challenges. However, for our purposes, we will assume that there is a fundamental financial need for revenues to equal costs – including any externally imposed requirements to fund or secure other expense items (such as required returns to investors, debt coverage ratios in debt covenants, or subsidies to other operations, as is often the case with municipal- or state-run utilities). In this sense, virtually all utilities can be viewed as being quite similar.

3.1 Revenue Requirement

A utility's revenue requirement is the amount of revenue a utility will actually collect, only if it experiences the sales volumes assumed for purposes of price-setting. Furthermore, only if the utility incurs exactly the expenses and operates under precisely the financial conditions that were assumed in the rate case will it earn the rate of return on its rate base (i.e., the allowed investment in facilities providing utility service) that the regulators determined was appropriate. While much of the rate-setting process is meticulous and often arcane, the fundamentals do not change: in theory a utility's revenue requirement should be sufficient to cover its cost of service — no more and no less.

Table 1

Traditional Regulation Example: **Revenue Requirement Calculation**	
Expenses	100,000,000
Net Equity Investment	100,000,000
Allowed Rate of Return	10.00%
Allowed Return	$10,000,000
Taxes (35% tax rate)	$5,384,615
Total Return & Taxes	$15,384,615
Total Revenue Requirement	$115,384,615
Price Calculation	
Revenue Requirement	$115,384,615
Test Year Sales (kWh)	1,000,000,000
Rate Case Price ($/kWh)	$0.1154

3.1.1 Expenses

For purposes of decoupling, expenses come in two varieties: production costs and non-production costs.[4]

3.1.1.1 Production Costs

Production costs are a subset of total power supply costs, and are composed principally of fuel and purchased power expenses with a bit of variable operation and maintenance (O&M) and transmission expenses paid to others included. Production costs as we use the term here are those that vary more or less directly with energy consumption in the short run. The mechanisms approved by regulators generally refer to very specific accounts defined in the utility accounting manuals, including "fuel," "purchased power," and "transmission by others."

4 A utility's expenses are often characterized as "fixed" or "variable. However, for purposes of resource planning and other long-run views, all costs are variable and there is no such thing as a fixed cost. Even on the time scale between rate cases, some non-production costs that are often viewed as fixed (e.g., metering and billing) will, in fact, vary directly with the number of customers served. When designing a decoupling mechanism, it is more appropriate to differentiate between "production" and "non-production," since one purpose of the mechanism is to isolate the costs over which the utility actually has control in the short run (i.e., the period between rate cases).

Production costs for most electric utilities are typically recovered through a flow-through account, with a reconciliation process that fully recovers production costs, or an approximation thereof.[5] This is usually accomplished through a separate fuel and purchased-power rate (fuel adjustment clause, or FAC) on the customer's bill. This may be an "adder" that recovers total production costs, or it may be an up-or-down adjustment that recovers deviations in production costs from the level incorporated in base rates.

In the absence of decoupling, a fully reconciled FAC creates a situation in which any increase in sales results in an increase in profits, and any decrease in sales results in a decrease in profits. This is because even if very high-cost power is used to serve incremental sales, and if 100% of this cost flows through the FAC, the utility receives a "net" addition to income equal to the base rate (retail rate less production costs) for every incremental kilowatt-hour sold.[6] An FAC is therefore a negative influence on the utility's willingness to embrace energy efficiency programs and other actions that reduce utility sales. Decoupling is an important adjunct to an FAC to remove the disincentive that the FAC creates for the utility to pursue societal cost-effectiveness.[7]

Because they vary with production and because they are separately treated already, production costs are not usually included in a decoupling mechanism. If a utility is allowed to include the investment-related portion of costs for purchased power contracts (i.e., it buys power to serve load growth from an independent power producer, and pays a per-kWh rate for the power received), it may be necessary to address this in the structure of the FAC to ensure that double recovery does not occur. This can also be addressed by using a comprehensive power cost adjustment that includes all power supply costs, not just fuel and purchased power. Unless otherwise noted, we assume that production costs are not included in the decoupling mechanism.

5 Many commissions use incentive mechanisms in their fuel and purchased-power mechanisms, to provide utilities with a profit motive to minimize fuel and purchased-power costs and to maximize net off-system sales revenues. For our purposes, these are deemed to fully recover production costs. Some regulators include both fixed and variable power supply costs in their power supply cost recovery mechanism, in which case all of those would be classified as "production" costs and deemed to be fully recovered through the power supply mechanism.

6 Moskovitz, D. (1989, November). *Profits & Progress Through Least-Cost Planning*, p. 4. National Association of Regulatory Utility Commissioners. Retrieved from http://www.raponline.org/knowledge-center/profits-progress-through-least-cost-planning/

7 If a utility does not have an FAC at all, or acquires power from independent power producers on an ongoing basis to meet load growth, the framework for decoupling may need to be slightly different. In those circumstances, revenues from the sale of surplus power or avoided purchased power expense resulting from sales reductions flows to the utility, not to the consumers, through the FAC. In this situation, the definition of "production costs" may need to include both power supply investment-related costs and production-related operating expenses for decoupling to produce equitable results for consumers and investors.

3.1.1.2 Non-Production Costs

Non-production costs include all those that are not production costs — in essence, everything that is related to the delivery of electricity (transmission, distribution, and retail services) to end users. This normally includes all non-production related O&M expenses, including depreciation and interest on debt. In many cases, the base rates also include the debt and equity service (i.e., the interest, return, and depreciation) on power supply investments, in which case the form of the FAC becomes important.

Statistically, a utility's non-production costs do not vary much with consumption in the short run, but are more affected by changes in the numbers of customers served, inflation, productivity, and other factors.[8] Of course, a utility with a large capital expenditure program, such as the deployment of smart grid technologies or significant rebuilds of aging systems, will experience a surge in costs that is unrelated to customer growth. Decoupling does not address this issue, which is better handled in the context of a rate case or infrastructure tracking mechanism.

Non-production costs are usually recovered through a combination of a customer charge,[9] plus one or more volumetric (per kWh, per kW) rates. A utility may face the risk of not recovering some non-production costs if sales decline. Put another way, many of the costs do not vary with sales, so each dollar decline in sales flows straight to — and adversely affects — the bottom line.

3.1.2 Return

For our purposes, the utility's "return" is the same as its net, after-tax profit, or net income for common stock.[10] When computing a revenue requirement for a rate case, this line item is derived by multiplying the utility's net equity investment by its "allowed" rate of return on common equity. We have simplified this return in the illustration, but will address it in more detail in Section 10, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

8 Eto, J., Stoft, S., and Belden, T. (1994, January). *The Theory and Practice of Decoupling Utility Revenues from Sales.* Lawrence Berkeley National Laboratory. Retrieved from http://eetd.lbl.gov/sites/all/files/publications/the-theory-and-practice-of-decoupling-utility-revenues-from-sales.pdf

9 In place of a customer charge, one may also find other monthly fixed charges, such as minimum purchase amounts, access fees, connection fees, or meter fees. For our purposes, these are all the same because they are not based on energy consumption, but, instead, are a function of the number of customers.

10 Regulatory commissions often calculate an "operating income" figure in the process of setting rates; this does not take account of the tax effects on the debt and equity components of the utility capital structure. Net income includes these effects.

11 Shirley, W., Lazar, J. & Weston, F. Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

In a rate case, the return is a static expected value. In between rate cases, *realized* returns are a function of actual revenues, actual investments, and actual expenses, all of which change between rate cases in response to many factors, including sales volumes, inflation, productivity, and many others.

As a share of revenues in a rate case revenue requirement calculation, the return on equity to shareholders may be as small as 5%-10%. As a result, small percentage changes in total non-production revenues (all of which largely affect return and taxes) can generate large percentage changes in net profits.[11]

3.1.3 Taxes

In a rate case, the amount of taxes a utility would pay on its allowed return is added to the revenue requirement.

In between rate cases, taxes buffer the impact on the utility's shareholders of any deviations of realized returns from expected returns. When realized returns rise, some portion is lost to taxes, so shareholders do not garner gains one-for-one with changes in net revenues. Conversely, if revenues fall, so do taxes. As a result, investors do not suffer the entire loss. If the tax rate is 33%, then one third of every increase or decrease in pre-tax profits will be absorbed by taxes.

From a customer perspective, there is no buffering effect from taxes. To the contrary, customers pay all additional revenues and enjoy all savings, dollar for dollar.

Traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales.

3.1.4 Between Rate Cases

With traditional regulation, while the determination of the revenue requirement *at the time of the rate case decision* is meticulous, the utility will almost certainly *never* collect precisely the allowed amount of revenue, experience the associated assumed levels of expenses or unit sales, or achieve the expected profits. The revenue requirement is only used as input to the price determination. Once prices are set, *realized* revenues and profits will be a function of *actual sales and expenses* and will have only a rough relationship with the rate case allowed revenues or returns.

Put another way, traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales. At this point, the rate case formulae no longer hold sway. Instead, two different mathematical realities operate:

Formula 3: **Revenues $_{\text{ACTUAL}}$ = Units Sold Actual X Price**

Formula 4: **Profit $_{\text{ACTUAL}}$ = (Revenues – Expenses – Taxes) $_{\text{ACTUAL}}$l**

These two formulae reveal the methods by which the utility can increase its profits. One approach is to reduce expenses. Providing a heightened incentive to operate efficiently is sound. However, there is a floor below which expenses simply cannot be reduced without adversely affecting the level of service, and to ensure that utilities cut fat, but not bone, some regulators have established service quality indices that penalize utilities that achieve lower-than-expected customer service quality. The easier approach is to increase the Units Sold, as this will increase revenues and therefore profits.[12] This is the heart of the throughput incentive that utilities traditionally face – and this is where decoupling comes in.

3.2 How Decoupling Works

There are a variety of different approaches to decoupling, all of which share a common goal of ensuring the recovery of a defined amount of revenue, independent of changes in sales volumes during that period. Some are computed on a revenue-per-customer basis, while others use an attrition adjustment (typically annual) to set the allowed revenue. Some operate on an annual accrual basis, while others operate on a current basis in each billing cycle. Table 2 categorizes these and provides an example of each approach; a greater discussion of these approaches is contained in the appendix.

Table 2

Decoupling Methodology	Key Elements	Example of Application
Accrual Revenue Per Customer	Allowed revenue computed on an RPC basis; one rate adjustment per year	Utah, Questar
Current Revenue Per Customer	Allowed revenue computed on an RPC basis; rates adjusted each billing cycle to avoid deferrals	Oregon, Northwest Natural Gas Company; DC: Pepco
Accrual Attrition	Allowed revenue determined in periodic general rate cases; changes to this based on specified factors determined in annual attrition reviews; rates adjusted once a year	California, PG&E and SCE Hawaii, Hawaiian Electric
Distribution-Only	Only distribution costs included in the mechanism; all power costs (fixed and variable) recovered outside the decoupling mechanism	Massachusetts, NGrid Maryland, BG&E Washington (PSE, 1990-95)

12 This is because, as noted earlier, the utility faces virtually no changes in its non-production costs as its sales change. This means that marginal increases in sales will have a large and positive impact on the bottom line, just as marginal reductions in sales will have the opposite effect.

3.2.1 In the Rate Case (It's the same)

With decoupling there is no change in the rate case methodology, except perhaps for the migration of some cost items into or out of the production cost recovery mechanism.[13] Initial prices are still set by the regulator, based on a computed revenue requirement.

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** $_{\text{TEST PERIOD}}$
Formula 5: **Price** $_{\text{END OF RATE CASE}}$ **= Revenue Requirement ÷ Units Sold** $_{\text{TEST PERIOD}}$

3.2.2 Between Rate Cases (It's different)

There are two distinct components of decoupling which are embedded in the decoupling formulae: determination of the utility's allowed revenues and determination of the prices necessary to collect those allowed revenues.

With decoupling, the price computed in the rate case is only relevant as a reference or beginning point. In fact, the rate case prices may never actually be charged to customers. Instead, under "current" decoupling (described below), prices can be adjusted immediately, based on actual sales levels, to keep revenues at their allowed level. Rather than holding prices constant between rate cases as traditional regulation would do, decoupling adjusts prices periodically, even as frequently as each billing cycle, to reflect differences between units sold $_{\text{TEST PERIOD}}$ and units sold $_{\text{ACTUAL}}$, as necessary to collect revenues $_{\text{ALLOWED}}$. This is accomplished by applying the following formulae:

Formula 6: **Price** $_{\text{POST RATE CASE}}$ **= Revenues** $_{\text{ALLOWED}}$ **÷ Units Sold** $_{\text{ACTUAL}}$
Formula 7: **Revenues** $_{\text{ACTUAL}}$ **= Revenues** $_{\text{ALLOWED}}$
Formula 4: **Profits** $_{\text{ACTUAL}}$ **= (Revenues – Expenses – Taxes)** $_{\text{ACTUAL}}$

Table 3 gives an example of the calculations.

13 Examples of costs that are sometimes recovered on an actual cost basis include nuclear decommissioning (which rises according to a sinking fund schedule), energy conservation program expenses, and infrastructure trackers for non-revenue-generating refurbishments. Where a utility does not have an FAC or purchases power from independent power producers to meet load growth, it may be necessary to include all power supply costs, fixed and variable, in the definition of "production costs."

There are two distinct actions embedded in the decoupling formulae: determination of the utility's *allowed* revenues and determination of the *prices* necessary to collect those allowed revenues. The former can involve a variety of methods, ranging from simply setting allowed revenues at the amount found in the last rate case to varying revenues over time to reflect non-sales-related influences on costs and revenues, as discussed in Section 5, *Revenue Functions.* The latter is merely the calculation which sets the prices that, given sales levels (i.e., billing determinants), will generate the allowed revenue.

Table 3

Decoupling Example: **Revenue Requirement Calculation**	
Expenses	**$100,000,000**
Net Equity Investment	**$100,000,000**
Allowed Rate of Return	**10.00%**
Allowed Return	**$10,000,000**
Taxes (35% tax rate)	**$15,384,615**
Total Revenue Requirement	**$115,384,615**
Price Calculation	
Revenue Requirement	**$115,384,615**
Actual Sales (kWh)	**990,000,000**
Decoupling Price ($/kWh)	**$0.1166**
Decoupling Adjustment ($/kWh)	**$0.0012**

Put another way, while traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption. This price recalculation is done repeatedly – either with each billing cycle or on some other periodic basis (e.g., annual), through the use of a deferral balancing and reconciliation account.[14]

While traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption.

There are two separate elements in play in the price-setting component of decoupling. The first is that prices are allowed to change between rates, based on deviations in sales from the test period assumptions. The second is the frequency of those changes. We discuss the frequency idea in greater detail in Section 8, *Application of Decoupling: Current vs. Accrual Methods.*

14 There are, however, good reasons to seek to limit the magnitude of deviations from the reference price. For example, many decoupling mechanisms allow a maximum 3% change in prices in any year, deferring larger variations for future treatment by the regulator. Significant variability in price may threaten public acceptance of decoupling and the broader policy objectives it serves. Policymakers should be careful to design decoupling regimes with this consideration in mind.

4 Full, Partial, and Limited Decoupling

We use a specialized vocabulary to differentiate various approaches to decoupling.

4.1 Full Decoupling

Full decoupling can be likened to the setting of a budget.

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation — e.g., increased investment in energy efficiency, weather variations, changes in economic activity — does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues. The focus here is delivering revenue to match the revenue requirement established in the last rate case.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement — i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service — is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[15]

The most common form of full decoupling is revenue-per-customer decoupling, which is more fully explained with other forms of decoupling in the next section. The California approach, wherein a revenue requirement is fixed in a rate case and incremental (or decremental) adjustments to it are determined in periodic "attrition" cases, is also a form of full decoupling. Tracking mechanisms, designed to generate a set amount of revenue to

15 This is the simplest form of full decoupling. As described in the next section, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate-case horizon) costs vary more closely with other causes, primarily changes in the numbers of customers.

cover specific costs (independently of base rates and the underlying cost of service) are not incompatible with full decoupling. They would be reflected in separate tariff surcharges or surcredits.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in energy efficiency or other customer-sited resources, but it does remove the utility's natural antagonism to such resources due to their adverse impact on short-run profits. Assuming that management has a limited ability to influence costs and behavior, this allows concentration of that effort on cost reductions, rather than sales enhancements.

4.2 Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).

One creative application of partial decoupling was the combination conservation incentive/decoupling mechanism for Avista Utilities in Washington. The utility was allowed to recover a percentage of its lost distribution margins from sales declines in proportion to its percentage achievement of a Commission-approved conservation target. If it achieved the full conservation target, it was allowed to recover all of its lost margins, but if it fell short, it was allowed only partial recovery.[16] This proved a powerful incentive to fully achieve the conservation goal.

4.3 Limited Decoupling

Under limited decoupling only specified causes of variations in sales result in decoupling adjustments. For example:

- Only variations due to weather are subject to the true-up (i.e., actual year revenues [sales] are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and

16 Washington Utilities and Transportation Commission, Docket UG-060518, 2007. The recovery was capped at 90%.

revenues from which the utility would not be insulated — that is, all else being equal, energy efficiency would adversely affect the company's bottom line. Weather-only adjustment mechanisms have been implemented for several natural gas distribution companies.

- Lost-margin mechanisms, which recover only the lost distribution margin related to utility-operated energy efficiency programs, have been implemented for several utilities. These generally provide a removal of the disincentive for utilities to operate efficiency programs, but may create perverse incentives for utilities to discourage customer-initiated efficiency measures or improvements in codes and standards that cause sales attrition, because these are not compensated.
- Reduced usage by existing customers may be "decoupled," whereas new customers are not included in the mechanism, on the theory that the utility is more able to influence, through utility programs, the usage of existing customers who were a part of the rate-case determination of a test year revenue requirement.
- Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,
- Some combination of the above.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability is sometimes vigorously debated. But more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What value derives from removing sales as a motivator for utility management? What value derives from creating a revenue function that more accurately collects revenue to match actual costs over time? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation?

Limited decoupling does not fully eliminate the throughput incentive. The utility's revenues (and profits, therefore) are still to some degree dependent on sales. So long as it retains a measure of sales risk, the achievement of public policy goals in end-use efficiency and customer-sited resources, environmental protection, and the least-cost provision of service will be inhibited.[17]

17 "Limited decoupling" is synonymous with "net lost revenue adjustments." "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler-than-expected summer weather, or government-mandated end-use energy investments) not occurred.

5 Revenue Functions

One of the collateral benefits of decoupling is the potential for reducing the frequency of rate cases. In its simplest form, a decoupling mechanism maintains revenues at a constant level between rate cases. However, this would inevitably put increasing downward pressure on earnings due to general net growth in the utility's cost structure as new customers are added and operating expenses are driven by inflation, to the extent these are not offset by depreciation, productivity gains, and, in certain cases, cost decreases.

To avoid this problem, the allowed (or "target") revenue a utility can collect in any post-rate-case period can be adjusted relative to the rate-case revenue requirement. Most decoupling mechanisms currently in effect make use of one or more revenue functions to set allowed revenues between rate cases, and we describe the four standard ones here: (1) adjusting for inflation and productivity; (2) accounting for changes in numbers of customers; (3) dealing with attrition in separate cases; and (4) the application of a "K" factor to modify revenue levels over time. There may be others that are, in particular circumstances, also appropriate.

5.1 Inflation Minus Productivity

Before development of the current array of decoupling options, a number of jurisdictions used what has been called "performance-based regulation" (PBR) — relying on a price-cap methodology, instead of decoupling's revenue-based approach. These plans, first developed for telecommunications providers, often included a price adjuster under which the affected (usually non-production) costs of the utility were assumed to grow through the net effects of inflation (a positive value) and increased productivity (a negative

18 Under normal economic conditions, inflation will be a positive value and productivity a negative value, but there can be circumstances that violate this presumption — an extended period of deflation, for instance. In fact, when Great Britain's state-owned electric transmission and distribution companies were privatized in the late 1980s, their prices were regulated under PBR formulas that included positive productivity adjustments. "[Positive] X (that is, an apparent allowance for annual rates of productivity decreases of X percent) factors were chosen in order to provide the industry with sufficient future cash flow in part to meet projected future investment needs and also to increase the attractiveness of the companies

value).[18] Prices were allowed to grow at the rate of inflation, less productivity, in an effort to track these expected changes in the utility's cost of service. In some cases, other factors (often called "Z" factors) were added to the formulae to represent other explicit or implicit cost drivers. For example, if a union contract had a known inflationary factor, this might be used in lieu of a general inflation index, but only for union labor expenses.

This adjustment is being used in revenue-decoupling regulation, too, to determine a revenue path between rate cases. Rather than applying this adjustment to prices, it is applied to the allowed revenue between rates cases.[19] This approach is used in California, with annual "attrition" cases that consider other changes since the last general rate case, then add (or subtract) these from the revenue requirement determined in the rate case.

With the inflation and productivity factors in hand, the allowed revenue amount can be adjusted periodically. In practice, this adjustment has usually been done through an annual administrative filing and review. In theory, however, there is no practical reason these adjustments could not be made on a current basis, perhaps with each billing cycle.[20] In application, the net growth in revenue requirement is usually spread evenly across all customers and all customer classes.

The inflation-minus-productivity approach does not remove all uncertainty from price changes, because the actual inflation rate used to derive allowed revenues (and, therefore, reference prices) will vary over time.

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to the investment community during their upcoming public auction. The initial regulatory timeframe was set at the fiscal year 1990/1995 time period." See http://training.itcilo.it/actrav_cdrom1/english/global/frame/elect2.htm. (Note that this adjustment is actually referred to as "negative productivity," since it indicates a reduction, rather than an increase, in productivity. Mathematically, it's denoted as the negative of a negative, and so for simplicity's sake we've described it as positive here.)

19 Under this approach, a government-published (or other accepted "third party" source), broad-based inflation index is used. The productivity factor, which serves to offset inflation, is also an administratively determined or, in some cases, a stakeholder agreed-upon value. It should not, however, be calculated as a function of the particular company's own productivity achievements. Doing so would reward a poorly performing company with an overall revenue adjustment (inflation-minus-productivity factor) that is too high (and which does not give it strong enough incentives to control costs) and would punish a highly performing company with a factor that reduces the gains it would otherwise achieve, in effect holding it to a more stringent standard than other companies face.

20 See also *Current vs. Accrual Methods*, below, for more on the implications of using *accrual* methodologies for decoupling versus using a *current* system. It goes without saying, of course, that price changes of this sort can only be effected through a simple, regular ministerial process, if the adjustment factors on which they are based are transparent, unambiguous, and factual in nature (e.g., customer count). If, however, the adjustment is driven by changes that are within management's discretionary — say, capital budget — then a more detailed review may be required to assure that prudent decisions are underlying the revenue adjustments.

5.2 Revenue-per-Customer (RPC) Decoupling

As noted earlier, analysis has shown that, in the time between rate cases, changes in a utility's underlying costs vary more directly with changes in the number of customers served than they do with other factors such as sales, although the correlation on a total expense basis to any of these is relatively weak. When examining only non-production costs, however, the correlations are much stronger, especially for the number of customers.

In 2001, we previously studied the relationships between drivers such as system peak, total energy, and number of customers to investments in distribution facilities.[21]

The data indicate that customer growth is closely correlated to growth of non-production costs.

RAP prepared studies for correlations between investments in transformers and substations versus lines and feeders as they relate to growth in customers served, system peak, and total energy sales. The data indicate that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. These data support using the number of customers served as the driver for computing allowed revenues between rate cases, particularly in areas where customer growth has been relatively stable and is expected to continue. The revenue-per-customer, or RPC method, may not be appropriate in areas with stagnant economies or volatile spurts of growth, or where new customers are significantly different in usage patterns than existing customers, but in these situations, the attrition method may still work well.

The RPC value is derived through an added "last" step in the rate case determination. It is computed by taking the test period revenues associated with each volumetric price charged, and dividing that value by the end-of-test period number of customers who are charged that volumetric price. This calculation must be made for each rate class, for each volumetric price, and for each applicable billing period (most likely a billing cycle):

Formula 8: **Revenue per Customer $_{\text{TEST PERIOD}}$ =**

$$\textbf{Revenue Requirement}_{\text{TEST PERIOD}} \div \textbf{No. of Customers}_{\text{TEST PERIOD}}$$

With this revenue-per-customer number, allowed revenues can be adjusted periodically to reflect changes in numbers of customers. In any

21 Shirley, W. (2001, September). *Distribution System Cost Methodologies for Distributed Generation.* Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/distribution-system-cost-methodologies-for-distributed-generation. Also see accompanying appendices at http://www.raponline.org/knowledge-center/distribution-system-cost-methodologies-for-distributed-generation-volume-ii-appendices

Table 4

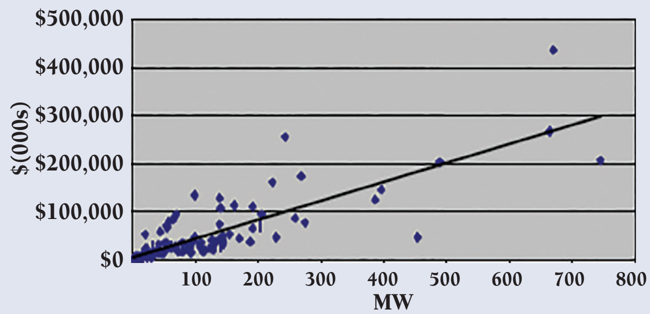
Lines & Feeders

Growth in Lines & Feeders Plant Investment vs. Growth in System Peak

(Five-Year Adjusted Average, 1995-1999)

Statistical Summary

Standard Deviation	$2,129,439
Average	$608,215
Correlation	0.80

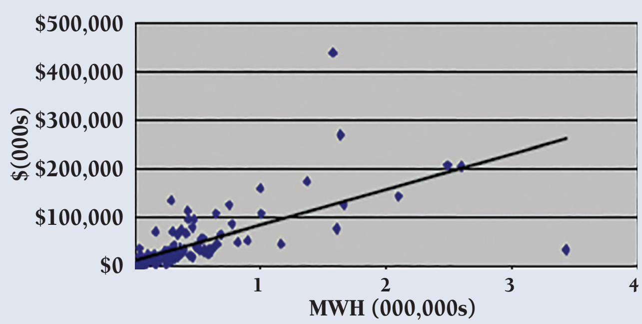


Growth in Lines & Feeders Plant Investment vs. Growth in System Energy

(Five-Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation	$606
Average	$74
Correlation	0.53

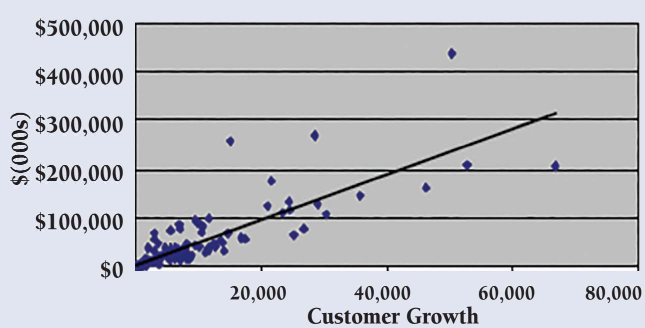


Growth in Lines & Feeders Plant Investment vs. Growth in Customers

(Five-Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation	$13,191
Average	$4,551
Correlation	0.82



post-rate-case period, the allowed revenues for energy and demand charges are calculated by multiplying the actual number of customers served by the RPC value for the corresponding billing period. The decoupling adjustment is then calculated in the manner detailed in the earlier sections.

Formula 9: **Revenues $_{ALLOWED}$ = Revenue per Customer $_{TEST\ PERIOD}$ X No. of Customers $_{ACTUAL}$**

Formula 10: **Price $_{ACTUAL}$ = Revenues $_{ALLOWED}$ ÷ Units Sold $_{ACTUAL}$**

The table below demonstrates the RPC calculations for three billing periods for a sample small commercial rate class. In this example, the billing periods are assumed to be monthly. Note that the revenues per customer are different in each month, because of the seasonality of consumption in the test period.[22]

By calculating the energy and demand revenues per customer for each

Table 5

Deriving the Revenue per Customer Values

Small Commercial Class Example
Test Period Values

Billing Period	**1**	**2**	**3**
Number of Test Period Customers	142,591	142,769	142,947
Customer Charge	$25.00	$25.00	$25.00
Total Customer Charge Revenues	$3,564,775	$3,569,225	$3,573,675
Energy Revenue per Customer			
Energy Sales (kWh)	181,238,883	189,304,436	170,240,013
Rate Case Price	$0.165	$0.165	$0.165
Total Energy Sales Revenues	$29,904,416	$31,235,232	$28,089,602
Energy Revenue per Customer	$209.72	$218.78	$196.50
Demand Revenue per Customer			
Demand Sales (kW)	1,189,355	1,165,396	1,148,975
Rate Case Price	$4.4600	$4.4600	$4.4600
Total Demand Sales Revenues	$5,304,523	$5,197,667	$5,124,429
Demand Revenue per Customer	$37.20	$36.41	$35.85

22 Most utilities typically have 22 or 23 billing cycles per month. For simplicity, we have assumed here that all customers in a month are billed in the same billing cycle (one per month). In the future, with new "smart" metering and communication platforms, a single billing cycle per month, for all customers, may be possible.

billing period, normal seasonal variations in consumption are automatically captured. This causes revenue collection to match the underlying seasonal consumption patterns of the customers.

Some decoupling schemes exclude very large industrial customers. Because the rates for these customers are often determined by contractual requirements and specified payments designed to cover utility non-production costs, there may be little or no utility throughput incentive opportunity relating to these customers anyway. Also, in many utilities, this class of customers may consist of only a small number of large and unique (in load-shape terms) customers, so that a "class" approach is not apt.

In cases in which new customers (that is, those who joined the system during the term of the decoupling plan) have significantly different consumption patterns (and, therefore, revenue contributions to the utility) than existing customers, regulators may want to modify the decoupling formula to account for the difference. This can be accomplished by using different RPC values for new customers and existing customers. The nature of this issue and methodologies for addressing it are discussed in Section 6, *Application of RPC Decoupling: New vs. Existing Customers.*

5.3 Attrition Adjustment Decoupling

Some jurisdictions take a different approach to decoupling. They set base rates in a periodic major rate case, then conduct annual abbreviated reviews to determine whether there are particular changes in costs that merit a change in rates. In such instances, the regulators adjust rate base and operating expenses only for known and measurable changes to utility costs and revenues since the rate case, and adjust for them through a small increment or decrement to the base rates (called "attrition adjustments"). The regulators normally do not consider more controversial issues such as new power plant additions or the creation of new classes of customers, which are reserved for general rate cases.

In attrition decoupling, the utility's allowed revenue requirement is the amount allowed in the first year after the rate case, plus the addition (or reduction) that results from the attrition review. Every few years, a new general rate case is convened to re-establish a cost-based revenue requirement considering all factors.

5.4 K Factor

The K factor is an adjustment used to increase or decrease overall growth in revenues between rate cases.

In its simplest application, the K factor can be used in lieu of either the inflation-minus-productivity method or the RPC method; it could be, for example, a specified percentage per year. Although one could vary the K factor itself over time, in this context the most likely application would simply set an annual between-rate-case growth rate for revenues, resulting in a steady change (probably an increase) in year-to-year allowed revenues for each period between rate cases. Such an approach has a high degree of certainty, but runs the risk of being disassociated from, and therefore out of sync with, measurable drivers of a utility's cost of service. All of the data used in a rate case change over time, and the elements making up the K factor are no different. The K factor therefore may become obsolete within a few years, providing another reason why periodic general rate cases should be required by regulators under decoupling (and, arguably, under traditional regulation as well).

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases.

An alternative approach is to use the K factor as an adjustment to the RPC allowed revenue determination. Here, the K factor growth rate (positive or negative) would be applied to the RPC values, rather than to the allowed revenue value itself. This approach would be useful when an additional revenue requirement is anticipated due to identifiable increases in revenues from capital expenditures or operating expenses, or because of some underlying trend in the RPC values. An example would be a utility with a distribution system upgrade program driven by reliability concerns, where the investment is not generating new revenue. It may also be used as an incentive for the utility to make specific productivity gains, in which case the K factor would be a negative value causing revenues to be slightly lower than they otherwise would have been.

In any case, allowed revenues would still be primarily driven by the number of customers served, but the revenue total would be driven up or down by the K factor adjustment.

Formula 11: **Revenue Per Customer $_{\text{ALLOWED}}$ = Revenue Per Customer $_{\text{TEST PERIOD}}$ * K**

Formula 12: **Revenues $_{\text{ALLOWED}}$ = Revenue Per Customer $_{\text{ALLOWED}}$ X No. of Customers $_{\text{ACTUAL}}$**

Formula 13: **Price $_{\text{ACTUAL}}$ = Revenues $_{\text{ALLOWED}}$ ÷ Units Sold $_{\text{ACTUAL}}$**

5.5 Need for Periodic Rate Cases

It is useful to have periodic rate cases in which all costs, expenses, investments, programs, policies, and tariff designs can be examined. Many regulators have required general rate cases every three to five years as part of decoupling (or set expiration dates for the decoupling mechanism). Another approach would be a built-in decline in the allowed revenue (or RPC) after three to five years. This would allow the utility to avoid a new general rate case (in which all of the utility's costs would be examined), but only if it reduced customer bills. This leaves the utility with the option to continue to retain a portion of expense containment savings motivated by decoupling (see Formula 4) without a rate case, if it can reduce costs sufficiently to give consumers a measurable benefit.

5.6 Judging the Success of a Revenue Function

One of the shortcomings of traditional utility pricing approaches is that a utility's actual revenue collection can be significantly higher or lower than its actual cost of providing service. The different revenue functions that can be applied with decoupling offer means of keeping the utility's revenue collections much closer to its actual cost of service over time. This should result in smaller rate case revenue deficiencies or excesses, lessening their associated potential for "rate shock."

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases. Indeed, the theoretically ideal result, by this standard, would be to have a zero revenue deficiency or excess in the next rate case and at most points in between, meaning that rates had tracked costs perfectly over time.

Of course, when judging the revenue function on this basis, one should disregard special circumstances that may cause a significant revenue deficiency, such as large additions to the utility's plant-in-service accounts (e.g., the addition of a new transmission line, the installation of an expensive new management information system, or the deployment of smart-grid advanced metering infrastructure).

6 Application of RPC Decoupling: New vs. Existing Customers

As much as half of the change in average usage per customer over time may be explained by differences between existing and new customers. Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies.

New customers may be significantly different from existing customers. For example, new building codes and appliance standards may mean that new customers are fundamentally more efficient. Typical new homes may be larger or smaller than the average of existing homes (or may reflect a different mix of single-family and multi-family construction). If urban areas are becoming more densely populated, it may mean that new customers are closer together, and thus there is a smaller distribution system investment per customer. If line extension policies require new customers to pay a larger share of distribution system expansion costs than existing customers did, the investment added to the utility rate base per customer may be smaller for new customers. If the regulator is concerned that there may be meaningful differences between new and existing customers, it can require the utility to perform a detailed analysis of usage characteristics (quantity, seasonality, time-of-day) for each cohort of customers connected to the system.

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small crosssubsidies

As illustrated in Table 6, new customers, on average, use 450 kWh in a billing period, but the rate case-derived RPC for existing customers is 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed or used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, whereas the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6

Single RPC for Existing and New Customers			
	Existing Customers	**New Customers**	**Total**
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$50.00	
Allowed Revenues	$10,000,000	$500,000	$10,500,000
Average Unit Sales	500	450	
Decoupled Price	$0.100478	$0.100478	
Collected Revenues	$10,047,847	$452,153	$10,500,000
Average Customer Contribution	$50.24	$45.22	$50.00

To correct for this, a separate RPC value can be calculated for new customers — in our example, the amount for them would be $45.00. As shown in Table 7, the RPC allowed revenues would not be increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.76. Accounting for these differences affects the *allowed* revenue to assure no over- or under-recovery, while differences in bills for these two types of customers are automatically reflected in their respective units of consumption applied to the decoupled price.

Table 7

Separate RPC for Existing and New Customers			
	Existing Customers	**New Customers**	**Total**
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$45.00	
Allowed Revenues	$10,000,000	$450,000	$10,450,000
Average Unit Sales	500	450	
Decoupled Price	$0.100000	$0.100000	
Collected Revenues	$10,000,000	$450,000	$10,450,000
Average Customer Contribution	$50.00	$45.00	$49.76

7 Rate Design Issues Associated With Decoupling

As it does with respect to increased investment in end-use energy efficiency itself, decoupling should also remove traditional utility objections to electric and natural gas rate designs that encourage conservation, voluntary curtailment, and peak load management. For example, assuming average usage of 500 kWh/month, the two following rate designs produce the same amount of revenue, but the volumetric rate provides a much stronger price signal for consumers to pursue energy efficiency:

Table 8

High vs. Low Customer Charges

Rate Element	High Customer	Low Customer
Customer Charge	$25.00	$5.00
Usage Charge	$0.10	$0.14
Total Bill for 500 kWh average usage	$75.00	$75.00

Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. In addition, those with fully reconciled fuel and purchased-power adjustment mechanisms completely recover the high cost of augmenting power supply during peak periods when expensive power resources are used, so even increased peak-period sales generate a distribution sales margin.[23] A reduction of throughput will likely reduce

23 See Subsection 3.1.1.1 above, and Moskovitz, *Profits and Progress Through Least Cost Planning*, pp. 3-5. Fuel adjustment mechanisms are the antithesis of energy efficiency mechanisms. They guarantee that any additional sale, no matter how expensive to serve, adds to profit, and any foregone sale diminishes profitability. This is because the clauses ensure that the marginal fuel or purchase cost of incremental sales will be fully recovered, so that the non-production cost component of base rates will always contribute to the bottom line (by either increasing profits or reducing losses).

revenues at a greater rate than it will produce savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

Currently, the best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric (PG&E), typical of those of all gas utilities and at least the investor-owned electric utilities in the state, are shown in Table 9. Both the gas and electric rates are set up with a "baseline" allocation, which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service. If usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

Table 9

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Baseline Quantities	Excess Quantities
Minimum Monthly Charge	~$3.00	
Base Rate per Therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.01770	$0.17700
Low-income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

Table 10

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Low Income	All Other Customers
Minimum Monthly Charge	~$3.50	~$4.45
Baseline Quantities	$0.83160	$0.11559
101%-130% of Baseline	$0.09563	$0.13142
131%-200% of Baseline	$0.09563	$0.22580
201%-300% of Baseline	$0.09563	$0.31304
Over 300% of Baseline	$0.09563	$0.35876

7.1 Revenue Stability Is Important to Utilities

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for PG&E (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

The revenue stability needs of the company can conflict with principles of cost-causation as they relate to pricing. Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers. Cost-of-service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage, and liquefied natural gas (LNG) facilities) and those capacity costs are allocated exclusively to increased use in winter and summer months, the cost to consumers of incremental usage is dramatically higher than the cost of base usage.

A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage for which that capacity exists. Although this is arguably fair, doing so can result in serious revenue stability problems for the utility. Decoupling is one way to provide revenue stability for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

7.2 Bill Stability Is Important to Consumers

Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. In a hot summer or cold winter, consumer bills can soar as their end-block usage increases. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause. When their usage (as a group) increases, the non-production component of the rate design automatically declines, so that they pay the allowed revenue requirement (and no more) for distribution services. Conversely, when weather is unusually mild, and customer usage declines, they would pay slightly more per unit for distribution services, again ensuring the utility receives its allowed revenue. This effect is most pronounced when decoupling is applied on a current, rather than an accrual basis, as discussed later.

7.3 Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based utility regulation, and he identified eight principles, some of which are in tension with each other, to guide the design of utility prices. That tension is demonstrated in particular by three of those principles — that rates should yield the total revenue requirement, they should provide predictable and stable revenues, and they should be set so as to promote economically efficient consumption.[24] In certain instances, more economically efficient pricing structures could lead to customer behavior that results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include:

7.3.1 Zero, Minimal, or "Disappearing" Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental and supply costs that may already be trending upward.[25] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage being offered and

24 Bonbright, James C., *Principles of Public Utility Rates.* Columbia University Press, New York, 1961, p. 291.

25 For electric utilities depending on coal for the majority of their supply, valuing CO_2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 to $100/tonne) would add up to $.03/kWh to $.10/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

The California utilities, under decoupling, have retained zero or minimal customer charges. In several cases, such as with the PG&E rates discussed earlier in Section 7, it comes in the form of a "disappearing minimum bill," in which customers with zero consumption pay a minimum amount, but once usage passes 100 kWh or so (and 99% of consumption is by customers exceeding this minimum), they pay only for the energy used. In December 2008, the Public Service Commission of Wisconsin approved a settlement of the parties that, among other things, created a decoupling mechanism for Wisconsin Public Service Corporation and, at the same time, reduced the level of fixed customer charges.[26]

7.3.2 Inverted Rate Blocks

Inverted block rates, of the type shown earlier for PG&E, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. Second, they recognize that upper-block usage (mostly for space conditioning) is characterized by high seasonality, usage concentrated during the peak hours, and low load-factor end-uses, all of which are more expensive to serve than other end-uses. Inverted block rates therefore properly collect the appropriate costs from these infrequent but expensive end uses. They also serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

7.3.3 Seasonally Differentiated Rates

Seasonal rates are typically imposed in service territories whose utilities experience significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

26 Docket 6690-UR-119, *Application of the Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Order of December 30, 2008.

7.3.4 Time-of-Use Rates

Rates that collect much higher amounts during the on-peak hours can convey to consumers that usage during those hours puts the entire system under stress and causes investment in new peaking capacity. However, peak-hour consumption is highly weather-sensitive, so time-of-use (TOU) rates make utility revenues more weather-sensitive, just like inverted block rates. Decoupling removes the revenue stability risk associated with TOU rates, allowing the utility to have efficient prices and still be assured of recovering non-production costs in years when weather is mild.

7.4 Summary: Rate Design Issues

A hypothetically "correct" rate design for an electric and gas utility can consist of a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count) and an inverted block rate structure based on the load factors of typical end-uses. The rates shown for PG&E in California are designed along these lines.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest costs of service.

Taking a hypothetical electric utility with typical meter reading and billing costs, capacity costs of $15/kW per month, and energy costs of $.05/kWh produces the following cost-based rate design:

Table 11

Cost-based Rate Design – Hypothetical Rates

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$0.03	$0.05	$0.08
Next 400 kWh Water Heat	40%	$0.05	$0.05	$0.10
Over 800 kWh Space Conditioning	20%	$0.10	$0.05	$0.15

Establishing theoretically defensible rate designs such as those used by PG&E provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely (or unable) to respond to the incremental cost-based prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing all to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section 8 of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

8 Application of Decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased-power adjustment clause (FAC) for electric utilities and the purchased gas adjustment (PGA) clause for gas utilities. In both of these cases, utilities compute the actual costs for these items, and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs, and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections, and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

The variations in rates and bills caused by decoupling mechanisms are typically very small compared with those caused by FAC and PGA mechanisms. While decoupling adjustments tend to deal with variations in usage of a few percent, the price of natural gas can change by 50% or more over the year after a general rate case. Further, as described earlier, decoupling tends to moderate billing variations, whereas the FAC and PGA mechanism tend to magnify bill variations, because the cost of gas tends to rise in cold winters when demand is highest, and the cost of power tends to rise in the summer with cooling-related demands.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result may be a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility, during a period when the customer is otherwise accruing credits for the following year.

Unlike commodity adjustment clauses, however, there are no forecasting components needed in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. To calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. To calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers), and then divide that number by Actual Unit Sales. In either case, all of the information needed to make the calculation is known at the time that customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current rather than an accrual basis. This also means there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test-year normalized results, except to calculate a daily or monthly (or more likely a billing cycle) RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle,[27] or it can be built up from daily information.[28]

27 For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

28 For more information on this point, see section 3.1.1.2 Non-Production Costs.

9 Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors that prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or limited decoupling, and some forms of partial decoupling, will have a direct impact on the magnitude of these risks.

For the most part, full decoupling will eliminate these risks completely. Limited decoupling partially eliminates these risks. Partial decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

9.1 Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a fair rate of return — the utility's profits). Because most of the revenues are normally collected through volumetric prices, based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[29]

As noted earlier, the basic pricing formula under traditional regulation is:

Formula 13: **Price = Revenue Requirement ÷ Units of Consumption**

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumption remain unchanged, the prices set in a rate case will generate revenues equal to the

29 By "right," we mean consistent with the cost of service methodology.

utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery, and customers from over-payment of the utility's cost of service — because there should be an equal chance of having weather that is more extreme or milder than normal.

With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers which is unrelated to what the utility needs to recover and what customers ought to pay.

In reality, this is hard to accomplish, because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices that are "right" and the weather normalization method used was accurate, the actual revenues collected by the utility and paid by the customers will be a function of the actual units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

***Formula 3:* Actual Revenues = Price * Actual Units of Consumption**

With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills.

To the extent that the utility's costs to provide service due to the weather-related increases or decreases in sales do not change enough to fully offset the revenue change, then the utility will either over- or under-recover its costs. With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers that is unrelated to the amount that the utility needs to recover and that customers ought to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

9.2 The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's non-production revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

***Formula 6:* Price = Allowed Revenue ÷ Actual Units of Consumption**

As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With full decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the allowed revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under partial decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment falls short of recovering the indicated price adjustment, both weather and economic risks are placed upon the utility and its customers.

Under limited decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved the existing burden of weather risk in a decoupled environment by weather-normalizing actual unit sales before computing the new price under limited decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed later in *Other Revenue Stabilization Measures,* are one example of this type of limited decoupling. This has the effect of preserving all of the risks, including weather and economic risks, customers and the utility bear under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

10 Earnings Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. They can also be volatile because of the way weather and other factors influence costs in the short run, without corresponding short-run impacts on revenue (such as a drought has on a hydro-dependent utility). As a result of this volatility, utilities typically retain a relatively higher level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher-risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors, and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer- or utility-financed conservation, self-curtailment due to price elasticity). This in turn lowers the financial risk for the utility, and that is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio.

Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place. However, for this to be justified, the investors must have confidence that the decoupling mechanism will remain in effect for many years; a typical three-year approval period may not provide that confidence.

10.1 Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased-gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, whereas the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically integrated utilities with some risk mitigation measures are in between.[30]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. This approach recognizes that a utility with more stable earnings does not require as much equity in its capital structure, because there is less likelihood of the utility depleting its retained earnings.

Table 12 summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Table 12

Quantification of Savings from Capital Structure Shift

Element	Allowed Return	Ratio w/o Decoupling	Ratio with Decoupling
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement ($ millions)		$104.80	$101.30
Difference			-$3.50

30 See Standard and Poor's *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004. See also Moody's Investor Services, *Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings*, 2006, and Standard and Poor's, *Industry Report Card: U.S. Electric Utilities Well Positioned For 2011 Challenges*, December 10, 2010.

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact — but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

Cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

A utility could adapt its actual capital structure to reflect this change, either by issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the risk reduction afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first.

10.2 Some Impacts May Not Be Immediate, Others Can Be

If rating agencies perceive that a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does not change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, and that earnings are more stable; and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional ratemaking process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years, or as much as a decade; and the cost savings will phase in very slowly as new bonds are issued.

10.3 Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the ratemaking process, with the risk that utilities then become resistant to implementation of decoupling. Utilities have pointed to rate cases in other jurisdictions, where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors and that that value will (eventually) be revealed in some way in the market — through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the theory, however, utilities may tend to view a reduction in the return on equity as a penalty associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides — that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating, rather than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.[31]

31 One recent paper concluded that decoupling did not result in a decrease in the cost of equity capital in the short run. The study focused on only one approach to measure the cost of capital, the discounted cash flow method. It did not consider the reduction in systematic risk (the change in earnings relative to the change in the overall market earnings in the same period) that is measured by the Capital Asset Pricing Model. Decoupling will reduce systematic risk (reducing earnings volatility due to economic cycles) because sales variations in business cycles do not affect earnings under decoupling. The study also did not attempt

10.4 Consumer-Owned Utilities

Consumer-owned utilities (COUs) do not pay cash dividends, but they do need to maintain a sound bond rating to support future investments. The rating agencies look at the TIER (times interest earned ratio) of COUs.[32] Typical bond covenants for COUs obligate the utility to maintain its TIER above a minimum defined level, so they might be required to raise rates if they suffered severe earnings attrition (from any cause).

A loss of revenue due to conservation, weather, or other factors can impair the TIER, and therefore the borrowing capacity of a COU. A decoupling mechanism will provide the same stability of earnings for a COU as for an investor-owned utility (IOU). However, there is a smaller body of research on whether decoupling will actually have a meaningful effect on the borrowing costs of COUs, assuming that their TIER remains within a range in which they are able to borrow.

Without decoupling, COUs tend to set rates at levels that provide 75%-90% assurance that the TIER will remain at an acceptable level. It is clear that a decoupling mechanism will ensure that the TIER remains in an acceptable range, and that the COU will be able to borrow. A decoupling mechanism may thus allow a COU to set rates at a slightly lower level, without fear that a variation in weather or sales will cause it to fall to a level that would trigger a larger rate adjustment.

10.5 Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar, as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline), the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

Even so, in practical application, it is simpler to impose a cap on the variability in prices than in earnings, because the calculation of earnings for regulatory purposes can be significantly different than earnings reporting under generally accepted accounting principles and may invite disputes over methodology.

to measure the change in probability that a utility would exhaust its ability to pay dividends from cash earnings, which is reduced if the utility is protected from variations in earnings driven by weather and economic cycles. These are factors that lead RAP to believe that adjusting the capital structure is more appropriate than adjusting the allowed return on equity when decoupling is implemented on a permanent basis. See Brattle Group, *The Impact of Decoupling on the Cost of Capital,* March, 2011.

32 TIER is a measure of the extent of which earnings are available to meet interest payments. Mathematically it is defined by this formula: TIER = (net income + interest) / (interest).

11 Other Revenue Stabilization Measures, and How They Relate to Decoupling

There are a number of other revenue stabilization measures used by regulatory commissions, some of which are proposed as possible alternatives to decoupling. Some of these provide nearly the same benefits to utility shareholders as decoupling, but all of them fall short of the full range of benefits that revenue decoupling provides, particularly those for consumers and the environment. We discuss several of these below, comparing the consumer impacts and societal benefits to those of decoupling.

11.1 Lost Margin Recovery Mechanisms

A lost margin mechanism provides recovery to the utility for distribution margin that is lost when customers participate in the utility-sponsored energy efficiency programs. The benefit is that the utility resistance to offering such programs is addressed. One side effect is creation of a bias in favor of utility-funded programs to the exclusion of codes, standards, and other lower-cost means to achieve savings. In one experience, a utility was simultaneously offering incentives for participation in its programs, while conducting a political campaign against other types of energy efficiency marketing, to ensure that any lost margins were recovered.

11.2 Weather-Only Normalization

Typically the largest rate adjustments under decoupling are weather-induced. Many natural gas utilities have weather normalization clauses, in which small surcharges are imposed during periods of mild weather, and small surcredits during severe weather. A weather-only adjustment does not address lost sales due to either programmatic energy efficiency on consumer-funded energy efficiency, and therefore does not address one of the principal objectives of decoupling, which is to eliminate utility disincentives for energy efficiency.

11.3 Straight Fixed/Variable Rate Design (SFV)

SFV is an approach to rate design in which all utility fixed costs are recovered in a fixed monthly charge, with only variable costs included in the per-therm or per-kWh rate. The definition of "fixed" costs varies from a strict accounting measure (interest and depreciation) to a broad measure that includes the return on equity, taxes, and labor expenses, but the principle is the same: customers do not pay for utility service on a primarily volumetric basis.

SFV is attractive due to simplicity, but has numerous adverse side effects. These include:

- Energy prices are set far below long-run marginal cost, leading to uneconomic usage;
- Small users, particularly seniors and apartment dwellers, pay much higher electric and gas bills;
- Consumer investment in energy efficiency is discouraged, since the bill savings are small;
- A mismatch occurs between the cost-responsibility and cost-collection for seldom-used peaking facilities (for which the costs should be recovered in incremental usage block rates).

Some studies have estimated that SFV pricing can cause usage to go up 10% or more, enough to offset much or all of the benefit of energy efficiency programs.[33]

11.4 Fuel and Purchased Energy Adjustment Mechanisms

Fuel adjustment clauses (FACs) and purchased gas adjustment (PGAs) mechanisms are used by nearly all gas utilities, and by most electric utilities, to recover variable costs of fuel and purchased energy. They evolved during the first and second oil embargoes in 1973 and 1977, and have become nearly ubiquitous. The benefit of these is that utilities are assured of recovery of a very large set of costs over which they have little control. The side effect is that an FAC or PGA ensures that ANY incremental sale is profitable, since ALL of the increased variable cost is covered, and the incremental sales margin results in incremental profit.

33 Lazar, J., Allen, R. & Schwartz, L. (2011, April). *Pricing Do's and Don'ts.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/pricing-dos-and-donts-designing-retail-rates-as-if-efficiency-counts

FACs and PGAs are therefore of great concern when trying to design a regulatory framework that encourages utility support of energy efficiency.[34] A properly designed decoupling mechanism can overcome this effect by assuring that only the allowed level of non-fuel or non-power revenues are received if utility sales increase.

11.5 Independent Third-Party Efficiency Providers

Several states have implemented third-party energy efficiency utilities, such as Efficiency Vermont and the Energy Trust of Oregon. Some advocates believe that by moving efficiency outside the utility, there is no longer a need for revenue decoupling, because the utility is no longer in a position to resist or obstruct energy efficiency investment. It is instructive that both Vermont and Oregon have found that revenue decoupling is a useful addition to a framework that includes a third-party provider, because utilities affect energy efficiency in many more ways than simply making grants and loans to consumers for energy efficiency measures.

11.6 Real-Time Pricing

Some academics have taken the position that dynamic utility pricing will result in efficient deployment of energy-efficiency measures, without any need for government or utility intervention. While advanced pricing has many advantages, it does not in any way overcome the multiple barriers to energy efficiency — such as access to capital, perfect information, or short time horizons of consumers, particularly renters. These barriers have been well-documented, and no form of energy pricing has been demonstrated to overcome them.

34 See Moskovitz, David, *Profits and Progress Through Least Cost Planning* for a detailed discussion of the problems with FACs and PGAs at: http://www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf

12 Decoupling Is Not Perfect: Some Concerns Are Valid

There are many critics of decoupling, and many different issues that they criticize. Decoupling is not a perfect form of regulation — but neither is conventional regulation. Both seek to set prices for utility service that approximate the cost of providing that service. Both seek to provide incentives for management to take actions to reduce costs and to maximize profits.

In this section, we discuss some of the common critiques of decoupling mechanisms, recognizing that all forms of regulation involve compromise.

12.1 "It's an annual rate increase."

Some rate case participants view decoupling as an annual rate increase without a rate case. This may be the case if the use per customer is declining over time, but it does not provide any indication of whether customer energy bills are rising or falling. That may be due to utility programs and policies, or it may be due to other factors that can be taken into account in the design of the decoupling mechanism.

If the decline in usage per customer is due to utility programs and policies, an annual upward rate adjustment (which produces annual decreases in annual bills due to declining usage) may be exactly why the decoupling mechanism was created. If energy efficiency is less expensive than energy production, then customer energy bills are declining. Absent decoupling, the utility would likely be filing annual rate cases, creating a significant workload on the Commission and leading to similar rate increases, since the underlying causes are the same.

To the extent that less frequent rate cases produce fewer opportunities for consumers to present policy issues to the Commission, it is probably appropriate for the regulator to create an alternative forum for such policy review. One approach, for example, might be for the regulator to initiate a general rate case at least once every three to five years, to ensure that the allowed revenues under decoupling do not deviate too far from the utility's underlying costs.

12.2 "Decoupling adds cost."

This reflects a misunderstanding of decoupling. Decoupling increases the likelihood that the revenue requirement found appropriate in a rate case will be the amount actually collected from customers. Certain decoupling elements (e.g., adjustments for inflation, productivity, and numbers of customers) project how those approved costs might change, and allow these changes to be reflected in future collections; but these changes represent costs that are likely to be approved in a rate case, because they are essential to providing service. Decoupling itself adds no significant new costs; to the extent that decoupling reduces the frequency of general rate cases, it can significantly reduce regulatory costs.

12.3 "Decoupling shifts risks to consumers."

Full decoupling means that utility profits are no longer adversely affected by weather conditions that reduce sales volumes, and some critics consider this a shift of weather risk to consumers. This is a fundamentally flawed argument. First, decoupling also removes the profit enhancement that occurs under traditional regulation when weather conditions cause sales increases. Second, with current decoupling, although prices go up when sales go down, they do so simultaneously, so that customer bill volatility is reduced, a benefit to consumers attempting to live within a budget. In addition, when sales go up, prices come down, thereby mitigating the bill's impacts. In this sense, decoupling mitigates earnings risk for utilities and expense risk for consumers, making both better off — and in the process, it creates the earnings stability to justify a lower overall cost of capital, which reduces absolute costs to consumers.

12.4 "Decoupling diminishes the utility's incentive to control costs."

In fact, precisely the opposite is true. Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of *revenue*. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the *only* means by which it can boost profits.

Because decoupling provides recovery of lost margin due to customer conservation efforts, however, it may extend the period between general rate cases. This is particularly true if aggressive utility conservation efforts are producing significant declines in customer usage; absent decoupling, this sales decline will trigger rate cases. This longer time period provides a stronger incentive for the utility to achieve operational efficiencies and reduce costs, because the utility will be allowed to retain the cost savings for a longer time, until the next general rate case. If costs and revenues become unbalanced for any reason, the utility or the regulator can initiate a general rate case at any time.

12.5 "What utilities really want sales for is to have an excuse to add to rate base —that is, the Averch Johnson Effect."

In a rate case, the net-income line item in the cost of service is a function of the size of the rate base and the return allowed>>. The greater the rate base, the greater the net income that is included in the cost of service (for a given allowed return). Utilities may be motivated to increase sales in order to add to rate base capital assets needed to serve additional load, despite countervailing risks associated with permitting and construction, for instance. This is not a concern decoupling can address, nor is it intended to address. Rather, sound integrated resource planning that identifies the least-cost long-term resource acquisition strategy is the best way to manage incentives associated with the capital program.

12.6 "Decoupling violates the 'matching principle.'"

The matching principle in ratemaking is an implicit assumption that revenues, sales, and costs will move in synchronization: as sales change (go either up or down), revenues and costs will change at the same rate. Absent changes in customers, programs, or policies, this has been generally effective in allowing traditional regulation to function effectively. Implied in the matching principle is that inflation is offset by productivity, and that new customers are about the same in terms of usage, revenue, and cost of service as existing customers. However, as discussed in the sections *How Traditional Regulation Works and How Decoupling Works,* it is the very fact that the matching principle does not hold true (that is, that marginal revenue almost always exceeds marginal cost in providing distribution service) that drives the need for decoupling.

Correspondingly, a change to a more comprehensive approach to energy efficiency means that deliberate programs and policies are implemented to achieve sales reductions for which there are no corresponding cost reductions, at least (for the most part) in distribution services. The very circumstances that counsel most regulators to consider decoupling — a desire to step up the rate of achievement of customer energy efficiency — directly undermine the foundation of the matching principle.

12.7 "Decoupling is not needed because energy efficiency is already encouraged, since it liberates power that can be sold to other utilities."

This condition does exist in some low-cost utilities that have excess capacity available for sale and that do not have FACs. Any utility with a traditional FAC does not benefit from off-system sales, because those revenues are credited to their retail consumers through the adjustment clause.

This concern, however, overlooks the temporary nature of excess capacity, especially if some of it is the result of an aging generation approaching retirement, and the changing nature of power markets. Decoupling encourages utilities to take actions that may increase off-system sales revenues, but only if power costs are covered by a decoupling mechanism will those sales result in increased profits for the companies.

Lastly, off-system sales have less certainty and are subject to the vagaries of market prices, whereas sales to native loads are more certain and subject to less price volatility. Conservative utility managers are likely to prefer the "bird in hand" in such cases.

12.8 "Decoupling has been tried and abandoned in Maine and Washington."

Maine and Washington initiated decoupling mechanisms in the late 1980s and early 1990s, and both terminated the programs after a few years. The reasons for termination were different.

In Maine, the decoupling mechanism was instituted for Central Maine Power shortly before a serious recession hit the country. Sales declined and the decoupling mechanism generated significant rate increases, because of the large annual adjustment resulting from the use of an accrual methodology. The Commission elected to discontinue the mechanism. Of course, for the most part, decoupling only implemented what a new rate case would have yielded in any event, the root cause of the problem not being the mode of regulation, but the recession. The lesson learned is that a cap on annual rate increases may be appropriate, and a complete review of costs, sales, and revenues (i.e., a general rate case or equivalent) should be required every few years under a decoupling mechanism.

In Washington, a decoupling mechanism applied to "base costs" was introduced at the same time that a separate mechanism was introduced to recover "power costs." The utility (Puget Sound Power and Light Company) was acquiring significant new resources to replace expiring power supply contracts. Rates went up sharply due to the operation of the power cost mechanism, not the decoupling mechanism. The increases raised public concerns, and the public utility commission (PUC) opened an inquiry into the Puget's resource decisions. The Commission found that, with respect to certain power supply contracts, the utility had acted imprudently. The combined mechanism was terminated. The rate adjustments due to the decoupling portion had been minor, and were not the primary focus of the Commission's inquiry. Shortly thereafter, Puget applied for a merger with Washington Natural Gas Company. A multi-year rate plan was approved as part of the merger, displacing both the power-cost and base-cost decoupling mechanisms.

12.9 "Classes that are not decoupled should not share the cost of capital benefits of decoupling."

Many commissions have excluded large-volume electricity and natural gas consumers from decoupling mechanisms. The reason for this is that classes of customers with few members may really require customer-specific attention in ratemaking, and a decoupling mechanism could result in significant rate increases to remaining customers if another customer or customers in the class discontinued or reduced operations.

Because decoupling results in a lower risk profile for the utility, particularly with respect to weather and economic cycles, it is expected (either immediately or over time) that a reduction in the cost of capital will result. A class that is not exposed to decoupling rate adjustments due to sales variations is not a part of the cause of the lower risk profile. However, because Commissions normally apply the same rate of return to all classes, it may not be pragmatic to calculate a different rate of return for each class.

As a practical matter, large-use customer classes often have other revenue stabilization elements in their rates, such as contract demand levels, demand ratchets, and straight fixed/variable rate designs that have a stabilizing effect on revenues similar to that of decoupling. Consequently, one might argue that, under traditional regulation, the classes with more variable loads were benefiting from the risk-reducing nature of larger-volume customers, and that decoupling merely balances the scales.[35]

35 But it is fairer to say that all loads impose both risks and benefits on the utility. A large-volume user may have a higher-than-average load factor and provide stable revenues to the utility, but the adverse impacts of its leaving the system are significantly greater than those of individual lower-volume customers. Many factors affect the market's valuation of the risks that a utility faces; load diversity is only one of them.

12.10 "The use of frequent rates cases using a future test year eliminates the need for decoupling."

A future test year may have the effect of causing a utility's "revenue requirement" to more closely track a utility's revenue requirement over time. A future test year does not, however, have the effect of constraining *allowed revenues* to a utility's revenue requirement. In addition, a future test year does not address the throughput issue, which is one of the primary reasons for using decoupling. The term "decoupling" itself is rooted in the notion of separating the utility's incentive to increase profits through increased sales, and to avoid decreased profits through decreased sales by breaking the link between — that is, by decoupling revenues from sales.

12.11 "Decoupling diminishes the utility's incentive to restore service after a storm."

This can be a problem if not addressed in the design of the decoupling mechanism. After a storm, utilities normally bring in extra crews, pay overtime, airlift in supplies, and otherwise do everything reasonably possible to restore service. The primary reasons for this are the deeply-held sense of obligation that drives utilities and their employees to provide reliable service and their appreciation of the far-reaching and deleterious impacts of an outage.

But there is also a more prosaic motive: the need to "get the cash register running" again, so revenue flows to the utility. If a decoupling mechanism allows the utility to receive the revenues that it would have collected if the power were on, consumers both suffer an outage and pay for service they did not receive. The utility is made whole, and really does not suffer any penalty from slow service restoration.

This is easily addressed in the design of an RPC decoupling mechanism. One approach would be to adjust the number of customers for whom the allowed revenue is computed to reflect only those who were receiving service during a particular time period, deducting days when power was unavailable. (This same concern applies equally to straight fixed/variable pricing: the charges to consumers must be halted during an outage, or the incentive to restore service is diminished.) Another approach would be to address service quality issues such as outages separately, in a comprehensive Service Quality Index, with penalties tied to outage frequency and duration.

12.12 "The problem is that utility profits don't reward utility performance."

At least two states have tried to overcome utility resistance to energy efficiency investment by allowing a higher rate of return for investment in energy efficiency than utilities receive on supply-side investments. While this can work in theory, it is difficult to make it work in practice, because the incentive return must be quite high to overcome the lost margin effect that decoupling addresses. In addition, a premium return may tend to reinforce the Averch-Johnson effect, giving utilities an incentive to spend as much as possible (to attract the incentive return) on measures that save little or no energy (to avoid creating lost margins). An incentive return mechanism can be a very important part of regulation, for example, by tying the utility's return (or the utility's recovery of deferral margins under decoupling) to the utility's achievement of energy efficiency achievement and cost control targets approved by the commission. But, as a general matter, incentive return mechanisms have not been effective alternatives to decoupling; in combination *with* decoupling, however, they can be.

13 Communicating with Customers about Decoupling

Preparing a utility's customers for the effects of decoupling on their bills can be a challenge, both because the components of a utility's bill are not always straightforward, indeed are often confusing, and because variable prices are a new phenomenon to most. Regulators, utilities, and consumer advocates should all want to make the transition to decoupling as smooth as possible for customers. This requires some thought about bill design and consumer education. The guiding principle here should be simplicity. In fact, the implementation of decoupling offers an opportunity to overhaul the utility's bill with an eye toward simplification.

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices. Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 13a shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 13b shows what the customer actually pays if they use more electricity, or saves if they use less electricity. Utilities should be encouraged to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Tables 13a and 13b show a conversion of a rate with multiple surcharges into an effective rate.

Table 13a

Example of an electric bill that lists all adjustments to a customer's bill			
Your Usage: 1,266 kWh			
Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:			$139.74
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

Table 13b

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design			
Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

A secondary issue is whether the changes in price occasioned by decoupling should, themselves, be detailed in a line item on the bill or subsumed in a total price. We are all familiar with changing prices at the gas pump, but do not expect a "line item" description of the latest adjustment up or down in that price. We expect to pay the price on the sign, and expect it to include all taxes, fees, profit, transportation charges, and other elements of cost. In fact, if gas stations were required to track price changes in such a way, consumers would see a confusing array of information that is largely unrelated to changes in the total price being paid. Again, simplicity argues for rolling the decoupling adjustments directly into the total price, rather than having a separate decoupling adjustment line item. The full detailed tariff must be available for the customer to review, generally on the utility website, but it may not need to be on the bill; only the effective prices – what a customer pays if he or she uses more or less service – is relevant to the consumption decision.

When decoupling is implemented, a communication strategy should be in place to help consumers understand why prices are being allowed to vary from bill to bill. They may see decoupling as a "profit guarantee" rather than a "revenue assurance." Information making clear the ultimate impacts of decoupling will likely be more understandable than a brochure that attempts to, say, summarize the contents of this guide.

Aside from the total size of their bills, customers tend to be most concerned about whether they are being fairly charged by their utility. Decoupling strikes to the heart of this issue because, unlike traditional regulation, it has a high probability, if not certainty, that consumers will actually pay the revenue requirement determined by the Commission. In addition, where weather risk is eliminated, decoupling has the effect of countering the impacts of high bills during extreme weather (with the symmetric effect of slightly increasing bills during mild weather).

Most consumers would likely welcome a little "help" when the bills are higher than usual, at the "cost" of a slightly higher bill when bills are lower. This is merely the softening of the peaks and valleys. It is these aggregate effects that consumers should understand, and which a communication strategy should address.

14 Conclusion

Revenue regulation and decoupling provide simple and effective means to eliminate the utility throughput incentive, remove a critical barrier to investment in effective energy efficiency programs, stabilize consumer energy bills, and reduce the overall level of business and financial risk that utilities and their customers face.

This guide has identified and explained key issues in decoupling for the benefit of regulators and participants in the regulatory process alike. Each utility and each state will be a little bit different, so there may not be a cookie-cutter approach that is right for all. However, the principles remain fairly constant: minor periodic adjustments in rates stabilize revenues, so that the utility is indifferent to sales volumes. This eliminates a variety of revenue and earnings risks, in particular those associated with effective investment in end-use energy efficiency, and can bring provision of least-cost energy service closer to reality for the benefit of utilities and consumers alike.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

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List of Acronyms

BGE	Baltimore Gas and Electric
CPUC	California Public Utilities Commission
C&I	Commercial and Industrial
DG	Distributed Generation
DPU	Department of Public Utilities
DSM	Demand-Side Management
FCA	Fixed Cost Adjustment
GAAP	Generally Accepted Accounting Practices
GRC	General Rate Case
HECO	Hawaiian Electric Company
IPC	Idaho Power Company
kWh	Kilowatt-Hour
MECO	Maui Electric Company
O&M	Operation and Maintenance
PCA	Power Cost Adjustment
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PSC	Public Service Commission
PSCW	Public Service Commission of Wisconsin
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account
ROE	Return on Equity
RPC	Revenue Per Customer
RSM	Revenue Stabilization Mechanism
TOU	Time-Of-Use
WPS	Wisconsin Public Service Corporation

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Introduction:
Policy Overview for Decoupling

Over the last several decades there have been major shifts away from the traditional utility service paradigm in which the local utility supplied customers with all their resource needs, and those resource needs were met through the construction and operation of power plants. Some states have restructured their electric utilities so that the resource supply is a competitive service. Others have maintained the traditional vertically integrated model, while other states have developed hybrids combining features of each. Also different today is the expectation that the customer demand for electricity will be provided exclusively from power plants. Energy efficiency as a substitute for new power plants to meet customer needs has been gaining acceptance in the regulatory world, significantly during the last decade. Moreover, as the price of renewable resources used for distributed generation (DG) continues to decline, there has been a growth in the adoption of on-site generation by customers as they demand a more diverse set of services. The potential for deployment of customer-side resources of all types is large.

Traditional regulatory practice creates an environment in which the utility is able to earn more profit by selling more electricity. Because of this dynamic, the utility is essentially in competition with the customer, as well as with private sector companies that provide services, to supply the energy needs of that customer. This can greatly impede the ability of the marketplace to achieve the optimal least-cost solution for energy services. A regulatory scheme that depends on increasing throughput as a means for achieving earnings is likely to be increasingly out of step with customer needs and desires—and with public policy objectives—in the coming years. As the utility service environment changes, so too must regulation as customers demand more and different services and as regulators increasingly encourage clean energy outcomes. The growth in customer-sided resource options compounds the challenge of net lost distribution revenues for utilities, especially as it affects their ability to maintain and upgrade their grid infrastructure. Thus, as nontraditional resources (that are neither supply options nor provided by the utility) are proliferating, revenue regulation, while not a silver bullet, becomes even more important as a means of managing revenues and removing utility barriers to adoption of these alternatives.[1]

Although the concept of increasing energy efficiency and DG may be fairly straightforward, the impact and reaction of electric utilities to engage in comprehensive energy efficiency and encourage DG is not. Ask any business how it makes money and it will invariably respond that it does so through increasing the number of units of the products it is selling, through growth. Energy efficiency requires utilities to do the exact opposite of the traditional model, and instead requires the utility to market and promote buying less of its product. The net lost revenues that the utility will encounter as a result of these activities is no trivial matter, especially as energy efficiency programs ramp up. Many states have Energy Efficiency Resource Standards requiring cumulative reductions in consumption by 20 to 25 percent in the 2020 decade. Others have commission-ordered energy efficiency portfolio requirements, requiring similar reductions in consumption. A new study cosponsored by The Edison Foundation Institute for Electric Innovation found that electric utility efficiency programs saved 126 terawatt-hours of electricity in 2012. If utilities were unable to collect two cents per kilowatt-hour (kWh) contribution to fixed costs as a result of these efficiency program savings, they would experience a significant reduction in returns.

The growth in DG will also impact utility sales, and have a similar impact on revenue as energy efficiency. According to a Bloomberg report, financial investments in DG have grown from $19 billion in 2004 to $143 billion in 2010.[2] The onsite energy production from these investments will decrease utility sales from what they otherwise would have been, and could result in absolute decreases in sales in states that have strong energy efficiency programs and low baseline growth. As states pursue a more aggressive efficiency agenda, there might come a point where the current rate-setting model is no longer sustainable. Utilities have embedded investment-related and labor costs (not sensitive to volume)[3] included in their rates to support investments already made and necessary for good service, reliability, safety, and other utility services, which are adjusted during periodic rate cases.

1 For an in-depth discussion of revenue regulation, see: Shirley, W., Lazar, J. & Weston, F. *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

2 Bloomberg New Energy Finance. (2011). *Global Trends in Renewable Energy Investment 2011,* UNEP SEFI Frankfurt School, Global Trends in Renewable Energy Investment.

3 Technically, the only truly "fixed" costs for a utility are interest and depreciation. Labor costs are technically variable costs, but they vary little in the short-run in response to sales volumes. Over a long time, one or more decades, some costs that are fixed in the short-term, such as transformers and conductors, are revealed to be volume- and usage-sensitive, especially when assets and systems are replaced.

Without a mechanism in place to address the utility impact of reduced sales, the lost revenues from energy efficiency programs and DG will make it more difficult for utilities to cover their fixed cost obligations and to reach their earnings targets for shareholders. As a result, various strategies to allow utilities to recapture these lost revenues have been developed. Environmental imperatives, including promotion of customer-side alternatives to utility supply, motivate regulators to consider forms of regulation in which sales do not matter and utilities are motivated to find the best investments to meet public policy objectives irrespective of which side of the meter it resides or what degree of utility control is maintained.

Lost revenue recovery allows utilities to recover the deficit in revenue resulting from reduced sales.[4] There are several mechanisms that accomplish this: lost revenue adjustment mechanisms, straight-fixed variable rates, and revenue regulation. Only one of these mechanisms, decoupling - revenue regulation, however, accomplishes the dual goals of both removing the throughput incentive and continuing to send more economically appropriate price signals to customers. Both of these principles are key to successful energy efficiency programs.[5]

Revenue regulation, however, is a not a single distinct mechanism. Rather, there are various elements that can be assembled in numerous ways based on state priorities and preferences that serve to eliminate the throughput incentive. This publication will focus on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples provide a range of options on how to implement revenue regulation. After considering the decoupling mechanisms of numerous utilities across the nation, these specific utilities were chosen in order to provide examples across many regions, and also to contrast the different approaches taken by each utility to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked.

4 Strictly speaking, it is *net* lost revenue that is at issue. To the extent that avoided sales avoid some amount of variable cost (low in the case of delivery services only), that avoided cost should be netted from the foregone gross revenue, in order to calculate the correct amount of revenue that would have otherwise gone to cover the company's return of and return on investment. Revenue regulation solves this problem automatically. In contrast, lost revenue adjustments require these calculations, which predictably become quite contentious in the rate-making process.

5 Although this paper does not focus on the rationale for sending appropriate price signals, references on this issue can be found at: Lazar, J., Schwartz, L., and Allen, R. (2011) *Pricing Do's and Don'ts.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Lazar_PricingDosandDonts_2011_04.pdf, and Lazar et al. (2011).

Rate adjustments under a revenue regulation scheme do not represent additional costs to ratepayers, but are a reallocation of approved, recoverable costs to a changing base of retail sales. Rates are set assuming a certain sales volume, and many costs that do not vary with usage in the short run are collected through a volumetric sales rate. When a utility engages in programs or policies that result in lower customer usage, some revenues that should have offset some of these costs are not billed to customers as a result (and vice versa where usage increases). The revenue regulation adjustment tracks those lost revenues and allows recovery in a subsequent period. In all cases, the revenue regulation adjustment represents a reconciliation of revenues that were approved for collection from customers that were not collected as a result of changed sales volumes. Revenue regulation adjustments can also result in reduced rates when excessive revenues are collected due to weather or other variations in sales amounts.[6]

Background: Measuring the Success of Decoupling/ Revenue Regulation Mechanisms

A revenue regulation mechanism designed to promote energy efficiency may be viewed as successful if the utility is no longer concerned about increases and decreases in sales, is no longer taking actions to increase sales or reduce decreases in sales, and is improving the overall efficiency of its operations and management. Although a particular mechanism can be designed to meet other goals (other performance goals, with dedicated metrics and specific rewards and penalties attached), this paper is primarily concerned with mechanisms designed to mitigate revenue losses that can impede the desire of a utility to aggressively pursue programmatic energy efficiency. By taking an in-depth look at six diverse utilities that have implemented revenue regulation, this study describes the similarities and differences among the adopted mechanisms and attempts to answer the question of how each is working to achieve its goals.

A second significant determinant of the success of a revenue regulation mechanism is its acceptance by the stakeholders. This can be manifested by a lack of objection or support of revenue regulation by consumers and

6 For a detailed analysis of the economic and public policy rationales for revenue regulation, see: Lazar et al., 2011. See also: Shirley, W., Lazar, J., & Weston, F. (2008). Revenue decoupling: standards and criteria: A report to the Minnesota Public Utilities Commission. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Shirley_DecouplingRevenueRpt_2008_06_30.pdf

it can be manifested through changes in utility behavior that customers respond to. Revenue regulation provides utilities who act prudently and in accordance with the mechanism assurance that they will collect their allowed revenues. As a result, they are better able to focus on other activities, such as programmatic energy efficiency, that reduces costs in the long run. The utilities studied also found benefits to include providing customers with a lower-cost product, improved customer interaction, and other efforts as sanctioned by the regulator that will produce additional revenue streams. Indeed, the Oregon Commission recognized as much when it commented on Portland General Electric's (PGE) ability to influence individual customers through direct contacts and referrals. The Commission also noted that PGE can influence usage depending on how aggressively it pursues DG; whether it supports improvements to building codes; and whether it provides timely, useful information on energy efficiency programs.[7] Engaging actively in these programs can also help develop better customer relationships as the utility industry evolves to a more service-oriented business. Instead of just handing customers a bill, the utility can be providing them efficiency-based solutions that serve cumulatively to avoid more expensive ways to meet customer demand.

Financial incentives for specified performance—relating to energy efficiency achievements or improvements in customer service, to name only two—are examples of ways to influence utility behavior in furtherance of public policy objectives. If awarded, such incentives are included in periodic adjustments to the allowed revenue. One goal is to turn the utility from being a reluctant participant to being an enthusiastic advocate for (or at least not an active inhibitor of) energy efficiency while creating a stable regulatory environment to accomplish other complementary policies. Moreover, combining revenue regulation with performance incentives creates a stronger inducement for utilities to engage in least-cost planning, which benefits its customers.

Environmental groups will want to ensure that there are robust programs and policies in place that advance clean energy solutions. Consumers will be cautious about rate impacts that will need to be addressed in the design of a decoupling mechanism (see text box on next page).

Striking a balance among competing stakeholder concerns while creating effective mechanisms to advance good public policy falls to the regulators and, as will be seen in the six case studies, there seems to be no generally accepted approach. This demonstrates that revenue regulation is not a static, one-size-fits-all policy, but rather it can be fashioned in a number of ways to

7 Oregon Public Utility Commission. Order No. 09-020, p 27.

meet the needs of any given community.

An additional way to evaluate the success of a revenue regulation mechanism is to look at the rate impacts and how manageable they are. Most annual rate impacts from revenue regulation fall between plus or minus one to three percent. These impacts are generally manageable and may in fact be less than the fluctuations customers might otherwise experience with fuel adjustment clauses or under a variable generation rate. Over the long term, observers might expect to note avoided load-driven capital costs and other long-lived commitments.

Another measurement of the success of decoupling is how the results of its implementation are viewed by financial institutions. Revenue regulation can be a factor considered by the rating agencies in determining a bond rating for a utility. With multiple mergers and the creation of holding companies with subsidiaries, it becomes more difficult to measure this because there are multiple utility companies and affiliates in multiple states that are being evaluated. Nevertheless, Standard and Poors noted that revenue regulation mechanisms were a positive factor and that they would better align the interests of consumers with utility shareholders by implementing rate designs that encourage energy efficiency.[8]

Some consumer groups have expressed concerns with decoupling, because, depending on how it is designed, there could be future rate adjustments that are not subject to the same rigorous review as would occur in a rate case. Below is a list of considerations in designing revenue regulation mechanism that attempts to address those concerns:

- Making revenue regulation contingent on a robust energy efficiency commitment and portfolio;
- Requiring structural symmetry in the mechanism, such that credits as well as surcharges flowing from a reconciliation be accounted for and refunded to customers;
- Creating a bandwidth around the amount of adjustment permitted in any given year;
- Adjusting the cost of capital or, more appropriately, the imputed capital structure, to reflect lower risk; and,
- Requiring periodic rate cases to assess the appropriate level of revenues for the utility—which is helpful only if the utility's revenue requirement is set too high and does not account for downward adjustments in costs such as reduced labor expense.

8 Standard and Poor's. (2012, May 15). Poors. Credit Matters Report.

Because revenue regulation reduces the utility's risk profile by providing revenue and earnings stability, the upside can be a better credit rating from the major rating agencies. Alternatively, the utility may be able to retain the existing credit rating with a lower common equity ratio in its capital structure. A better credit rating or lower equity ratio can translate into a lower financing rate, which benefits the utility and ultimately the customers who pay for utility-financed construction projects. These construction projects can include distribution and transmission upgrades or expansion as well as pollution control investments on existing generating units or, if necessary, new plant construction.

Finally, a more tangible means of ascertaining the success of a revenue regulation mechanism is whether there is an increase in energy efficiency and DG. Although some of the incremental increases may be motivated by statutory or regulatory requirements, a utility decision to increase or voluntarily go beyond the requirements through its own efforts or by assisting others, especially if innovative means are used to achieve these results, can be viewed as a demonstration that revenue regulation is working.

This publication contains an in-depth look at six instances of revenue regulation, representing a wide cross-section of such regimes in the United States. We look first at each utility and provide a summary of its revenue regulation mechanism. Next we discuss various components or decision points in designing a revenue regulation mechanism and look at how each state addressed that mechanism. What emerges is that despite the differences in designing revenue regulation, each mechanism is customized so that the pieces and parts fit together into a complete tableau. This is perhaps one of the most critical lessons to be drawn from these analyses, that is, that there is no one right way to do revenue regulation. What counts most is making sure that all the parts of a revenue regulation mechanism work together.

California:
Pacific Gas and Electric Company

Pacific Gas and Electric Company's (PG&E) revenue regulation mechanism compares authorized revenues plus annual attrition adjustments with non–weather-adjusted actual revenues and reconciles any over- or under-collection annually. The authorized revenues are established through a general rate case every three years based on a future test year. Each of PG&E's functional operating areas is decoupled and the authorized revenue requirement is determined separately for each unit: electric distribution, gas distribution, public purpose programs, and the like. During the general rate case, authorized revenues are also established for the two years following the future test year. Each year, an "attrition case" measures changes in the approved costs that have been experienced, and adjusts the test-year revenue requirement. Collected revenue is tracked through balancing accounts, and surpluses/deficits in these accounts are amortized and refunded/collected to or from ratepayers through rate adjustments in the following year. Revenue regulation applies collectively to all of PG&E's customer classes (i.e., deviations in sales revenues relative to forecasted levels are tracked and reconciled at the system level). The revenue regulation mechanism is in addition to adjustments for PG&E's electric and gas energy procurement costs.

Authority

California first adopted revenue regulation for gas utilities in 1978. By 1982, the California Public Utilities Commission (CPUC) put revenue regulation in place for its three major electric investor-owned utilities, PG&E, Southern California Edison, and San Diego Gas & Electric. The original construct, called the Electric Revenue Adjustment Mechanism, established a revenue requirement for each utility annually and then reconciled billed revenues to authorized revenues. The Commission determined that the mechanism would "eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned."[9] However, the CPUC largely

9 CPUC Decision 93887 12/30/1981.

suspended the electric revenue regulation mechanisms in 1996 owing to the implementation of electric restructuring.

In 2001, the California Assembly passed Assembly Bill 29, which established programs to reduce energy usage in the wake of the Western Energy Crisis and required that "[t]he commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collection of the electrical corporations."[10] Now incorporated into the Public Utilities Code, section 739.10, this required the CPUC to re-implement revenue regulation. The CPUC first re-implemented revenue regulation for PG&E in 2004, when the company came out of Chapter 11 bankruptcy following the Western Energy Crisis.

Authorized Revenue Requirement

The CPUC determines PG&E's authorized revenue requirement through a General Rate Case (GRC) every three years. Each of PG&E's functional operating areas is decoupled and the Commission determines a separate authorized revenue requirement for each area.

In order to determine the appropriate revenue requirement and rates, a future test year is used, meaning that the costs included in the revenue requirement and sales levels used to determine rates are forecasted. For example, on December 21, 2009, PG&E filed its application for the 2011 GRC. This GRC used the future test year 2011 to determine PG&E's authorized revenue requirements in 2011. The test year revenue requirement includes both projected expenses and capital expenditures.

The electric distribution revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain:
  - Its distribution plant;
  - A portion of its transmission plant providing service directly to specific customers and connecting to specific generation resources; and
  - A portion of its common and general plant; as well as
- Provide services to its electric customers.

The generation revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain its electric generating plant; and
- Perform the transactions necessary to procure electricity for its bundled-service electric customers.

10 Assem. Bill 29, ch 8, 2001 Cal. Stat. http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_29_bill_20010412_chaptered.pdf

Because all customer classes are decoupled, the revenue requirement also includes costs related to serving all customers.

In the 2011 GRC, PG&E received a total revenue requirement of $5977 million. The retail revenue requirement for electric distribution was $3190 million, for gas distribution $1131 million, and for electric generation $1656 million.

Rate of Return

CPUC calculates the authorized revenue requirements for PG&E based on a rate of return on its rate base of 8.79 percent, which is projected to provide an 11.35-percent return on equity. Although intervening parties in the state's consolidated cost of capital proceedings have alleged that revenue regulation reduces financial risk, there has been no explicit reduction of the return on equity or debt-equity ratio attributable to the implementation of revenue regulation.

Costs Not Included in Revenue Regulation

According to PG&E, only approximately six percent of its electric revenues are "at risk," meaning not decoupled or tracked through another mechanism; only 4.2 percent of natural gas revenues are not decoupled.[11] In addition to energy procurement costs, revenue regulation does not apply to PG&E's FERC-regulated electric transmission revenue requirement or to a portion of PG&E's gas transmission and storage revenue requirement. Costs not included in PG&E's revenue requirement include energy procurement costs.

Revenue Adjustment Mechanism

PG&E's revenue adjustment mechanism allows for two methods for changing the authorized revenue requirement between rate cases. The first mechanism is the stair-step method, through which adjustments to the revenue requirement are predetermined during the GRC. Second, PG&E's revenue adjustment mechanism allows for changes in the post–test-year revenue requirements, in addition to the predetermined adjustments, for "exogenous changes."

During the GRC, the CPUC also determines the authorized revenue requirements, called post–test-year attrition increases, for the two years following the test year. In the 2011 GRC, the Commission determined the authorized revenue requirement for the future test year 2011 in addition to the post–test-year attrition increases for 2012 and 2013.

11 Risser, R. (2006, August 2). *Decoupling in California: more than two decades of broad support and success.* Presentation to the NARUC Workshop on Aligning Regulatory Incentives with Demand-Side Resources.

The annual attrition adjustments were fixed dollar amounts of $180 million in 2012, and $185 million in 2013, except for allowed exogenous changes. In this context, attrition refers to the decrease in utility revenues compared with costs between rate cases; attrition adjustments refer to adjustments to the authorized revenue designed to allow the utility to recover the increased costs. The 2012 increase includes $123 million for electric distribution, $35 million for gas distribution, and $22 million for electric generation. The 2013 increase includes $123 million for electric distribution, $35 million for gas distribution, and $27 million for electric generation.

Next, PG&E's attrition mechanism allows adjustments to the post–test-year revenue requirements for exogenous factors, limited to five factors, which are determined during the GRC. The five factors determined through the 2011 GRC to be applied to the 2012 and 2013 attrition adjustments are: postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, and ad valorem tax changes. A $10 million threshold is applicable to each factor each year.

Reconciling Actual Revenue With Authorized Revenue

Since 2004, PG&E has utilized balancing accounts to implement revenue regulation. Balancing accounts track the difference between billed revenue and the authorized revenue requirement each month in order to determine the total annual under- or over-collection of revenue. The revenue balancing accounts (RBAs) are credited each month with billed retail revenue and debited each month with the total amount of authorized annual revenue divided by 12. Any surplus or deficit is tracked and all monthly surpluses and deficits are totaled at the end of the year. The total annual surplus or deficit, plus interest, is amortized and refunded to or collected from ratepayers in the following year through a rate adjustment. PG&E uses different balancing accounts to track specific revenue streams separately and recover or refund over or under-collections separately. For example, PG&E may over-collect distribution revenue, leading to a surplus in that account and requiring a refund to ratepayers. In the same period, the utility could under-collect public purpose revenue, leading to a deficit in that account, which would be recovered from ratepayers. It is possible that from a ratepayer perspective, refunds from surplus accounts and recovery from deficit accounts could cancel each other out. PG&E tracks numerous revenue streams through balancing accounts, including:[12]

- Distribution Revenue Adjustment Mechanism;

12 PG&E. *Tariff Book.* Available at: http://www.pge.com/tariffs/EPS.SHTML

- Public purpose program Revenue Adjustment;
- Nuclear decommissioning Adjustment Mechanism;
- Utility Generation Balancing Account; and
- Regulatory Asset Revenue Adjustment Mechanism

Generally, rate adjustments apply equally to all customers in all rate schedules, with some exceptions. For example, direct access customers are exempt from changes in generation costs. Revenue regulation rate adjustments occur annually, with rate adjustments attributable to over- or under-collection in a year being effective January 1 the following year. CPUC requires PG&E to file an Annual Electric True-Up advice letter by September 1 of each year with its preliminary forecast of electric rate changes expected, including revenue regulation and other adjustments. The account balances as of December 31 will determine the final changes to rates that become effective on January 1. In its 2012 Annual Electric True-Up advice letter, PG&E included 23 balancing accounts that were approved for that year.[13]

Complementary Policies

California has implemented energy savings goals for its investor-owned utilities, calling for approximately one-percent savings annually through 2020. The Risk/Reward Incentive Mechanism, implemented in 2007, provides an incentive if the utility meets at least 85 percent of its savings goals. Utilities can receive 9 percent of net benefits if they achieve between 85 and 99 percent of savings goals and 12 percent of net benefits[14] if they meet or exceed savings goals up to the earnings cap of $450 million. Penalties are triggered when actual energy efficiency savings are at or below 65 percent of the individual utility savings goal. First, utilities must reimburse ratepayers dollar-for-dollar for any negative net benefits; this is considered part of the penalty payment. Utilities must also pay a per-unit penalty rate of $0.05/kWh and $25/kW. The total penalty is also capped at $450 million.

PG&E currently offers residential customers service under a default inclining block rate structure. Residential customers may volunteer for time-of-use (TOU) rates, with peak, part-peak, and off-peak tiers for summer, and part-peak and off-peak tiers for winter. Discounted rates for low-income and medically fragile customers are available, but they too are inclining. Commercial customers take service on a Peak Day Pricing default rate but can opt out to take service under a TOU structure. Peak Day Pricing is TOU pricing with a surcharge added on top during 9 to 15 peak events called

13 PG&E. (2012, August 31). *Annual Electric True-up Filing*. Available at: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4096-E.pdf

14 ACEEE. *California*. Available at: http://database.aceee.org/state/california

during the year. Each of these rate structures signals customers that increased use of energy will be increasingly more expensive. These rate designs create a situation in which utility revenues are greatly affected by weather, whereas their investment and labor costs are not; the revenue regulation mechanism buffers utility revenues and earnings from these weather effects.

Some Commissions have implemented service quality programs to ensure that utilities don't engage in destructive cost cutting to improve margins under revenue regulation. PG&E files annual reliability reports, but there is no explicit penalty or reward associated with performance. However, a new initiative by the CPUC is exploring how to elevate the importance of safety in gas and electric utility rate cases, which would be supported through a performance-based ratemaking platform.

Energy Efficiency Outcomes

Because PG&E has been decoupled in one form or another since 1984, it is very difficult to determine the effect of revenue regulation on the implementation of energy efficiency programs. However, PG&E has reported that incremental energy efficiency savings have consistently exceeded one percent of retail sales over the last ten years.[15]

Resources

California Division of Ratepayer Advocates

Report on the Cost of Capital for Test Year 2013, Docket A. 12-04-015 (August 6, 2012)

California Public Utilities Commission

Docket 09-12-020
  Settlement Agreement (May 13, 2011)
Docket 10-07-027
  Decision 11-05-018 (May 5, 2011)
Resolution E-3862 (April 1, 2004)

Pacific Gas and Electric Company

Advice Letters 3896-E, 3896-E-A, 3896-E-B:
  Annual Electric True-Up and Supplemental Filings (January 23, 2012)
Advice 3727-E: Annual Electric True-Up Filing (September 1, 2010)
  General Rate Case Application of Pacific Gas and Electric Company (December 21, 2009)

15 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Idaho:
Idaho Power Company

Idaho Power Company's (IPC) Fixed Cost Adjustment (FCA) mechanism compares the authorized fixed-cost revenue requirement with weather-normalized sales and reconciles the difference annually for residential and small business customers. The allowed revenue is determined on a per-customer basis during the general rate case, and the total fixed-cost recovery amount is adjusted based on the number of customers.

Authority

In 2004, the Idaho Public Utilities Commission established a case to investigate financial disincentives to investment in energy efficiency by IPC. After a series of workshops, in 2007 the Commission approved a three-year pilot of IPC's proposed revenue regulation mechanism. In 2009, the Commission extended the pilot for an additional two years, starting January 1, 2010. On April 2, 2012, the Idaho Public Utilities Commission made the IPC pilot program permanent.

Authorized Revenue Requirement

During the general rate case, the Commission establishes the class-specific portion of IPC's revenue requirement. For purposes of the FCA, this includes the fixed costs collected through Residential Service and Small General Service customer rates. During the general rate case, the Commission also establishes a fixed-cost per-customer rate—the amount of fixed cost revenue the Company will recover from each customer. Finally, the Commission must also establish the fixed-cost per-kWh rate—the portion of retail rates that covers fixed costs. "Fixed costs" are defined much more broadly than accounting standards provide, including return, taxes, and labor expenses.

Rate of Return

IPC's most recent rate case resulted in an overall settlement. The Stipulation specified an overall rate of return of 7.86 percent, which combines return on equity (ROE), capital structure, and cost of debt. The Commission made no explicit adjustment to the Company's allowed rate of return based on the implementation of the FCA.

Revenue Adjustment Mechanism

The revenue adjustment mechanism was designed to be weather normalized. For each customer class included in the revenue regulation mechanism, the actual number of customers (CUST) is multiplied by the fixed-cost per-customer rate (FCC) to give the allowed fixed-cost recovery amount. This pro forma amount is then compared to the fixed costs recovered by the company. This actual fixed-cost recovery is determined by taking the weather-normalized sales for each class (NORM) and multiplying it by the cost-per-kWh rate (FCE) as determined in a general rate case. The difference (allowed fixed cost recovery minus actual fixed cost recovery) determines the FCA. In this way, the revenue requirement is adjusted between rate cases based on the number of customers, and is weather normalized, leaving the weather risk with the company. This difference is the FCA and is applied to each decoupled customer class.

The mathematical formula is $FCA = (CUST \times FCC) - (NORM \times FCE)$. The number of customers is determined by class on the same basis as the methodology used in the general rate case.

Reconciling Actual Revenue With Authorized Revenue

Each month, the actual fixed-cost recovered amount is determined based on the weather-normalized sales for each customer class multiplied by the fixed-cost per-kWh rate. For reporting, a monthly "shaped" fixed cost per kWh is used for calculating actual fixed-cost revenue. This adheres to Generally Accepted Accounting Practices (GAAP) and better reflects end-of-year impacts within the year. The methodology used to weather-normalize actual monthly energy used in the FCA is the same as used in the general rate case. Finally, the actual fixed-cost recovered amount is subtracted from the allowed fixed-cost recovery amount and the difference is recorded as a line item in the monthly Power Cost Adjustment (PCA) report provided to the Commission. Differences are deferred with interest until the end of the year. The actual FCA balance will differ from that recorded in the monthly reports to reflect the fact that the deferral balance is calculated on an annual, not monthly basis. FCA balance is based on annual average prorated customer count, annual weather normalized sales, and non-shaped FCE rates, which would affect both the balance accrual and the associated interest.

Each year, the Company totals the FCA results, including interest, for the period from January 1 to December 31. If the total is negative, it represents an under-collection of revenue from customers and the amount will be recovered from ratepayers in the following year through an adder to rates (Schedule 54.) Likewise, if the total is positive, the Company has over-collected its fixed-cost revenue, and will return the excess amount to customers through an adder in rates using a credit or surcharge mechanism. These adjustments are currently included in the Annual Adjustment Mechanism line item on customer bills. Since July 2012, the Annual Adjustment Mechanism includes PCA and FCA to avoid customer confusion.

Originally, FCAs were calculated for each decoupled customer class; however, the FCA is now recovered proportionally between the residential and small general service customers for such reason as a lack of cost of service studies to support the underlying cost allocations and acknowledgment of the "portfolio" approach toward energy efficiency. Annual adjustments are capped at three percent and differences beyond that are rolled over until the next period. Adjustments to the rate occur June 1 of the year following the previous one-year period from January 1 to December 31.

IPC was initially obligated to submit its adjustment request, subject to Staff audit, on March 15 of each year. Under the pilot program, this included a detailed summary of demand-side management (DSM) activities that demonstrate an enhanced commitment to DSM resulting from implementation of the FCA. "Evidence of enhanced commitment will include, but not be limited to broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs, pursuit of energy savings programs beyond peak shaving/load shifting programs, and third party verification" (IPC-E-04-15 Settlement Stipulation, p 5). However, the Company is no longer required to file the separate annual report specifying ways in which it increased its investment in energy efficiency and DSM as a result of the FCA mechanism. DSM is comprehensively reported in annual DSM reports filed with the Commission.

Potential Changes

The Commission noted when approving the permanent FCA that it "does not isolate or identify changes in cost recovery associated solely with the Company's energy efficiency programs."[16] The Company was required to file a proposal to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. In its compliance filing, IPC recommended making no change to the FCA mechanism, but did propose an altered mechanism in order to comply with the Commission's request. The proposal would cap the annual change in per-customer consumption to two percent (up

16 Order No. 32505, p 6. Available at: http://www.puc.idaho.gov/orders/32599.ord/32505.pdf

or down). The Commission Staff had previously proposed that the FCA balance be equally shared between the customers and the Company in order to account for variations in energy consumption other than weather and energy efficiency. However, the Commission found that neither proposal satisfied its needs, stating that the Company's proposal to cap deviations in annual usage would not have had any effect on previous FCA results. Additionally, both IPC and the Idaho Conservation League filed comments stating that the Staff's 50/50 sharing proposal failed to remove the financial disincentives inherent in DSM programs. The Commission finally determined to keep the FCA mechanism unchanged and continue to monitor the results.

Complementary Policies

Idaho requires its investor-owned utilities to pursue all cost-effective energy efficiency; however, it does not have incentives for achieving energy efficiency savings.

IPC uses inclining block rates as the default rate structure for its residential customers, but there is also available an optional Time-of-Day pilot program with summer and winter peak and off-peak periods. Small general service customers take service on a two-tier, inclining block schedule.

IPC has no filing or reporting requirements relating to service quality (except in Oregon).

Energy Efficiency Outcomes

Before IPC implemented revenue regulation in January 2007, it reported increasing incremental energy efficiency savings from 0 percent of retail load in 2003 to 0.5 percent of retail load in 2006. Since the revenue regulation mechanism was implemented, reported savings have increased from 0.6 percent in 2007 to 1.3 percent in 2010 (with low or no reported savings in 2009 and 2011.)[17] The DSM Report for 2012 shows this to be 1.2 percent.

Resources

Idaho Public Utilities Commission

IPC-E-04-15 - Idaho Power — Investigation of Financial Disincentives

IPC-E-09-28 - Idaho Power — Application to Make the Fixed Cost Adjustment Permanent

IPC-E-11-19 - Idaho Power — Request to Convert Schedule 54 (Fca) From Pilot to Permanent

17 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Maryland: Baltimore Gas and Electric

Baltimore Gas and Electric's (BGE) revenue regulation mechanism compares actual distribution revenue to the authorized revenue, adjusted for the number of customers, for each applicable rate schedule. The authorized revenue, including the cost of power, is based on test year requirements and sales levels. Over- or under-collections are reconciled monthly through a rider. This mechanism differs from the others we describe by having a monthly, rather than annual, deferral and recovery period.

Authority

BGE requested a revenue regulation mechanism in 2007 due to the expected impact on electricity sales of the company's conservation and demand response programs. BGE stated that the revenue regulation mechanism was necessary to eliminate the inherent disincentive in the traditional ratemaking process with respect to conservation and demand response. Under traditional ratemaking, BGE pointed out that, "a one percent reduction in electricity use and demand on the Company's system for the residential and small commercial classes would cut cost recovery by approximately $4 million. This first year impact on recovery is then followed by $8 million in the second year (as an equal amount of savings is added), and so on: the five-year loss to shareholders from this steady-state utility investment program would be more than $20 million"[18] The revenue regulation mechanism proposed by BGE was based on its gas revenue regulation mechanism, which has been in place since 1998.

Authorized Revenue Requirement

BGE initially calculated its revenue requirement per class separately for each rate scale based on weather-normalized 2007 sales and the number of customers. Because BGE proposed the mechanism in 2007, the test year 2007

18 BGE. (2007, October 26). 9111FilingConserva102607F. Available at: http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserva102607F.pdf.

included nine months of actual sales and three months of forecasted sales. BGE used three steps to calculate the base monthly revenue requirement:

1. Calculate the Customer Charge revenues by multiplying the number of customers by the Customer Charge for each class.
2. Calculate the Delivery Service revenues by multiplying the weather-normalized sales by the Delivery Price for each class.
3. Add the Customer Charge revenues and the Delivery Service revenues to determine the base revenue requirements for each class.

BGE's residential, small general service and general service customers are included in the revenue regulation mechanism.

Rate of Return

BGE was allowed a return on common equity of 9.75 percent applied to a common equity ratio of 51.05 percent in its most recent rate case. BGE strongly opposed the reduction of its ROE and preferred another lost revenue mechanism over revenue regulation if an ROE reduction was implemented as a result of revenue regulation.

The Public Service Commission (PSC) made no adjustment to BGE's ROE when revenue regulation was first implemented in 2007, but did reduce its allowed ROE by 50 basis points in the last rate case. The Commission had previously reduced the ROE of another utility by 50 basis points when it adopted a similar revenue regulation mechanism for that utility.[19, 20]

Revenue Adjustment Mechanism

On a monthly basis, the adjustment to base revenue requirement is calculated for each rate class using the following steps:

1. Calculate the revenue adjustment for the change in the number of customers by multiplying the change in the number of customers by the Customer Charge.
2. Calculate the revenue adjustment associated with the change in sales by multiplying the change in the number of customers by the average use per customer and multiplying that product by the Delivery Price for the class.
3. Calculate the target base revenues for each class for the current period by adding the two types of adjustments to the revenue requirement.

The Delivery Price for each class is the delivery rate, established by the PSC, adjusted for the electric universal service charge, nuclear

19 Potomac Electric Power Company.

20 BGE's gas mechanism was approved in a 1998 settlement that did not discuss any adjustment to ROE.

decommissioning credits, and the administrative credit associated with the administrative adder portion of the Standard Offer Service rates.[21]

BGE had a full electric and gas rate case in 2010[22] and another one filed in 2013 and concluded in 2014.[23] Both reset the required decoupling elements—monthly revenue requirement, monthly average usage per customer, and number of customers. Neither case changed the mechanism.

The decoupling mechanism now excludes lost sales resulting from major storms.

Reconciling Actual Revenue With Authorized Revenue

On a monthly basis, each rate class's target base revenues are compared to the actual base revenues for the month. The difference is divided by the forecasted sales for the following period to calculate the monthly rate adjustment. Balancing accounts are used to record the timing differences associated with when the adjustments are calculated versus when they are billed or refunded. The monthly rate adjustment, Rider 25, is capped at ten percent of rates. Any amount beyond ten percent of the current rate will be carried over and reconciled in the subsequent period.

Complementary Policies

Maryland requires its electric utilities to provide energy efficiency services to achieve a ten-percent reduction in per capita electricity use by 2015. The state's overall goal is a 15 percent reduction of per capita electricity use by 2015. Although the PSC is explicitly allowed to approve financial incentive mechanisms to promote energy efficiency, no incentives have been approved yet.[24]

BGE's default service to its standard offer residential customers (those customers who have not elected to take generation service from an alternate supplier) features seasonal rates—summer and winter. BGE also offers a TOU rate as an option to standard offer residential customers and as the default rate for small general service customers.

21 BGE. (2007, October 26). 9111FilingConserva102607F. Available at: http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserva102607F.pdf

22 Case No. 9230 – See references above.

23 Case No. 9326 – See references above.

24 ACEEE. *Maryland.* Available at: http://database.aceee.org/state/maryland

Regarding performance incentives under revenue regulation, in October 2012, Maryland issued a four-part plan designed to speed up investments that will strengthen the state's distribution grid. Part of that plan would set a ratemaking structure that aligns customer and utility incentives by rewarding reliability that exceeds established reliability metrics and penalizing failure to reach those metrics. A task force has encouraged the Maryland state regulatory commission to implement a performance-based ratemaking process for IOUs such as BGE, linking a utility's progress or failure to meet certain reliability metrics with its authorized rate of return.

Energy Efficiency Outcomes

When BGE implemented electric revenue regulation in mid 2007, it had not achieved incremental energy savings for several years. In 2008 it reported incremental savings of 0.5 percent of retail load, increasing to 1.7 percent in 2010 and 2011.[25]

Resources

Maryland Public Service Commission

Letter Order ML 108061 (December 27, 2007)
Letter Orders ML 108069 (November 30, 2007)
- Case No. 9036
  - Order No. 80460 (December 21, 2005)
- Case No. 9230
  - Order No. 83907 (December 13, 2013)
- Case No. 9326
  - Order No. 86060 (December 13, 2013)

25 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Wisconsin: Wisconsin Public Service Corporation

Wisconsin Public Service Corporation's (WPS) Revenue Stabilization Mechanism (RSM) began in 2009 as a four-year revenue regulation pilot that reconciled target marginal revenue per customer with actual marginal revenue per customer. As of 2012, the pilot was extended,[26] albeit with some modifications. This section focuses on the current iteration of the RSM.

Authority

The Public Service Commission of Wisconsin (PSCW) approved a revenue regulation pilot for WPS in a December 2008 rate case order (Docket No. 6690-UR-119). The revenue regulation mechanism was effective from January 1, 2009 through December 31, 2012 and applied to the utility's electric and gas operations. In a rate case completed in December 2012 (Docket No. 6690-UR-121), the pilot was extended, and a modified RSM was approved. The extended RSM is in effect from January 2013 until the next rate case.

Authorized Revenue Requirement

The authorized revenue requirement is determined through a rate case. The Commission uses a future test year to determine the revenue requirement. The cost of fuel is not included in the revenue requirement but is addressed through a "Retail Electric Fuel Rule" adjustment.

Rate of Return

The Commission authorized a rate of return on utility common equity of 10.30 percent in Docket No. 6690-UR-120. This rate remained the same in Docket No. 6690-UR-121 and is currently in effect.

26 The pilot extension is in effect until the effective date of a Final Decision issued by the Commission on an application for a general base rate case filed after January 1, 2013.

Revenue Adjustment Mechanism

WPS implemented a new electric RSM based on a "Total Rate Case Margin" mechanism instead of a "Total Rate Case Margin per Customer" mechanism, which had been the practice during the initial four-year pilot phase. The revision was intended to remove the calculation sensitivities related to sales per customer from the original RSM calculation. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges. The "Total Rate Case Margin" mechanism allows WPS to achieve the total margin assumed in the forecasted test year, no more, and no less. The new RSM will be in effect on a pilot basis until the effective date of WPS's next general rate order, which WPS committed to filing for the 2014 and/or 2015 test years. The RSM applies to most tariffs, except large commercial and industrial customers.[27]

Reconciling Actual Revenue With Authorized Revenue

Each year, the utility compares the total target revenue and the total actual revenue and defers the difference, subject to carrying costs based on WPS's last approved short-term debt rate. The margin will be based on annual per-kWh value established for monitored fuel costs, which is done in a rate case. The margin is determined by subtracting the average kWh value from the authorized energy rates.

The formula for calculating an electric under-recovery or over-recovery is:

Under-recovery or over-recovery equals

$$\sum_{i=1}^{n} \textit{[actual margin minus ratecase forecasted margin established in the most recent rate proceeding]}$$

The summation is over each tariff. A positive value equals an over-recovery, and a negative value equals an under-recovery. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges.

In the event that a true-up will cause rates to increase, the Commission will provide an opportunity for a hearing. Revenue regulation adjustments occur as a part of the general rate case.

27 Except the Direct Load Control, Cp - Large Commercial & Industrial Service, Cp-ND - Pilot Large Commercial & Industrial - Day Ahead, Cp-RR - Large Commercial & Industrial Response Rewards, Automatic Transfer Switch, Parallel Generation, Lighting, Nature Wise, and Real Time Market Pricing tariffs.

The revenue regulation adjustments are subject to a $14 million per year cap for electric, excluding carrying costs. Any adjustments over that amount will not be carried over and will not be collected from ratepayers. Equivalently, revenue over collection in excess of $14 million will not be returned to ratepayers.

Complementary Policies

WPS, like all other investor-owned utilities in Wisconsin, is required to spend 1.2 percent of its annual operating revenues on energy efficiency and customer-owned renewable resource programs that are administered by a third party through the Focus on Energy program, which was established in 2002.[28] Separately, through a contract, the PSCW approves annual electricity savings goals for the Focus on Energy program. The savings goals were equivalent to 0.75 percent of electric sales for the participating utilities from 2011 to 2013. In addition, the PSCW approved a rate of return on investments in energy efficiency for Wisconsin Power & Light, and other utilities can propose incentives as part of their rate cases. However, WPS has not yet proposed an incentive mechanism.[29]

WPS offers residential customers a default flat rate, but they also offer a TOU option with winter and summer on-peak, off-peak, and shoulder tiers. For small commercial and industrial customers, there are flat rates, TOU rates, and critical peak rates. Large commercial and industrial customers can take service under a TOU rate with summer and winter on-peak and off-peak rates, a TOU with critical peak rate, or under a special contract rate unique to the customer and approved by the Commission.

The authorized level of expensed conservation costs recoverable in rates for the test year (2013) is $19,778,728. The level for electric utility operations consists of the conservation budget of $17,669,792, and an escrow adjustment of $2,108,936, which represents the test year amortization of the projected overspent escrow balance at December 31, 2012, over two years.

Wisconsin has a statute requiring filing of reliability data, but no reward or penalty system to support its revenue regulation system.

28 The required spending level was higher for the year 2011 owing to a temporary change in state policy.

29 ACEEE. *Wisconsin.* Available at: http://database.aceee.org/state/wisconsin

Energy Efficiency Outcomes

WPS implemented revenue regulation in 2009. In order to gain approval for the original revenue regulation mechanism, WPS agreed to fund energy efficiency and renewable energy programs at levels above their 1.2-percent statutory minimum contribution to Focus on Energy. Focus on Energy produces an annual report of energy efficiency program activities. In its 2012 report, Focus on Energy reports the following outcomes achieved for WPS' service territory. The table below represents the savings under the statewide Focus on Energy Programs and does not represent the savings attributed under the funding levels above 1.2 percent.[30]

Territory	Utility Type	Segment	Per Capita Lifecycle Bill Savings ($)	Customer Participation Rate (%)	Per Capita Incentive ($)
WPS	Electric	Commercial	$115,258	3%	$83.30
WPS	Electric	Industrial	$9,026,768	96%	$8,924.63
WPS	Electric	Residential	$6,494	36%	$6.66

Resources

Public Service Commission of Wisconsin

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Final Decision. (December 7, 2012). Docket No. 6690-UR-121.

David J. Kyto, Wisconsin Public Service Corporation

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Supplemental Direct Testimony. (May 15, 2012). Docket No. 6690-UR-121.

Focus on Energy

The Cadmus Group, Inc. (2013). Focus on Energy Calendar Year 2012 Evaluation Report: Appendixes. Portland, OR: The Cadmus Group, Inc. Retrieved from http://www.focusonenergy.com/sites/default/files/FOC_XC_CY%2012%20Report%20Appendices%20A-O%20Final%2005-3-13.pdf.

30 The Cadmus Group, Inc. (2013).

Massachusetts: National Grid

The revenue regulation mechanism for National Grid (Massachusetts Electric Company and Nantucket Electric Company together doing business as National Grid) compares authorized distribution revenue to actual distribution revenue. Revenue is compared and adjustments are made separately for each customer class.

Authority

The Massachusetts Department of Public Utilities (DPU) adopted revenue regulation as a statewide regulatory policy in 2008 and individual utilities filed revenue regulation tariffs in response. In its *Investigation Into Rate Structures that will Promote Efficient Deployment of Demand Resources*,[31] the DPU investigated rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in the state and considered how the electric and natural gas distribution companies' existing cost recovery mechanism could be changed to better align the companies' financial incentives with policy objectives while ensuring that the companies are not financially harmed by the increased use of demand resources. The DPU finally concluded that revenue regulation mechanisms would eliminate the financial disincentives because they sever the link between the companies' revenue and reduction in sales. The DPU also endorsed a revenue per customer approach, but recognized that other factors could result in changes to distribution-related costs and consented to consider company-specific ratemaking proposals that accounted for the impact of capital spending and inflationary pressures on the company's required revenue.

31 D.P.U. 07-50. (2007).

Authorized Revenue Requirement

The authorized revenue requirement does not include costs that are reconciled outside of base distribution rates, including energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor.

Rate of Return

The Commission recognized the effects of revenue regulation on ROE, and determined that revenue regulation reduces volatility, which reduces risk, and a downward adjustment to ROE was appropriate, but did not make its actual ROE adjustment for the revenue regulation mechanism explicit in its order.[32] The DPU determined that a return on equity equal to 10.35 percent was sufficient. The testimony from National Grid supporting its proposed ROE presented comparisons of allowed ROE for a set of companies that had revenue regulation or another risk management mechanism in place to account for an implied reduced risk profile in developing that proposal.

Revenue Adjustment Mechanism

Each year the authorized revenue requirement is adjusted to account for capital expenditures in the previous year. The CapEx Adjustment applies to capital expenditures incurred by National Grid for distribution system investments in the previous year, net of the amount recovered through depreciation expense in base rates. This accounts for the material difference in expected capital expenditures compared with prior years. In this way, the CapEx Adjustment in the National Grid revenue regulation mechanism is a special case of a "K Factor," which characterizes an expected change in costs in the future and accounts for those changes when they occur. Each year, the Company files with the Department documentation in support of the capital expenditures it has incurred since the previous review. The Department reviews the filings to determine the prudence of the incremental expenditures and whether the expenditures are used and useful. National Grid then allocates approved expenditures to rate classes based on the cost of service study. For each class, the Company determines the adjustment allocated to the rate class then divides this sum by the forecasted kWh sales for the following year to determine the per-kWh adjustment.

In order to provide a balance between providing the Company with sufficient funds to ensure the safety and reliability of the distribution system and protecting ratepayers against the incentive the Company has to

32 D.P.U. 07-50. (2007). pp 392–396.

overinvest in infrastructure, the mechanism limits the level of annual capital expenditures that is recoverable through the mechanism. To arrive at the amount, the Department set a limit of $170 million per year, which is equal to the approximate three-year average of the Company's capital spending in previous years. Should the Company's capital expenditures exceed this limit, it may seek to include the investment in the rate base during the next base rate proceeding.

The Company submits its CapEx filing no later than July 1 of each year. On November 1 of each year, the Company submits all other information in support of its proposed adjustment factors. The factors will take effect on March 1 of each year.

The authorized revenue is also adjusted to include a 50-percent sharing for earnings above the authorized ROE.

Reconciling Actual Revenue With Authorized Revenue

Each year, National Grid calculates on a rate class-specific basis, the difference between the actual distribution revenue billed to customers through distribution rates and the annual target revenue. For each rate class, the difference between the actual billed distribution revenue and the annual target revenue is summed to determine the Company-wide reconciliation amount. That amount is divided by the Company-wide kWh forecasted for the upcoming year to arrive at a cent-per-kWh reconciliation charge or credit. To determine the final adjustment for each rate class, the Company-wide reconciliation adjustment is added to the rate class-specific adjustment resulting from the target revenue adjustment mechanisms.

The adjustment to the authorized revenue in any year is capped at three percent of total revenues.[33] Any excess can be carried forward to a future year with carrying charges equal to the customer deposit rate.

National Grid must report to the DPU if the difference between the year-to-date billed revenue and year-to-date annual target revenue equals or exceeds ten percent of the target revenue and the Company believes that the difference will fall outside of the ten-percent threshold in the coming months. In this case, interim revenue regulation adjustments can be made. In order to avoid an interim adjustment too close to the scheduled annual rate adjustment, National Grid must notify the Department of variances exceeding ten percent of annual target revenue by August 31 of each year.

33 D.P.U. 07-50. (2007). p 87.

Complementary Policies

Massachusetts requires that electric utilities procure all cost-effective energy efficiency before more expensive supply-side resources. This requirement was translated into annual savings requirements for electric utilities starting from 1 percent of sales in 2009, to 1.4 percent in 2010, 2 percent in 2011, and 2.4 percent in 2012, and potentially increased savings in subsequent years. Utilities can earn approximately five percent of program costs for meeting or exceeding savings targets.[34]

National Grid offers inclining block rates as the default residential rate, but there is an optional TOU rate with peak and off-peak tiers also available to residential customers. Small and large industrial and commercial customers can take service under flat rates, inclining block rates, or TOU rates.

National Grid operates under a penalty and reward system for service quality, established in Docket D.T.E. 99-84. The impetus behind the DPU's original establishment of the Service Quality Guidelines was to prevent Massachusetts utilities from allowing service quality to deteriorate under a new regulatory regime.

Energy Efficiency Outcomes

Before Massachusetts Electric implemented revenue regulation in 2009, it reported consistently high levels of incremental energy efficiency savings, approximately 0.9 percent of retail load. In 2010, the company reported 1.36 percent savings and 1.59 percent in 2010 and 2011, respectively.[35]

Resources

Massachusetts Department of Public Utilities

Docket 09-39

Petition of Massachusetts Electric Company
(November 30, 2009)

34 ACEEE. *Massachusetts*. Available at: http://database.aceee.org/state/massachusetts

35 Personal communication with National Grid.

Hawaii:
Hawaiian Electric Company

Hawaiian Electric Company (HECO) uses a revenue regulation mechanism that compares actual revenue to target revenue in each year. The target revenue is based on the authorized revenue for the last test year adjusted for operation and maintenance (O&M) increases and rate base changes.

HECO is a subsidiary of Hawaiian Electric Industries, which also operates Maui Electric Company (MECO) and Hawaiian Electric Light Company; these subsidiaries service the islands of Maui and Hawaii County, while HECO serves Oahu (Honolulu).

Authority

In 2008, the Governor of Hawaii, the Division of Consumer Advocacy, and HECO entered into an agreement as a result of the Hawaii Clean Energy Initiative.[36] The agreement is intended to move Hawaii away from its dependence on imported fossil fuels for electricity and ground transportation, and toward locally produced renewable energy and energy efficiency. In the agreement, the State, the Consumer Advocate, and HECO committed to, among other things, a transition away from a model that encourages increased electricity usage and to a model that implements revenue regulation decoupling to encourage the development of renewable energy by HECO. The Commission opened Docket 2008-0274 in order to examine the features of a revenue regulation mechanism. The Opening Order directed HECO and the Consumer Advocate to file a joint proposal on revenue regulation within 60 days. This joint proposal was modeled closely after the California mechanism described earlier for PG&E, with a rate-case determined revenue requirement, plus annual attrition adjustments, plus separate mechanisms to recover power supply and energy efficiency costs.

36 Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce & Consumer Affairs, and Hawaiian Electric Companies. Available at: http://files.hawaii.gov/dcca/dca/HCEI/HECI%20Agreement.pdf

The Hawaii Public Utilities Commission approved revenue regulation for HECO in August 2010 based on an investigation into the appropriateness of revenue regulation and its design. The revenue regulation mechanism took effect on March 1, 2011. This replaced a previous lost revenue adjustment mechanism.

Authorized Revenue Requirement

The Commission establishes the Authorized Base Revenues through a general rate case based on traditional cost-of-service ratemaking principles. The Authorized Base Revenue is the annual amount of revenues required for the utility to recover its estimated O&M, depreciation, amortization, and tax expenses for the period.

The Target Revenue is equal to the base revenue requirement less any revenue being separately tracked or recovered through any other surcharge or tracking mechanism, including revenue for fuel and purchased power expenses.

The revenue regulation order also requires staggered triennial rate cases for each of the Hawaiian Electric Industries Companies to determine approved baseline Revenue Adjustment Mechanism (RAM) inputs.

Rate of Return

The Commission made no explicit adjustment to ROE owing to the revenue regulation mechanism, but noted that the allowed ROE of ten percent reflects the approval of revenue regulation and other cost-recovery mechanisms that will lower HECO's business risk.[37] Most recently, the Hawaiian Public Utilities Commission approved a 9.0-percent ROE for MECO, reflecting both a lower baseline cost of capital and a penalty of 0.50 percent associated with inadequate performance bringing renewable energy into the MECO system.[38] A companion Order also established new guidance on future revenue regulation mechanisms.[39]

37 The HECO Companies described as follows in their Reply SOP in the Schedule A decoupling proceedings: "the Commission effectively reduced the Companies' return on common equity by 50 basis points to "fairly compensate ratepayers" for what it perceived as the "risk-reducing" effects of the RBA and RAM mechanisms, the Renewable Energy Infrastructure Program ('REIP") Surcharge and the Purchased Power Adjustment Clause ("PPAC")." Available at: http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A10L29B5532 6B47993

38 Hawaii PUC, Decision and Order No. 31288. (2013, May 31). pp. 97–112.

39 Hawaii PUC, Decision and Order No. 31289. (2013, May 31).

Revenue Adjustment Mechanism

The RAM is designed to replace the need for annual rate cases by adjusting Authorized Base Revenue levels to reflect estimated changes in the utility's cost of service. The RAM is intended to, via formula-driven estimates and escalators, compensate the HECO Companies for changes in utility costs and infrastructure investment between rate cases and reduce the frequency of rate cases. The RAM Period is the calendar year containing the Annual Evaluation Date (March 31, the date of the annual RAM filing). The RAM adjusts the revenue requirement according to changes in four main categories of expenses:

- Base expenses, which are changes in designated O&M expenses;
- Rate base, the return on incremental investment in designated rate base components[40];
- The incremental depreciation and amortization expenses; and
- Exogenous tax changes, changes in costs owing to significant changes in tax laws or tax regulations

Base expenses are segregated between labor and non-labor amounts. The labor component is adjusted annually by the Labor Cost Escalation Rate, reduced by the Labor Productivity Offset (fixed at 0.76 percent). The non-labor component uses the Non-labor Escalation Rate to annually adjust those costs. Tracked O&M expenses for fuel, purchased power, pension and post-employment benefits, integrated resource planning, DSM, and other rate adjustment provisions are not adjusted in the RAM, because any changes in these costs are accounted for in other cost-tracking mechanisms.

The Rate Base equals the average net investment estimated for the RAM Period. The average rate base is the rate base for the rate case test year, with adjustments for changes in only four components of rate base: (1) average plant-in-service, (2) average Accumulated Depreciation, (3) average accumulated contributions in aid of construction, and (4) average accumulated deferred income taxes. All other components of the rate base remain the same as in the preceding rate case test year. The average plant-in-service is equal to the average of the actual plant-in-service at the end of the year prior to the RAM period, the Evaluation Year, and the same year-end balance plus estimated plant additions for the RAM period. Plant additions include Baseline Capital Project plant additions and Major Capital Projects plant additions estimated to be in service by September 30 of the RAM period.

40 Hawaii PUC, Decision and Order No. 31908. (2014, Feb. 1).

The RAM also includes an Earnings Sharing Revenue Credit mechanism in order to protect against excessive overall utility revenue levels. The RAM will escalate and update the Company's approved base revenue requirement, reduced by earnings sharing credits and major project revenue credits to customers. Based on the Company's achieved return on common equity for the Evaluation Year, the mechanism credits the RBAs according to the following chart:

ROE at or below the authorized ROE	**Retained entirely by shareholders, no customer credits**
First 100 basis points (1%) over authorized ROE	25% share credit to customers
Next 200 basis points (2%) over authorized ROE	50% share credit to customers
ROE exceeding 300 basis points (3%) over authorized ROE	90% share credit to customers

Finally, the RAM includes additional consumer protections:

- A provision for Major Capital Projects Credits;
- A provision for Baseline Capital Projects Credits;
- Notification is provided to all affected customers of the RAM filing in newspapers and bills;
- Evaluation procedures for filing, examination, and any exceptions to annual revenue regulation filings;
- Continued ability of HECO or the Consumer Advocate to request formal rate proceedings to replace and terminate RAM at any time; and
- Formal review of revenue regulation as a part of the next round of rate case proceedings;

A recent order[41] added two additional consumer protections:

- A limitation that only 90 percent of the current RAM Period Rate Base that exceeds the Rate Base Adjustment Mechanism from the prior year can be included in the Decoupling Mechanism for baseline utility plant projects, which, unlike major capital projects, are not subject to prior Commission review and approval; and,
- A requirement to post a number of metrics online for customer review, although not at this point tied to performance.

41 February 7, 2014 order on schedule A issues. Available at: http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A14B10B22326F07922. p 42–47.

This order also examined four issues with respect to the application of the RAM. The Commission determined that the short-term debt rate, as reflected in the most recent rate case, should be used to adjust over- and under-collections. The Commission also resolved its concern that, without a sustainable business plan, there exists no strategic framework under which to evaluate capital expenditure programs. The Commission required the parties in the Docket to further explore capital expenditure issues in conjunction with other risk-sharing mechanisms discussed elsewhere in the order. The commission ordered a further evaluation of a proposed risk-sharing mechanism within the RBA. Furthermore, the Commission ordered the parties to work together to establish appropriate metrics, which the utility would report on its website.

Once the total RAM Revenue Adjustment is calculated, it is applied through a uniform adjustment to the per-kWh energy charge for all customer classes.

Reconciling Actual Revenue with Authorized Revenue

RBAs record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA also applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA and recovery of the RAM Revenue Adjustment over the subsequent May 1 through April 30 period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated under the RAM.

On or before March 28, the Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the RBA sub-accounts and the RAM Revenue Adjustment are recovered through the per-kWh RBA rate adjustments. The rate adjustment occurs from May 1 of the current calendar year to April 30 of the next year.

Complementary Policies

Currently, electric utilities in Hawaii may use energy efficiency to meet a portion of their Renewable Portfolio Standard requirements. Starting in 2015, electricity savings from energy efficiency will be applied to the State's Energy Efficiency Portfolio Standard, which sets a target equivalent to 30-percent forecast sales by 2030. This goal is translated into a target of

1.4 percent annual savings. HECO transferred administration of all of its energy efficiency programs to a third party administrator in 2009. The administrator is compensated for satisfactory performance.[42]

Because of its heavy dependence on petroleum as a generation fuel, electricity prices in Hawaii are very high; solar and wind are typically lower-cost resources for these systems. HECO's default residential rates are inclining block rates with a $9.00/month customer charge, and a three-block inclining rate design of $0.34/kWh to $0.37/kWh. Residential customers can elect to

Revenue regulation represents a regulatory framework that removes the financial disincentive for utilities to pursue clean energy strategies. It doesn't, in and of itself, align the utility business model with those utility policies and practices that address customer expectations. In fact, some commissions are concerned that it might create a dynamic in which the utility, assured of its revenue needs, becomes complacent and lacks motivation to innovate and develop strategies that may be more in line with the public interest.

In a recent order (Docket 2011-0092, May 31, 2013) the Hawaiian Public Utilities Commission addressed this big picture issue in a rate order for Maui Electric. The Commission called out the management as lacking a long-term vision for creating customer value and expressed concern that "the HECO Companies' over-reliance upon a link between the [Decoupling] Agreement and utility financial health obfuscates utility performance and ultimately customer service and satisfaction."[43] The implementation of clean energy policies is not a singular goal, but rather a policy that must be part of a larger effort to create customer value.

The Commission laid out a hard path and a soft path to achieve the results they desire for consumers. The hard path involves a closer examination of utility investments, operations, and expenditures. The soft path is opened through the actions of management to create and execute a vision for the utility of the future. The Commission remains committed to regulatory innovations that are in the public interest and will work with the utility, consumer advocate, and other stakeholders to create and implement this vision.

The results of this effort will likely produce ideas and outcomes that will have applicability beyond this one utility.

42 ACEEE. *Hawaii.* Available at: http://database.aceee.org/state/hawaii

43 Hawaii PUC: Decision and Order No. 31288. Maui Electric Company, Limited; Docket No. 2011-0092. (2013, May 31). Appendix C, p 2.

take service under a TOU rate with off-peak, mid-peak, and priority-peak tiers. General service and large power service customers take service under a flat rate, unless they opt to take service under a TOU.

Hawaii is developing reliability standards, in part as a response to deteriorating service quality as a result of distributed and customer-owned generation (see text box). In an effort to make electricity reliability and interconnection standards as transparent as possible, the Reliability Standards Working Group was formed in the Feed-In Tariff docket and continues its work in Docket No. 2011-0206 to find solutions to integrating high penetrations of renewable energy consistent with reliability and power quality standards.

Energy Efficiency Outcomes

HECO implemented revenue regulation in 2011. Since 2003, HECO has reported incremental energy efficiency savings between 0 and 0.5 percent of retail load, with 1.31 percent savings reported in 2011 by Hawaii Energy, the State's ratepayer funded efficiency program administrator. The company has not yet reported its savings for 2012.[44] In addition, HECO has seen more than a sixfold increase in renewable installations under its net metering and feed-in tariff policies since the inception of the revenue regulation plan.

Resources

Hawaii Public Utilities Commission

Docket No. 2008-0274
Final Decision and Order (August 31, 2010)
Docket No. 2008-0083
Final Decision and Order (December 29, 2010)
Docket No. 2011-0092
Final Decision and Order May 31, 2013, including Decision and Orders Nos. 31288 and 31289
Docket No. 2013-0141
Final Decision and Order (February 1, 2014), including Decision and Order No. 31908.

44 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Discussion of the Six Utilities Overall

Authority

The first step in implementing a revenue regulation mechanism is to understand the authority of the regulating body: the Public Utility Commission or PSC. It is important for any Commission to clarify its justification for acting on revenue regulation in order to prevent any decisions from being overturned. Over the years, Utilities Commissions have relied on different justifications for implementing revenue regulation mechanisms. Commissions have implemented revenue regulation at their own discretion, justified by their directive to ensure safe, reliable, and economic public utility service to citizens to justify changing the regulatory environment. In some cases, the Commission is unable to engage on narrow issue ratemaking and rates can change only as the result of a full rate case. In this case, statutes must be amended to enable revenue regulation.

In all of the case studies discussed here, the Commissions first implemented revenue regulation at their own discretion, but each followed slightly different paths to do so. The CPUC first implemented revenue regulation in 1978 at its discretion. In 2001, after a period when mechanisms were suspended, the California Legislature required that deviations from projected sales not result in under- or over-collections by utilities, and so the CPUC re-implemented revenue regulation according to statutory requirement. The Hawaii Public Utilities Commission implemented revenue regulation after an agreement between the utility, the Governor, and other stakeholders called for it. In Idaho, the Commission established a case in which to investigate revenue regulation and held a series of stakeholder workshops before implementing the policy. The Massachusetts DPU adopted revenue regulation as a statewide regulatory policy and required individual utilities to file tariffs in response as the result of its general investigation into rate structures that promote demand-side resources. The Maryland Commission implemented revenue regulation for BGE when the utility requested the mechanism. Thus the impetus to develop a revenue regulation mechanism may come from different sources and the Commission may be comfortable in moving forward under their general supervisory statutes.

Nevertheless, specific statutory language can be helpful to shore up the existing authority.

Authorized Revenue Requirement

Under the traditional regulatory framework, the Commission (or other authority in the case of publicly owned utilities) must determine a utility's revenue requirement. This function does not change under revenue regulation. The revenue requirement of a utility is the aggregate of all the operating and other costs incurred to provide service to the public. This typically includes operating expenses, depreciation, and the cost of capital invested, including interest on debt and a "fair" return on equity to investors. The (simplistic) formula for determining revenue requirements is as follows:

$$\textit{Revenue Requirements} = (\textit{Rate Base} \times \textit{Rate of Return}) + \textit{Operating Expenses} + \textit{Depreciation} + \textit{Taxes}$$

Traditionally, the revenue requirement, along with sales, is used to determine the rates consumers will pay for electricity.[45] The rates are also broken down by customer class, and intraclass tariffs are created based usually on a cost of service study that determines each customer class and subclass contribution to the utility's costs. The (simplistic) formula for determining the rate per unit is:

$$\textit{Rate} = \textit{Revenue Requirement} \div \textit{Units Sold}$$

In this way, rates are set to allow the utility to exactly recover its revenue requirement when the sales level used to calculate rates is equal to actual sales. However, it is important to recognize that actual expense and revenue varies with actual sales. When actual sales are greater than the sales level used in ratemaking, revenue increases and expenses increase by a different amount; when actual sales are lower than the ratemaking sales level, actual revenue declines and expenses decrease by a different amount. Under revenue regulation, rates are initially set in the same way, but when actual sales differ from the level used to calculate rates, the actual revenue level is maintained at the rate case amount as rates are allowed to vary inversely with sales—increased sales lead to decreased rates and vice versa. Because the primary expenses that change in the short run as sales levels change are power supply expenses, and most regulators allow these to be tracked using a power cost adjustment mechanism, revenue regulation mechanisms are generally designed to ensure recovery of the non-power costs (which do not change significantly in the short-run) as sales volumes change.

45 Lazar et al., 2011.

Revenue regulation ensures that actual revenue is equal to the revenue requirement established by the Commission or appropriate authority. Although the description above presents an overly simplified view of the revenue requirement and its use in traditional price regulation and revenue regulation, there are many variations on how a Commission can establish a revenue requirement, particularly when implementing revenue regulation. With revenue regulation, as in traditional ratemaking, imprudent costs can always be removed from rates, and there is no change to the ability of a Commission to impose penalties.

Utility Functions to be Included

First, the regulator must determine which utility functions will be included in the revenue regulation framework. With vertically integrated utilities, this usually includes a utility's regulated generation, transmission, and distribution units. As we discuss below, however, it is critical to structure power supply recovery mechanisms to avoid providing for double-recovery of certain power supply costs. For utilities operating in areas of the country that have restructured electricity markets, only the regulated distribution business is decoupled. Utilities that also provide gas services may have their gas distribution business operating under revenue regulation as well.

Table 1

Business Unit Included in the Revenue Regulation Model	
Pacific Gas & Electric	*Electric generation and distribution; gas distribution*
Idaho Power Company	*Electric generation and distribution*
Baltimore Gas & Electric	*Electric distribution; gas distribution*
Wisconsin Public Service Corporation	*Electric generation and distribution*
National Grid	*Electric distribution*
Hawaiian Electric Company	*Electric generation and distribution*

Test Year

One consideration in establishing the revenue requirement is what period of time will be used as a "test period" or "test year." The test year is the year on which the Commission will base its computations of the utility's total costs and sales levels. A historic test year uses actual data on sales and costs from

Table 2

Test Year Used	
Pacific Gas & Electric	*Future test year*
Idaho Power Company	*Historic test year*
Baltimore Gas & Electric	*Hybrid test year*
Wisconsin Public Service Corporation	*Future test year*
National Grid	*Historic test year*
Hawaiian Electric Company	*Future test year*

a past year. Whereas a historic test year allows for the use of actual cost data, it cannot account for expected variations in sales. A future test year requires assumptions to be made about a utility's sales in a future year. This can allow expected changes in sales, like those from energy efficiency programs, to be included in sales projections: however, because regulators are relying on estimates provided by the utility, there may be a greater risk for inaccuracy. A Commission may also choose to use a test year that includes both past and future periods. This may provide a sense of balance between historic and future data. Furthermore, as the case proceeds, the Commission can require the utility to substitute historical data for projected data from the test year.

Rate of Return

As in any rate case, regulators must determine the appropriate rate of return that a utility can earn on its investments, including the cost of debt and the allowed ROE for its shareholders. The approved ROE is only used to establish the return on investments that are included in the rate base when determining revenue requirements. Although revenue regulation ensures that a utility recovers no more or less than its target revenue, revenue regulation does not guarantee that the utility will earn the authorized ROE. Depending on how a utility manages its costs between rate cases, it will realize an actual ROE either higher (in the case of reduced costs) or lower (in the case of increased costs) than the authorized level.[46]

46 In a rate case, the Commission determines an allowed return on equity. This is used to set a price (price regulation) or an allowed revenue requirement (revenue regulation). Once set, however, the actual return earned by the utility is affected by anything that changes either revenue or expenses; for example, an increase in employee compensation, a change in the number of employees, or, under price regulation, a change in sales volumes.

A utility's allowed ROE generally represents the return deemed necessary to attract investment considering the level of risk of that investment. Riskier investments require a higher return to attract investors and vice versa. Utility earnings can be volatile because of short-run impacts on sales volumes and revenues, which include changes in sales owing to weather, economic conditions, and energy efficiency and DG programs. This volatility typically causes utilities to retain a higher level of equity in their capital structures so that reduced revenues do not leave them unable to service their debt. Revenue regulation can reduce this volatility by stabilizing revenues regardless of the cause. Because of this reduced risk, many stakeholders have proposed that the implementation of a revenue regulation mechanism be associated with a corresponding reduction in the utility's equity capital ratio (the percentage of capital supplied by common equity). This reflects the utility's more stable revenue owing to revenue regulation and reduces the overall revenue requirement that will be recovered from consumers.[47]

An alternative option to reducing the utility's equity ratio is to reduce the ROE, reflecting a lower risk level. For the utilities included in these case studies, only BGE and Mass Electric experienced a reduction in their ROE. The Commission did not reduce BGE's ROE at the time the revenue regulation mechanism was implemented, but reduced it by 50 basis points during the subsequent rate case. The Massachusetts Commission did not reveal its adjustment, but incorporated a lowered ROE into its decision.

Absent an explicit adjustment to the cost of capital, investors' expectations will adjust to the presence of revenue regulation if its presence is reliable. The more stable earnings will likely, in time, contribute to a higher credit rating. That in turn will lead to lower cost debt that will be revealed in future cost of capital calculations. An adjustment to the ROE or capital structure by the regulator in a rate proceeding will be reflected immediately in lower rates to consumers; simply allowing the utility's credit rating to improve over time, and its cost of debt to decline, will have the same effect, but on a lagged basis, as new bonds are issued at lower interest rates.[48]

Beginning in 2004, Standard and Poor's began publishing "risk profiles" for utilities, which classified utilities based on their earnings variability and other risks; those with more stable earnings were determined eligible for higher bond ratings at any given equity capitalization ratio (or, alternatively, able to retain a given bond rating with a lower equity ratio).[49] One utility

47 Lazar et al., 2011.

48 Lazar et al., 2011.

49 Standard and Poor's. (2004, June 2). *New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised.*

with a revenue regulation mechanism, Northwest Natural Gas, was believed to have had their business risk profile upgraded by one step in response to the benefits of the mechanism.[50]

Effect on Bond Ratings

Revenue regulation stabilizes a utility's revenue streams, reducing risk to investors; this reduced risk may be a contributing factor in an increase in a utility's bond rating. Bond rating agencies have recognized that revenue regulation mechanisms and other mechanisms that reduce net earnings volatility and risk contribute to a lower cost of capital for the utility.[51] Standard and Poor's has explicitly stated that it "views decoupling as a positive development from a credit perspective."[52] However, in the case of the utilities examined in this report, none experienced an improved credit rating after the implementation of revenue regulation with the exception of PG&E. However, PG&E came out of Chapter 11 bankruptcy in the same year that its revenue regulation mechanism was implemented, making it impossible to attribute the improvement to revenue regulation alone. Bond rating changes are generally slow to evolve. Numerous other factors are taken into account when assigning an overall credit rating, which appear to have outweighed any positive effect of revenue regulation. These factors certainly include the recession of the U.S. economy that began in 2007.

Customer Classes Included

When determining the target revenue for a utility revenue regulation mechanism, regulators must also consider which customer classes to include in the mechanism. In some cases, industrial customers have objected to a revenue regulation mechanism. This is due to the wide difference in rates among customers, making the design of a revenue regulation mechanism more challenging. If regulators choose to exclude a class of customers from revenue regulation, they must determine the revenue requirement associated with serving only the included customer classes. This generally requires a detailed cost of service study to ensure that revenue responsibility is accurately allocated by customer class.

50 Christensen Associates. (2005, March). *A review of distribution margin normalization as approved by the Oregon Public Utility Commission for Northwest Natural.*

51 Lazar et al., 2011.

52 Standard & Poor's. (2008, February 19). *Decoupling: the vehicle for energy conservation?*

Table 3

Customer Classes Included in Revenue Regulation Mechanism	
Pacific Gas & Electric	*All customer classes*
Idaho Power Company	*Residential and small general service*
Baltimore Gas & Electric	*Residential and small general service*
Wisconsin Public Service Corporation	*All customer classes*
National Grid	*All customer classes*
Hawaiian Electric Company	*All customer classes*

Included Costs

Finally, regulators may wish to exclude specific costs from the overall revenue requirement if those costs will be tracked through another mechanism, like fuel costs in a PCA mechanism, energy efficiency program expenditures, or smart grid costs, for example. Separate tracking mechanisms can also be used for those costs that are difficult to project based on historical data or costs over which the utility has very little control, like fuel costs. Although revenue regulation tracks collected revenue, mechanisms like Fuel Adjustment Clauses, Purchased Power Adjustments, and Energy Efficiency Riders can be designed to track actual costs as well as collected revenue.

This topic raises a note of caution: if mechanisms are not well designed, double-recovery of costs can occur for vertically integrated utilities that provide both power supply and distribution services. For example, if a per-customer revenue regulation mechanism includes investment-related power supply costs in the revenue-per-customer formula, but excludes fuel and purchased power costs that are recovered through a separate tracking mechanism, double recovery of some power supply costs is likely. If the utility experiences customer and sales growth, the amount it recovers for investment-related power supply costs will go up. However, if that utility serves this growth by operating existing power plants more, by selling less power on the surplus market, or by purchasing power from other suppliers, it will not incur any increases in the type of power supply costs accounted for in the revenue per customer (RPC) calculation. The increased power supply costs to serve that growth will be recovered through the fuel and purchased power tracking mechanism. The net effect for the utility will be to recover incremental power supply costs twice—once in the per-customer mechanism, and again in the fuel and purchased power mechanism. It is essential to make sure that the other adjustment mechanisms do not overlap the cost impacts

Table 4

Costs Excluded From Revenue Regulation Mechanism	
Pacific Gas & Electric	*Energy procurement costs*
Idaho Power Company	*All variable costs*
Baltimore Gas & Electric	*Energy supply costs*
Wisconsin Public Service Corporation	*Energy costs*
National Grid	*Energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor*
Hawaiian Electric Company	*Fuel and purchased power*

that are treated in the revenue regulation mechanism. One way to do this is to ensure that all power supply costs (investment, labor, fuel, purchased power) are recovered through a single mechanism. There are several ways to achieve this:

a) A comprehensive power supply recovery mechanism that includes all power supply costs, that is separate from the costs treated in the revenue regulation adjustment (e.g., Puget Sound Energy, Washington State)
b) No power supply adjustment whatsoever, with all utility costs included in an RPC mechanism (e.g., National Grid)
c) An annual attrition calculation, with all costs reviewed for changes since the last proceeding (e.g., HECO)

Revenue Adjustment Mechanism in Revenue Regulation

A RAM[53] is not necessary to achieve revenue regulation, but provides attrition relief—increasing authorized revenue commensurate with increased costs—between rate cases. Whereas revenue regulation sets a target revenue that the utility will earn regardless of sales levels, the RAM adjusts the target

53 We use the RAM term applied in Hawaii here to address any type of attrition or similar mechanism, other than a revenue-per-customer framework, that changes the allowed revenue between general rate cases.

Table 5

Type of Revenue Adjustment Mechanism	
Pacific Gas & Electric	*Hybrid*
Idaho Power Company	*RPC*
Baltimore Gas & Electric	*RPC*
Wisconsin Public Service Corporation	*RPC*
National Grid	*No RAM; potential capital expenditure adjustment*
Hawaiian Electric Company	*Hybrid*

revenue between rate cases. Regulators may choose to take several different approaches to RAM:

- **No RAM.** Regulators may choose not to implement a RAM, leaving the revenue requirement unchanged between rate cases. This requires the utility to request a rate case when it requires additional revenue to cover its costs.
- **Stairstep.** Stairstep adjustments provide predetermined increases in target revenue. These increases can be determined during a rate case and generally reflect forecasts of cost growth.
- **Indexing.** Indexing ties adjustments to the target revenue to multiple factors like inflation, productivity, customer growth, and changes in capital expenditures.
- **RPC.** The RPC approach is a form of indexing. RPC adjusts the total revenue requirement for the number of customers served. Regulators using an RPC mechanism will determine the revenue requirement per customer and the overall revenue requirement will be determined by multiplying the total number of customers by the revenue requirement per customer. The amount of revenue required to serve each customer can be determined separately for customer classes and for existing and new customers. This way, the RPC method accounts for a utility's growth in fixed costs that is related to growth in the number of customers served. RPC is useful where the correlation between cost growth and customer growth is significant. It also protects customers from making up the deficit if there is a loss in customer load, such as if a large business closes down or relocates.
- **Hybrid.** Hybrid RAMs generally use stairstep increases to account for projected capital costs and indexing to account for O&M expenses.

Adjustments from any type of RAM can be implemented automatically or through an attrition proceeding. Some stakeholders oppose adjustments to the revenue requirement outside of a rate case on the basis that this could allow the revenue requirement to increase significantly without examination of the impact on ratepayers or without due consideration of other costs and revenues. For this reason, some regulators choose to cap the total adjustment that can be made to the revenue requirement outside of a rate case.

Calculation of Actual Revenue

Regulators have options when ensuring that actual revenue equals target revenue under revenue regulation. First, regulators must decide how to determine "actual revenue." In most cases, actual revenue simply equals the amount of revenue a utility collects from its customers. The Idaho Public Utilities Commission, however, has chosen to use weather-normalized revenues as the basis for utility revenues in revenue regulation. Although this prevents the utility from recovering revenue lost to it owing to milder than expected weather, it further complicates the revenue regulation mechanism and reduces its risk-reduction benefits. By the same token, if weather is severe and increases sales above the revenue requirements, weather normalization would allow the utility to retain some of the revenues.

Next, regulators must determine whether to implement revenue regulation using a current or accrual method.

- **Current Method.** With the current method of revenue regulation, the target revenue for a period, say a month, is divided by the actual sales in that period to determine the rate per kWh. The current method ensures that actual revenue equals target revenue by calculating the rate at the end of the period so that the target revenue can be recovered. The current method allows for no lag in revenue recovery. One effect of this method is that, although customer rates vary, total bills are generally more stable. For example, in a hotter than expected July, customers will purchase more kWh, but they will be charged a lower rate. A milder than average winter would lead to fewer sales, but at slightly increased rates. This way, customers do not experience the same bill variability as they would if rates were set before the sales deviations occurred. On the other hand, the current method does not provide customers with the ability to plan ahead based on a predictable rate for electricity. This method has been used for revenue regulation of natural gas utilities.[54]

54 Because this method results in changes in the price for service that are calculated after that service has been provided, it fails the "no retroactive ratemaking" statutes that guide most electricity regulators. Customers are entitled to know the price of the commodity they are consuming at the time they use it.

Table 6

Tracking and Accrual of Difference Between Actual and Authorized Revenue		
	Track Difference	**Accrual Period**
Pacific Gas & Electric	*Monthly*	*Year*
Idaho Power Company	*Monthly*	*Year*
Baltimore Gas & Electric	*Monthly*	*Month*
Wisconsin Public Service Corporation	*Yearly*	*Year*
National Grid	*Yearly*	*Year*
Hawaiian Electric Company	*Monthly*	*Year*

- **Accrual Method.** Under the accrual method, rates are set based on an assumed sales level and the differences between actual and target revenue are allowed to accrue over some period. Then the total difference between actual and target revenue is reconciled through an adjustment to rates in the subsequent period; this is known as the true-up process. Presently all revenue regulation mechanisms for electric utilities use the accrual method.[55]

If regulators use the accrual method of revenue regulation, they will next need to determine the period over which the difference between actual and target revenue will be allowed to accrue. One year is typical; however, shorter periods are also used. Next the frequency of comparing collected revenue to target revenue should be determined. It is possible to do this comparison only once at the end of the accrual period. It is common, however, for comparisons to occur more frequently, often monthly. When revenues are compared within the accrual period, the differences are tracked, generally for the purpose of applying interest to the difference that will be deferred until the end of the accrual period.

Rate Adjustments

In designing a revenue regulation mechanism, there are a number of decision points that regulators need to consider to balance the interests of all the stakeholders. One of the decision points revolves around the

55 The closest to a current method in use for electric utilities in the BGE system of monthly reconciliation.

determination of the mechanism used to adjust rates. The issues that regulators need to consider include the following:

1. **Rate Case Requirements.** One of the often-mentioned concerns about surcharges, especially when they are numerous, is how that will impact the frequency of rate cases. For regulators and stakeholders, rate cases provide the best mechanism to correctly align rates and costs, but they are time-consuming and expensive for all parties. This is because a rate case presents an opportunity to closely examine all of the utility's expenses and adjust rates to reflect cost increases and decreases. Because under a revenue regulation mechanism the goal is to match revenues received from all customers with revenue requirements, a correct determination of revenue requirements is important, as is the specification of appropriate cost indices to adjust the revenue requirements. As the time between rate cases increases, some regulators feel the base rate case data, even with adjustments, need to be reexamined. As a result, some regulators have chosen to mandate the frequency of rate cases to address this, whereas others have not. It may be that in some cases, where there are numerous surcharges recovering a multitude of costs, there may not be as many costs subject to review in the rate case, making it less significant to a regulator than a case in which most costs are being analyzed and recovered in the rate case itself.
2. **Collection Mechanism.** Integrally tied to the mechanism for recovering revenues is how the utility will collect or refund the revenues. Options that are available include recovery through a rate case or periodic adjustments to rates through a surcharge mechanism. As can be seen by the case studies, depending on the plan in place, some utilities have very discreet requirements dictating the frequency of rate cases with adjustments occurring in those cases or between those cases. Other utilities have no requirements upon them with respect to the frequency of rate case filings. This will be discussed in more detail below. What does emerge from these case studies is that the discreet components or choices in how to execute a revenue regulation plan are carefully interwoven to create a holistic approach. Each component works with the other and the value of this case study is in examining the different pathways that can be chosen. As discussed previously, some of the commissions have authorized revenue regulation to recover the revenue requirements in the last rate case, whereas others have authorized adjustments to rates between rate cases; this impacts the pathway that the adjustment mechanism takes.
3. **Timing.** How often should rates be adjusted to true up to the utility's revenue requirement. States have chosen different options ranging from monthly to annually.

4. **Allocation of Revenue Regulation Revenue Surpluses or Deficits.** There are a number of decision points regarding allocation. Should the revenue regulation apply to all rate classes or just the smaller customers whose usage per customer and load variations are not as dramatic as those of larger-use customer classes? Should there be a different allocation to each rate class or should the allocation of costs among the classes be the same? Different mechanisms accomplish different goals. Some states have allocated revenue regulation revenues based on the revenues lost by customer class as a result of energy efficiency. This can sometimes be a political decision to mitigate opposition to energy efficiency programs by large customers. Other states recognize that the system savings resulting from energy efficiency benefit all customers, so that all customers should pay equally.
5. **Carrying Charges.** Depending on the timing issue discussed previously, regulators may want to consider carrying charges on any adjustments. This should be symmetrical in its application, however, so that it applies to surcharges and refunds. Consideration should be given for the basis of the carrying charge rate, whether weighted average cost of capital, rate of return, a risk-free rate, or some other mechanism should be adopted.
6. **Rate Caps.** In order to mitigate potential rate impacts, a regulator may want to consider a cap on how much rates can go up when the revenue regulation adjustment is made. This might be more critical if the regulator is aware of other potential rate increases that will impact customers' bills. If a cap is used, the case in which the utility's adjustment would exceed the cap must be considered. Some regulators have opted to allow the utility to carry over the excess unrecovered amount for a period of years, whereas others do not. This allows the utility to recover those revenues in a subsequent year when perhaps the adjustment is less. As a practical matter however, adjustments of greater than three percent are less common, as shall be discussed later.
7. **Impact on At-Risk Consumers.** Low-income and consumer advocates have expressed concern about revenue regulation as a vehicle for annual rate increases without the scrutiny of a general rate case, creating rate increases for the low-use customers doing the most to constrain usage and help achieve targeted energy savings. One proposal to address this has been to impose any resulting surcharges only to above-average usage customers, and any resulting credits only to below-average usage.[56]

56 Cavanagh and Howat. (2012, May 2). Finding common ground between consumer and environmental advocates. *Electricity Policy.*

Rate Case Requirement

Requirements as to the frequency of rate cases can be tied to the recovery mechanism or to the entire regulatory framework for implementing revenue regulation. In the cases studied, two of the utilities require periodic rate cases: PG&E every three years and WPS every year. Two others, National Grid and HECO, require annual mini rate cases, explained later, in which adjustments are made, and two others, IPC and BGE, have no requirements for scheduled rate cases. Nevertheless, if the concern is to ensure that the utility's revenue recovery meets its revenue requirements, some kind of periodic rate case to examine costs is appropriate. Having periodic rate cases can provide a measure of assurance to consumer advocates that the level at which the revenues, and hence the rates, are set, is correct. One of the criticisms of revenue regulation is in fact the lack of rate cases to produce a proper level of confidence in the allowed amounts. Multiple surcharges are usually additive to existing rates, therefore not permitting an opportunity to reduce the base rate for reductions in cost. Moreover, the infrequency in cases impedes the examination of rate allocations as would occur through a cost of service study.

This is a particular issue where utilities are augmenting power supply with purchased power from independent power producers, which is the most common method for acquiring wind and solar production today. The increased cost for purchased power may flow through a fuel and purchased power adjustment mechanism, while the (depreciating) investment in conventional power plants remains static in base rates.

Both PG&E and WPS use a future test year that allows the utility to project revenue requirements during the time period that the rates are to be in effect. The benefit to this is that it can help identify and account for projected changes in costs over the timeframe between rate cases. However, given that these costs are utility projections, most consumer advocates have less confidence in these numbers than they would using actual numbers from a historical or only hybrid test year.[57] When trying to garner support for revenue regulation from more skeptical stakeholders, using a future test year may not be helpful. Furthermore, in the case of WPS that has annual rate cases, using a future test year becomes less justifiable, as revenues are recalculated annually anyway.

57 The most common criticism of future test years is that utilities forecast costs under an assumption that all authorized personnel positions will be filled, while in retrospect, any large organization has some level of vacancy in its employee count. A historic test year captures this effect fully.

The absence of a rate case requirement can also cause consternation among detractors of revenue regulation because of the belief that the utility will be guaranteed its revenue requirements for as long as it is satisfied with that level, irrespective of how well it manages. However, this is no different from the status quo in traditional regulation in most places. The incentive to manage well is always there with or without revenue regulation as it translates into more profit for the utility.

In the cases of HECO and National Grid, the mini rate cases serve two purposes. In the one instance, it serves as a means to reconcile revenue recovery with revenue requirements, and in the second instance, it provides an opportunity to adjust rates in accordance with changes in costs. Specifically, for National Grid, the revenue requirement is adjusted to reflect capital expenditures. For HECO, revenues are adjusted to reflect changes in the cost of service. In the two examples here, revenue regulation is wrapped in with other adjustments as part of a mini adjustment. Given the structure for determining revenue requirements, which accounts for changes in costs, including revenue regulation within the mini rate cases is a workable option.

These examples highlight how rate cases can be used to adjust revenue requirements either in a more controlled regulatory environment with frequent rate cases or left to the utility's discretion to decide when to adjust costs. A set schedule of periodic rate cases, such as that used by PG&E, may strike an appropriate balance for reviewing revenue requirements, however, with the modification of a partial historical partial forecasted test year. Frequent rate cases can, depending on the resources of the regulator and stakeholders, be too costly and time-intensive. When there are too many rate cases, stakeholders and regulators may not be able to dedicate the level of resources needed for any one proceeding and may be spread too thin. Regular known rate cases at reasonable intervals may strike the best balance of adequate review and adjustment of revenue requirements.

Collection Mechanism and Timing

The collection mechanism for the differential between actual and authorized revenue requirements varies by utility as well. Both PG&E and WPS do not have adjustment clauses or surcharges, but instead have structured their revenue regulation plans to recover their costs in a rate case with rates adjusted annually. Although PG&E has rate cases every three years, the utility files its preliminary forecast every September 1 for the following year, including adjustments for revenue regulation and other costs. This practice promotes transparency, keeping all stakeholders aware of the current situation of the utility. IPC, BGE, National Grid, and HECO use surcharges on customer bills to collect or credit the difference between actual revenues collected and the revenue requirement. Although the other three (IPC,

Table 7

Rate Case Requirements	
Pacific Gas & Electric	*Every three years; annual "attrition" adjustments in between*
Idaho Power Company	*No requirement*
Baltimore Gas & Electric	*No requirement*
Wisconsin Public Service Corporation	*Annual rate case*
National Grid	*Annual capital expenditure adjustment case*
Hawaiian Electric Company	*Abbreviated annual rate case*

National Grid, and HECO) calculate the rate adjustment annually, only BGE does a more contemporaneous adjustment of one month. Certainly where there are no regularly scheduled rate cases, using an adjustment mechanism becomes more critical. PG&E has created a tracking mechanism known as a balancing account that allows the utility to track the surpluses and deficits to help ensure accuracy at year end when rates are actually adjusted. The creation of such monthly balancing accounts will make it easier at the end of the year to track what happened each month and then determine the adjustment for that year. It provides a more detailed trail for review and analysis by stakeholders and regulators. However, other mechanisms that just look at total revenues as compared to revenue requirements at the end of the year can work as well.

Table 8

Rate Adjustments	
Pacific Gas & Electric	*Base rates adjusted annually*
Idaho Power Company	*Annual adjustment through surcharge*
Baltimore Gas & Electric	*Monthly adjustment through surcharge*
Wisconsin Public Service Corporation	*Annual adjustment through rate case*
National Grid	*Annual adjustment*
Hawaiian Electric Company	*Annual adjustment*

Table 9

Allocation of Surplus or Deficit	
Pacific Gas & Electric	*Allocated to all customers according to business unit (e.g., electric distribution, electric generation)*
Idaho Power Company	*Included in the annual adjustment mechanism for each customer class*
Baltimore Gas & Electric	*Separate for each customer class*
Wisconsin Public Service Corporation	*Allocated to all customers, except certain tariffs (see above)*
National Grid	*Separate for each customer class*
Hawaiian Electric Company	*Separate for residential and commercial/ industrial*

Allocation of Revenue Regulation Revenue Surpluses or Deficits

The allocation of revenue regulation revenue surpluses or deficits should be symmetrical so that overpayments are credited to customers just as underpayments are paid by those same customers. The six utilities studied follow that formula. The application of revenue regulation, however, varies from utility to utility. BGE and IPC apply revenue regulation to the residential and commercial classes, thereby excluding industrial customers. In contrast, however, PG&E, WPS, National Grid, and HECO allocate revenue regulation adjustments to all customer classes. In terms of how the costs are allocated, IPC, BGE, WPS, National Grid, and HECO allocate costs differently among the customer classes. PG&E, however, allocates costs uniformly among the customers. Because PG&E has separated its business units, it also separately calculates and allocates revenue regulation surpluses and deficits among its electric distribution, gas distribution, and electric generation businesses. This illustrates that there are several ways to address revenues from revenue regulation depending on the policy outcomes that are desired.

Carrying Charges

Carrying charges applied to uncollected or surplus revenues can be used to account for the time value of money and the lost opportunity or value to having those revenues in hand. PG&E and BGE do not accrue carrying charges. On the other hand, IPC, WPS, National Grid, and HECO do. For

Table 10

Carrying Charges	
Pacific Gas & Electric	*None*
Idaho Power Company	*Yes*
Baltimore Gas & Electric	*None*
Wisconsin Public Service Corporation	*Yes, at the short-term debt rate*
National Grid	*Yes, at the customer deposit rate*
Hawaiian Electric Company	*Yes, at the customer deposit rate*

BGE, given that the revenue regulation revenues are reconciled and recovered monthly, it would make little sense to include a carrying cost. Where carrying costs have been used, they have included in the cases of these utilities the short-term debt rate or the customer deposit rate, which for one utility is six percent and probably close to the short-term debt rate. Thus, the carrying charge rates are appropriately at the lower end of the spectrum reflecting their short-term nature. In the application of the carrying charge, symmetry should be preserved by applying it to both deficits and surpluses. Application of carrying charges given the short period that costs are carried (one year) is somewhat discretionary. Although it does more accurately account for costs, it does add a modest level of complication in tracking costs.

Rate Caps and Collars

One of the ways to protect customers in the event of significant adjustments is to impose a rate cap (or collar) that limits the amount of a rate increase (and decrease). Some customers are sensitive to changes in foundational costs like utility bills and if costs are going to rise, they benefit from a pattern of steady modest increases rather than a large step increase. Any structural increases in rates attributable to reductions in sales or increases in costs recognized by the revenue regulation plan would be eventually included in rates under any system. A cap reflects a controlled way to manage customer expectations and customer impacts. Structural changes can only be managed for a while until a complete rate case is needed to reset all assumptions.

Typically, when a rate cap is imposed, if the formulaic increase exceeds the cap or collar, the utility will be able to carry over any uncollected revenues until the next rate adjustment. Two of the utilities studied, PG&E and HECO, do not have rate caps. On the other hand, the other four utilities do include

Table 11

Cap on Rate Adjustment	
Pacific Gas & Electric	*No*
Idaho Power Company	*3% rate cap; excess carried over to next period*
Baltimore Gas & Electric	*10% rate cap; excess carried over to next period*
Wisconsin Public Service Corporation	*Cap of $14 million per year*
National Grid	*$170 million in CapEx*
Hawaiian Electric Company	*No*

rate caps in varying amounts. National Grid has a one-percent revenue cap, whereas IPC and BGE have a one-percent and a ten-percent rate cap, respectively. WPS, unlike the others, has a cap tied to the dollar amount of $14 million as opposed to a percentage. Consistent with the goals of revenue regulation, all of the utilities studied have a carryover provision that is important for reducing the risk that the utility will not recover its revenue requirements.

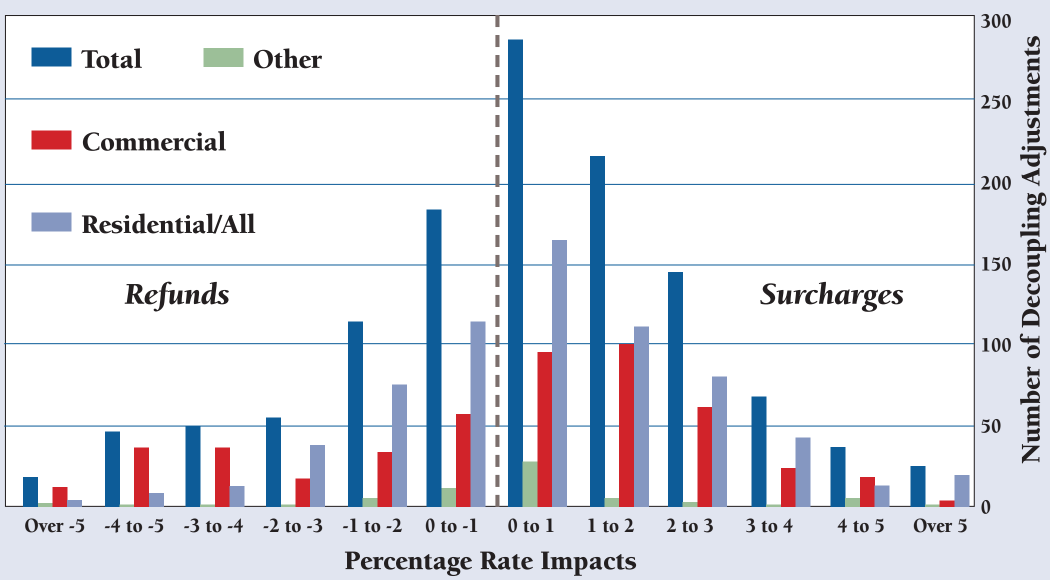
Note that National Grid differs from BGE and HECO in that its cap is on revenues, whereas the other two utilities cap rates and rate impacts. A revenue cap is more focused on ensuring minimal change to the revenue requirements authorized by the commission. National Grid, as discussed previously, allows for mini rate cases to adjust the revenue requirements. Having the one-percent cap limits the amount of increase that can occur through that process, requiring revenue changes that are greater to occur in a full rate case. However, note also that some of the adjustments allowed in the mini rate case have their own separate cap. The IPC rate cap is in line with what many other utilities with caps have in place, which generally range from one to three percent. The ten-percent rate cap in the BGE plan is reflective of its monthly adjustment pattern. An annual adjustment allows more time to smooth out peaks and valleys in revenues, whereas a monthly adjustment will be influenced by more of the spikes (particularly weather-driven variation), thus the need for a larger bandwidth for the carryover. Like a variable energy rate or fuel adjustment clause that fluctuates monthly, the monthly adjustment introduces more volatility into the rates.

Actual Historical Adjustments

For many ratepayer advocates there is a concern that some of the utility management risk will be transferred to customers as a consequence of a policy that seeks to ensure that the utility will be made whole. However, the utility retains management risk and the requirement to demonstrate that it has acted prudently. Thus the utility still has just as much of an incentive to operate efficiently as it did without revenue regulation. If the utility can lower its costs, it can still increase its profits. Second, by designing rates symmetrically such that under- and over-recoveries are reconciled, it provides customers with an opportunity to obtain credits that under traditional regulation would be retained by the utility. It has often been opined that when there are large gaps in time between utility rate cases, it is because the utility is over-earning and exceeding its revenue requirements. In those instances, customers never get to examine what the utility is collecting, much less receive a refund. Under revenue regulation, with its periodic adjustments and scheduled general rate cases, the revenue requirements are examined and refunds or credits allocated, such that customers have a better knowledge base for understanding the utility's earnings. And annual reconciliation of the utility's actual revenues versus authorized revenues provides consumers with a tool to reign in excess revenue recovery beyond authorized amounts. Third, the adjustments that do occur under revenue regulation are manageable and frequently less than the adjustments customers are used to seeing on their

Figure 1

Total Utility Decoupling Adjustment Rate Impacts[58]



58 Morgan, P. (2012, December). Graceful Systems, LLC. *A decade of decoupling for US energy utilities: rate impacts, designs and observations.* p5.

bills for fuel or variable generation rates, or for the myriad of other surcharges that can be tacked on to a customer's bill, such as an infrastructure (smart grid) surcharge, maintenance upgrade fee, regulatory asset charge, or system benefit charge.

As seen in Figure 1, the range of rate impacts cluster around plus or minus two percent, but can at times exceed plus or minus five percent. The total of surcharges has somewhat exceeded the total of credits.

As can be seen with the utilities studied above, the larger fluctuations are attributable to adjustment mechanisms that are reconciled more frequently, such as monthly, as those are less able to smooth out anomalies as an annual adjustment would do. From a dollar perspective, for the roughly 64 percent of adjustments that fall within the plus or minus two-percent range, the monthly bill impact is approximately $2.30 for average electric customers and $1.40 for average gas customers.[59]

Of the six utilities studied, the fluctuations in adjustment have for the most part stayed within the one- to three-percent range as shown below.

- PG&E from 2005 to 2012 has had annual revenue regulation adjustments ranging from –1.43 percent to 4.15 percent, with an average adjustment of 1.97 percent.
- For IPC, the adjustments are separated between residential and commercial customers. For residential customers, the annual adjustments from 2007 through 2011 ranged from 0.77 percent to 2.58 percent for an average of 1.62 percent. As for the commercial customers, the annual adjustments for that same period were higher, ranging from 1.04 percent to 4.24 percent, with an average adjustment of 2.52 percent.
- BGE has monthly adjustments that ranged from –1.853 percent to 3.013 percent, with an average of 0.57 percent for residential customers from March 2008 through August 2012. For General Service Customers, the monthly adjustment ranged from –2.264 percent to 2.462 percent. The average adjustment was 1.308 percent.
- For WPS, the annual adjustments from 2009 through 2011 ranged from –1.45 percent to 3.78 percent for residential and small commercial, and from –3.14 percent to 8.99 percent for commercial. Note that because of a $14 million per year cap, some of these percentages were carried over. The average annual adjustment for residential and small commercial and for commercial was 1.63 percent and 2.15 percent, respectively, with carry-overs to subsequent years.

59 Id, p 3.

- For Massachusetts Electric and Nantucket Electric, both of which operate under National Grid, the annual revenue regulation adjustment for all for 2011 and 2012 was –0.105 percent and 0.315 percent, for an average revenue regulation adjustment over the two years of 0.105 percent.
- HECO, like National Grid, has one annual revenue regulation mechanism for its customers, which resulted in adjustments in 2011 and 2012 of 0.63 percent and 1.07 percent, respectively, for an average adjustment of 0.85 percent.

As can be gleaned from the above information, the range of average adjustments for small use customers was a low of 0.105 percent for National Grid to a high of 1.97 percent for PG&E. For larger use customers, the range was a low of 0.105 percent for National Grid to a high of 2.52 percent for IPC. This demonstrates that on average for these utilities with well-developed and diversely designed revenue regulation proposals, their adjustments on average stayed at or below approximately 2.5 percent.

One of the metrics for determining if a revenue regulation program is working successfully that was discussed above was the impact on rates of a revenue regulation mechanism. As can be seen by the analysis of the adjustment levels for each of the utilities, they are within a reasonable range.

Complementary Policies

Although a revenue regulation mechanism does not need to be accompanied by other policies, energy efficiency is frequently at the root of the reason revenue regulation was proposed in the first place. The states examined in this paper have various obligations for energy efficiency achievement placed upon their utilities. Only Idaho does not have an Energy Efficiency Resource Standard, but energy efficiency objectives are developed through an integrated resource plan process. Energy efficiency spending at IPC has increased dramatically in recent years.[60]

In recognition of the fact that revenue regulation only removes the disincentive to pursue energy efficiency, several states have instituted some form of incentives to reward the desired outcome. This mechanism can not only incentivize management to aggressively pursue energy efficiency, but also make shareholders supportive in the face of lost investment opportunity.

Rate design can also play an important part in assisting the utility in achieving favorable energy efficiency outcomes. Inclining block rates penalize inefficient use of electricity and shorten payback times from the customer perspective. Because efficiency reduces consumption at the tail block rate,

60 Schultz, T. Energy Efficiency at Idaho Power. Available at: http://www.energy.idaho.gov/energyalliance/d/ida_power.pdf

Table 12

Complementary Policies for Energy Efficiency				
	Energy Efficiency Requirement	**Incentive Structure**	**Default Residential Rate Design**	**Performance Incentives**
Pacific Gas & Electric[61]	*1% annually*	*Risk reward incentive mechanism*	*Inclining block*	*Reliability reporting only*
Idaho Power Company[62]	*IRP*	*No*	*Inclining block*	*None*
Baltimore Gas & Electric	*10% by 2015*	*No*	*TOU, seasonal*	*Under consideration*
Wisconsin Public Service Corporation[63]	*0.75% annually*	*No*	*Flat*	*Reliability reporting only*
National Grid[64]	*2.4% annually*	*5% of program costs*	*Inclining block*	*Service quality reward and penalty*
Hawaiian Electric Company[65]	*Energy efficiency can satisfy portion of RPS*	*Third-party administrator paid for contract performance*	*Inclining block*	*Under consideration*

the value of kWh savings is greater than with flat rates. On the other side of the spectrum, declining block rates, which have a reduced rate in the tail block, do little to encourage conservation. In fact, they operate more like a discounted bulk rate by reducing the average cost of a kWh in a customer's bill for the more kWh used.

Performance incentives or other ways to avoid destructive cost-cutting in the name of creating margins that reduce service or reliability or lessen customer value have been implemented only in Massachusetts of the six

61 Optional rate designs for PG&E include TOU and Peak Time Pricing.

62 IPC also has an optional TOU rate design.

63 Optional rate designs for this utility include TOU, Critical Peak Pricing, and Contract.

64 National Grid also offers optional TOU and flat rate designs.

65 HECO also offers optional TOU and flat rate designs.

utilities illustrated here. Several other states have implemented various schemes in reaction to perceived deficiencies in utility service.[66] Performance incentives are not unique to revenue regulation. Commissions wishing to implement such a scheme can find many models of incentive reward and penalty mechanisms developed for other purposes.

Taken together, a suite of policy and program features can create an atmosphere that is conducive to achievement of energy efficiency goals within the utility and for the customers. By appropriate application of these techniques, regulators, working with utilities and stakeholders, can remove barriers and create an opportunity for energy efficiency to be fully integrated into the utility supply option portfolio.

Table 13

Annual Incremental Energy Efficiency Savings as Percentage of Retail Sales[67]

Highlighted cells are the year that utility started decoupling.

	2004	2005	2006	2007	2008	2009	2010
Pacific Gas & Electric[68]	1.1%	1.6%	1.0%	2.1%	3.5%	2.0%	1.9%
Idaho Power Company	0.1%	0.3%	0.5%	0.6%	1.0%	1.1%	1.3%
Baltimore Gas & Electric	0.0%	0.0%	0.0%	0.0%	0.5%	0.6%	1.7%
Wisconsin Public Service Corporation[69]	0.3%	0.3%	0.3%	0.3%	0.9%	1.0%	0.9%
National Grid	1.1%	0.9%	1.2%	0.9%	0.5%	1.1%	1.36%
Hawaiian Electric Company[70]	0.0%	0.5%	0.5%	0.4%	0.5%	1.1%	1.2%

66 See, e.g., Alexander, B. (1996, April). How to construct a service quality index in performance-based ratemaking. Electricity Policy.

67 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

68 PG&E began revenue regulation in 1974 and it was later suspended and recommenced in 2001.

69 WPS savings are represented by the statewide program savings from the Focus on Energy program. WPS provided additional funds to Focus on Energy, starting in CY10, through their territory-wide program activities.

70 In 2009, Hawaii Energy, a ratepayer-funded statewide energy efficiency provider, began delivering services. Savings reported after 2009 represent savings achieved through the programs of Hawaii Energy.

Energy Efficiency Outcomes

Although revenue regulation itself does not create an incentive for a utility to implement energy efficiency, it does address the issue of lost revenues associated with energy efficiency and DG programs. Revenue regulation should be combined with other mechanisms that require or incentivize the implementation of energy efficiency by the utility or a third party. The level of energy efficiency achieved can be one measure of the success of a revenue regulation mechanism as implemented in a larger program designed to achieve energy efficiency. Table 13 shows the incremental annual energy efficiency savings reported by each utility, with the shaded box indicating the year that the utility's revenue regulation mechanism was implemented. National Grid had achieved a high level of energy efficiency savings in the years before it implemented revenue regulation.

This paper has not evaluated DG outcomes to correlate with revenue regulation, as it is not perceived that states and utilities have made that connection expressly in historical mechanisms. However, it is expected that this connection will be made in future mechanisms, and furthermore it is anticipated that follow on work to this paper will want to study that connection between revenue regulation and DG performance.

Conclusions

An increasing number of states are looking to increase the rate of energy efficiency investments for their long-run cost and risk advantages. The benefits of energy efficiency include not only its ability to reduce system costs across the distribution, transmission, and generation functions, but also the opportunity for customers to reduce their individual energy costs for their own electric bills. Nevertheless, it is counterintuitive to encourage or order a utility to sell less of its product. In order to encourage the proliferation of energy efficiency programs as a solution that can contribute to this nation's energy needs, this tension between the goals of society versus the goals of the utility needs to be addressed. Revenue regulation can be such a solution by removing the link between sales and revenues.

There are many ways to implement revenue regulation and multiple decision points that regulators must consider in designing a revenue regulation mechanism. This paper focused on six utilities, each of which implemented revenue regulation in different ways in accordance with the objectives of that state. Different decision points discussed include:

- Should revenue regulation apply to all functions (generation, transmission, and distribution), which sometimes depends on if the utility is regulated or restructured?
- Should revenue regulation apply to all customer classes?

- Should there be symmetry such that a reconciliation adjustment occurs for both over- and under-recoveries of the revenue requirements?
- Should recovery of indicated surcharges be conditioned on acceptable performance on customer service quality or energy efficiency goals?
- Should there be an attrition adjustment to account for other expenses, or should the revenue regulation adjustment be limited to reconciling existing revenue requirements?
- Should there be an inflation adjustment?
- To calculate the revenue requirements, should the current or accrual method be used?
- Should the adjustments be made in rate cases or through a rider?
- How frequently should adjustments be made: monthly, annually, or some other time period?
- Depending on the period of time between true up and recovery, should there be carrying charges, and if so, how should they be calculated?
- Should there be a requirement authorizing the frequency of rate case?
- Should there be an annual cap on the amount of the adjustment, and if so, should there be an opportunity to carry over any additional amounts and for how many years?
- Should there be an adjustment to the cost of capital to reflect the reduced risk?

Other considerations for regulators, whether or not they implement revenue regulation, but certainly as part of a comprehensive package, are other measures that can be put in place to encourage consumers and utilities alike to actively participate in energy efficiency. For example, an inclining block rate structure by virtue of its incentive to consume less pairs well with an energy efficiency program, helps drive consumers to participate in efficiency programs, and accelerates the payback of an energy efficiency investment. By the same token, an incentive payment to the utility helps provide its management with a good reason to excel and exceed targets for energy efficiency programs.

A key point illustrated by the list of considerations above is that there is not just one static way to design and implement revenue regulation, but rather there are a variety of options for doing so. In this study, a diverse group of utilities were reviewed. The differences among the utilities included geographic diversity, vertically integrated and restructured utilities, different levels of energy efficiency in place, and certainly differences in how the revenue regulation mechanisms were implemented. No two utilities were alike and no two utilities had the same revenue regulation mechanism. The key is that revenue regulation should eliminate the throughput incentive, but the means for accomplishing this goal can vary and be tailored to each jurisdiction and each utility and still be successful.

There are several considerations in the design of a revenue regulation mechanism that can help ensure its successful adoption. To begin, revenue regulation should be granted to utilities only as a precondition to implementing comprehensive energy efficiency and/or DG policies. Unless accompanied by a commitment to engage in providing least-cost resource options that could impact sales, there is not really any good policy reason for its adoption. All of the utilities studied are actively engaging in energy efficiency. Furthermore, as a matter of fairness, the revenue regulation mechanism should be symmetrical so that any revenues above those authorized are refunded back to consumers. As Figure 1 demonstrates, although there are more surcharges to customers, there is nevertheless a healthy amount of credits back to consumers. This is the bargain. Barring imprudence or other unforeseen circumstances, the utility receives its authorized revenue requirements and nothing more or less under a simple revenue regulation mechanism.

Rate design plays an important role in the effectiveness of energy efficiency in concert with revenue regulation. A low customer charge is preferable so that the customer can benefit from real bill reductions tied to reduced volumetric consumption. Reductions in consumption not only reduce bills but also positively impact the payback period for investments in energy efficient appliances. Declining block rates in which the tail block rate is lower than the first tier also do not encourage conservation. Inclining block rates that reward low usage in the first block with a lower rate send the better price signals. None of the six utilities studied had declining block residential rates. They were inclining, flat, and time-varying.

The revenue adjustment mechanism is also a critical decision point in terms of whether a revenue per customer mechanism is adopted that accounts for only the current revenue requirements or whether latitude is given to include an inflation adjustment or other cost increases in the revenue adjustment mechanism. Three of the utilities studied adopted this approach, whereas another two used a hybrid approach. Finally, to reduce volatility, five of the six utilities opted for annual rather than monthly adjustments, thereby creating a level of rate stability that customers in general prefer.

Once the goals for revenue regulation are set by the regulators, the next step is to design programs that will implement that goal. For energy efficiency to be as successful as possible, regulators may want to adopt a complement of other policies to accompany revenue regulation. These can include rate designs that reward reduced use and conservation as well as incentive payments to utilities that reward them for meeting or exceeding targets. Of the six utilities studied, three have adopted some form of incentive. One simple approach that was used in Washington was to link recovery of any surcharges under the revenue regulation mechanism to achievement of energy efficiency targets.[71]

For the utilities examined above that have implemented revenue regulation, the evidence demonstrates that revenue regulation as a strategy and a mechanism to enable energy efficiency has been working well. The fact that each revenue regulation mechanism varies from the next demonstrates that there are many different paths that can be followed in implementing revenue regulation based on the needs of the utility and its stakeholders in a particular region. This study demonstrates that revenue regulation does work and provides examples of how it can be implemented, each one different and unique because of the number of decision points to be considered in designing a revenue regulation mechanism.

71 Avista Utilities. (2009). Washington Utilities and Transportation Commission Docket UE-090134.

Appendix

Historic Rate Adjustments

Table 14

PG&E Revenue Regulation Rate Adjustments 1983 to 1993[72]

Year	Revenue Regulation Adjustment as % of Total Rates
1983	2.3
1984	(3.4)
1985	(4.8)
1986	1.9
1987	2.1
1988	5.0
1989	(4.3)
1990	(5.4)
1991	3.9
1992	3.4
1993	0.0

72 Lesh, P. (2009, June 30). *Rate impacts and key design elements of gas and electric utility decoupling.*

Table 15

PG&E Revenue Regulation Adjustments 2005 to 2012[73]

Year	Delivery Revenue Requirement ($ millions)	Revenue Regulation Adjustment ($ millions)	% of Delivery Revenue
2005	8925	–127.73	–1.43%
2006	9933	224.6	2.26%
2007	10409	217.27	2.09%
2008	10261	40.32	0.39%
2009	11169	103.55	0.93%
2010	11224	465.56	4.15%
2011	10306	383.90	3.73%
2012	11032	403.04	3.65%

73 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 16

IPC Revenue Regulation Adjustments[74]
Idaho Power Company[75]

	Adjustment Rate	Retail Rate	Revenue Regulation Adjustment %
2007			
Residential	–0.0457	5.90	–0.77%
Commercial	–0.0457	4.28	–1.07%
2008			
Residential	0.0529	6.70	0.90%
Commercial	0.0529	5.10	1.04%
2009			
Residential	0.1220	7.70	1.58%
Commercial	0.1535	6.03	2.55%
2010			
Residential	0.1800	7.85	2.29%
Commercial	0.2273	6.13	3.71%
2011			
Residential	0.2028	7.85	2.58%
Commercial	0.2597	6.13	4.24%

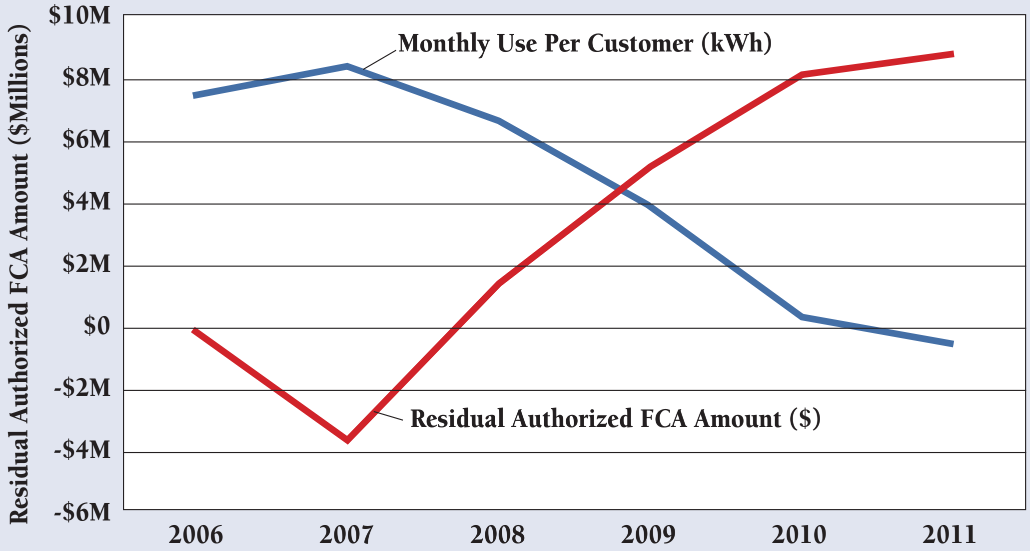
74 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

75 All numbers provided by the utility.

Figure 2

IPC Revenue Regulation Adjustments[76]

Residential FCA Balance and Use per Customer



76 Idaho Power Company. Case No. IPC-E-11-19- fixed cost adjustment permanent mechanism. Available at: http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1119/company/20120928COMPLIANCE%20FILING.PDF

Table 17a

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2008	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
March			
Residential	0.00172	0.1477	1.165%
General Service	0.00230	0.1526	1.507%
April			
Residential	0.00016	0.1477	0.108%
General Service	0.00146	0.1526	0.957%
May			
Residential	0.00066	0.1477	0.447%
General Service	0.00230	0.1526	1.507%
June			
Residential	–0.00066	0.1477	–0.447%
General Service	0.00230	0.1526	1.507%
July			
Residential	0.00158	0.1477	1.070%
General Service	0.00230	0.1526	1.507%
August			
Residential	–0.00040	0.1477	–0.271%
General Service	0.00214	0.1526	1.402%
September			
Residential	0.00237	0.1477	1.605%
General Service	0.00230	0.1526	1.507%
October			
Residential	0.00237	0.1477	1.605%
General Service	0.00143	0.1526	0.937%
November			
Residential	0.00237	0.1477	1.605%
General Service	0.00140	0.1526	0.917%
December			
Residential	0.00445	0.1477	3.013%
General Service	0.00230	0.1526	1.507%

77 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 17b

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2009	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00035	0.1579	0.222%
General Service	–0.00073	0.1346	–0.542%
February			
Residential	0.00025	0.1579	0.158%
General Service	0.00230	0.1346	1.709%
March			
Residential	–0.00237	0.1579	–1.501%
General Service	0.00230	0.1346	1.709%
April			
Residential	–0.00237	0.1579	–1.501%
General Service	0.00230	0.1346	1.709%
May			
Residential	0.00234	0.1579	1.482%
General Service	0.00132	0.1346	0.981%
June			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
July			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
August			
Residential	0.00237	0.1579	1.501%
General Service	0.00190	0.1346	1.412%
September			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
October			
Residential	0.00237	0.1579	1.501%
General Service	0.00124	0.1346	0.921%
November			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
December			
Residential	0.00156	0.1579	0.988%
General Service	0.00204	0.1346	1.516%

Table 17c

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2010	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00203	0.1465	1.386%
General Service	0.00230	0.1261	1.824%
February			
Residential	–0.00142	0.1465	–0.969%
General Service	0.00230	0.1261	1.824%
March			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00230	0.1261	1.824%
April			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00230	0.1261	1.824%
May			
Residential	0.00192	0.1465	1.311%
General Service	0.00230	0.1261	1.824%
June			
Residential	0.00191	0.1465	1.304%
General Service	0.00230	0.1261	1.824%
July			
Residential	0.00095	0.1465	0.648%
General Service	0.00230	0.1261	1.824%
August			
Residential	–0.00176	0.1465	–1.201%
General Service	0.00224	0.1261	1.776%
September			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00116	0.1261	0.920%
October			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00081	0.1261	0.642%
November			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00098	0.1261	0.777%
December			
Residential	–0.00079	0.1465	–0.539%
General Service	0.00229	0.1261	1.816%

Table 17d

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2011	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	–0.00130	0.1365	–0.952%
General Service	0.00230	0.1156	1.990%
February			
Residential	–0.00253	0.1365	–1.853%
General Service	–0.00020	0.1156	–0.173%
March			
Residential	–0.00018	0.1365	–0.132%
General Service	–0.00063	0.1156	–0.545%
April			
Residential	0.00110	0.1365	0.806%
General Service	–0.00262	0.1156	–2.266%
May			
Residential	0.00010	0.1365	0.073%
General Service	–0.00160	0.1156	–1.384%
June			
Residential	0.00226	0.1365	1.656%
General Service	0.00042	0.1156	0.363%
July			
Residential	0.00253	0.1365	1.853%
General Service	0.00209	0.1156	1.808%
August			
Residential	–0.00007	0.1365	–0.051%
General Service	–0.00157	0.1156	–1.358%
September			
Residential	–0.00253	0.1365	–1.853%
General Service	–0.00177	0.1156	–1.531%
October			
Residential	0.00228	0.1365	1.670%
General Service	0.00262	0.1156	2.266%
November			
Residential	–0.00059	0.1365	–0.432%
General Service	0.00262	0.1156	2.266%
December			
Residential	0.00071	0.1365	0.520%
General Service	0.00262	0.1156	2.266%

Table 17e

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2012	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
February			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
March			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
April			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
May			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
June			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
July			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
August			
Residential	0.00253	0.1291	1.960%
General Service	0.00160	0.1064	1.504%

Table 18

Wisconsin Public Service Corporation
Revenue Regulation Adjustments 2009 to 2011[78]

	Derived Adjustment $/kWh	Derived Adjustment Capped $/kWh	Retail Rate $/kWh	Revenue Regulation % Actual	Revenue Regulation % Capped
2009					
Residential/ Small Commercial	0.0048705	0.00168154	0.1290	3.78%	1.30%
Commercial	0.0084951	0.00293293	0.0945	8.99%	3.10%
2010					
Residential/ Small Commercial	0.0033043	0.00166936	0.1291	2.56%	1.29%
Commercial	0.0056630	0.00286103	0.9460	0.60%	0.30%
2011					
Residential/ Small Commercial	(0.0018666)	$ (0.00163719)	0.1288	–1.45%	–1.27%
Commercial	(0.0032565)	$ (0.00285629)	0.1037	–3.14%	–2.75%

78 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 19

National Grid
Revenue Regulation Adjustments, 2011-2012[79]
Massachusetts Electric and Nantucket Electric

	Revenue Regulation Adjustment ¢kWh	Retail Rate ¢kWh	Revenue Regulation Adjustment %
2011 All	–0.015	14.29	–0.105%
2012 All	0.044	13.96	0.315%

Table 20

Hawaiian Electric Company

	Revenue Regulation Adjustment ¢kWh	Retail Rate	Revenue Regulation
2011	0.1995	31.49	0.63%
2012	0.3894	36.41	1.07%

"The 2011 adjustment took effect June 1 but was reduced to $0 on July 26, 2011 when the Commission granted HECO an interim rate increase of $53.2 million in a 2011 test year general rate case. The 2012 Adjustment runs from June 1, 2012 through May 31, 2013. About 25% of the total relates to the portion of the decoupling mechanism that updates O&M and rate base." (Morgan, 2013)

79 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Additional Resources

Decoupling Design: Customizing Revenue Regulation to Your State's Priorities

http://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities

The history of U.S. states' adoption of revenue regulation, or decoupling—the separation of sales and revenues to mitigate the impact on utilities' bottom line of energy efficiency and distributed energy resources—demonstrates that no two decoupling mechanisms are alike. Over the process of their design, these mechanisms contain a number of decision points that address policy and stakeholder priorities. From an overall perspective of the good of the state, or from the distinct perspective of individual stakeholders, these decisions will enhance the decoupling mechanism or make it less attractive. This paper, the third in a trilogy of RAP papers on decoupling, examines these decision points in detail. It considers the applicability of revenue regulation by utility function, customer class, and included and excluded costs; the frequency and timing of rate cases; the design of a revenue adjustment mechanism; and issues such as rate design and bill simplification. It then lays out representative pathways for states considering a decoupling mechanism.

Pricing Do's and Don'ts: Designing Retail Rates as if Efficiency Counts

http://www.raponline.org/knowledge-center/pricing-dos-and-donts-designing-retail-rates-as-if-efficiency-counts

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements can guide consumers to participate in energy efficiency programs and reduce peak demand, yet relatively few utilities and commissions have implemented many of these elements. This RAP paper identifies some best practices. Because pricing issues tie closely to utility growth incentives, we also address revenue decoupling.

A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs and Observations

http://www.raponline.org/knowledge-center/a-decade-of-decoupling-for-us-energy-utilities-rate-impacts-designs-and-observations

This report, written by Pamela Morgan of Graceful Systems LLC, builds on a 2009 report. Now covering 25 states, including 49 LDCs and 24 electric utilities, this report summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. In total, this report estimates the retail rate impacts of 1,244 decoupling mechanism adjustments since 2005.

The Role of Decoupling Where Energy Efficiency is Required by Law

http://www.raponline.org/knowledge-center/the-role-of-decoupling-where-energy-efficiency-is-required-by-law

This Issuesletter gives an overview of energy efficiency resource standards, the need to decouple utility profits from utility sales, and explains why decoupling is needed even where a third party administers energy efficiency programs.

Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission

http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, decoupling, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). This report is the output of that collaboration.

Designing Distributed Generation Tariffs Well

http://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

http://www.raponline.org/knowledge-center/rate-design-where-advanced-metering-infrastructure-has-not-been-fully-deployed

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

Time-Varying and Dynamic Rate Design

http://www.raponline.org/knowledge-center/time-varying-and-dynamic-rate-design

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

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Attachment B

Lifting the Cap: Estimating the Economic Impacts of Energy Efficiency Investments in Pennsylvania

Annie Gilleo and James Barrett

April 2019

An ACEEE White Paper

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Annie Gilleo manages ACEEE's state-based technical assistance activities and conducts research on energy efficiency resource standards, the utility business model, and other state-level policies. She was also the lead author of the 2013–2015 editions of the State Energy Efficiency Scorecard. Prior to joining ACEEE, Annie held an Environmental Defense Fund Climate Corps Fellowship at the Smithsonian Institution and interned at the White House Council on Environmental Quality. Annie earned a master of public policy from Georgetown University and a bachelor of arts in environmental sciences from the University of California, Berkeley.

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Abstract

This paper analyzes the job-creation impacts of increased energy efficiency investments from electric distribution utilities in the Commonwealth of Pennsylvania. Under current Pennsylvania law, efficiency investments are artificially capped, limiting energy savings and associated economic benefits. Using input–output modeling, we evaluate the economic impacts of a scenario unconstrained by an investment cap, where electricity savings rise to 1.2% over the period 2021–2025. We find that unconstrained investments could create more than 30,000 jobs, a 50% increase compared to a scenario where a cap constrains them.

Background

In 2008, the Pennsylvania legislature passed Act 129, establishing the framework for the Commonwealth's electric savings targets. The act called on the Public Utility Commission (PUC) to establish an energy efficiency and conservation (EE&C) program beginning in 2009. This program requires each electric distribution company (EDC) with at least 100,000 customers to adopt a plan to reduce energy consumption within its service territory. These EDCs include Duquesne Light Co., Metropolitan Edison Co. (Met-Ed), Pennsylvania Electric Co. (Penelec), Pennsylvania Power Co. (Penn Power), West Penn Power Co., PECO Energy Co., and PPL Electric Utilities. Together, they serve more than 5.5 million customers across Pennsylvania (EIA 2018).

Act 129 included specific minimum consumption reductions for Phase I, requiring each EDC to achieve energy savings of at least 1% by May 31, 2011, and 3% by May 31, 2013. The legislation included several other important components, including instructions for reporting, penalties for failure to meet energy savings targets, and a requirement that EE&C plans not exceed 2% of EDC total 2006 revenue (Pennsylvania General Assembly 2008).

Energy savings targets for Phase II were set by the Pennsylvania PUC. The targets covered the three-year period from June 2013 to May 2016, with compliance assessed at the end of the phase. Targets were utility-specific and ranged from 1.6% savings over three years for West Penn Power to 2.9% for PECO. The average annualized target across all seven obligated EDCs was about 0.72% (Pennsylvania PUC 2017). Phase III targets were also set by the PUC and covered a longer period (June 2016–May 2021). These ranged from 2.6% over five years for West Penn Power to 5% for PECO, equivalent to about 0.5% to 1% annualized electricity savings (Pennsylvania PUC 2015b).[1] Averaged statewide, these targets are equivalent to about 0.8% of sales (ACEEE 2017).

For Phases II and III, the PUC set targets based largely on the results of potential studies conducted by the Statewide Evaluator (SWE).[2] These studies include three estimates of potential: maximum achievable potential, with incentives equivalent to 100% of measure costs and accordingly higher participation rates; base achievable potential, with incentives based on historic levels; and program potential, which constrains EE&C program rollout to levels lower than base achievable due to the cost cap. As the PUC noted in its Final Implementation Order for Phase III, "Without a budget cap, incremental annual savings could achieve roughly 1.2% to 2.0% of 2010 load in the base achievable and maximum achievable scenarios, respectively" (Pennsylvania PUC 2015b). Table 1 shows cumulative results of the SWE potential study for Phase III as well as the final targets adopted by the PUC.

[1] EDCs are not required to achieve savings evenly over each year of the phase. However the Phase III Implementation Order does ask EDCs to achieve at least 15% of the required electricity savings in each year of the phase.

[2] Final targets deviated somewhat from the results of the SWE studies based on stakeholder input as part of Docket Nos. M-2012-2289411 and M-2008-2069887.

Table 1. Sum of incremental statewide efficiency potential for Phase III EE&C programs

	Maximum achievable potential	Base achievable potential	Program potential	Implemented target
Statewide average	9.8%	6%	4.5%	3.5%

Savings represent the sum of incremental savings to be achieved over the five-year phase. Note that the implemented target is slightly below the calculated program potential to accommodate greater spending on low-income programs. *Source:* Pennsylvania PUC 2015b.

Over the first seven years of program implementation, EDCs have delivered significant energy savings to residents and businesses across Pennsylvania, consistently meeting goals (Pennsylvania PUC 2017). Act 129 delivered $6.4 billion in benefits to customers by the end of Phase II (KEEA 2018), and benefits will continue to accrue throughout Phase III. However electricity savings remain below the base achievable potential in the state and below savings achieved in neighboring states such as Maryland, New York, and Ohio, which are driven by stronger goals (Berg et al. 2018). Table 2 shows electricity savings goals for neighboring mid-Atlantic states.

Table 2. Electricity savings goals for neighboring states

State	Average annual savings target
Maryland	2.0%
New York	2.0%
New Jersey*	1.5%
Ohio	1.0%
Pennsylvania	0.80%

* New Jersey achieved savings equivalent to Pennsylvania in 2017 but set stronger targets in 2018.

The next phase of Act 129 will begin in 2021. In this paper, we estimate the economic impacts of a ramp-up to 1.2% incremental electricity savings over five years. We analyze 1.2% because it is an achievable level of energy savings, about equivalent to the base achievable scenario identified by the SWE's Phase III potential study.[3] It is also consistent with the increase in energy savings evaluated in a 2018 study of economic impacts by Takahashi, Malone, and Hall of Synapse Energy Economics, Inc.

Results

If energy savings rise gradually to 1.2% over Phase IV due to its programs and targets, we estimate that energy efficiency measures installed between 2021 and 2025 would create enough economic activity (during installation and over the life of the measures) to support

[3] Statewide base achievable incremental savings as calculated by the SWE ranged from 1.1% to 1.3% over the period 2016–2020.

more than 30,000 jobs in Pennsylvania.[4] This increase in employment would be driven by a combination of the efficiency investments and the customer bill savings they generate. Pennsylvania families and businesses would save over 90,000 GWh and about $6.4 billion net over the life of the installed measures.

In the scenario analyzed in this paper, energy savings increase by about 50% over current cost-constrained levels. If EDCs continue to implement programs at constrained base-case levels, we would still expect to see jobs created across Pennsylvania. However the impacts would be smaller, about 20,000 jobs and $4.3 billion in net savings for energy consumers across the state. Figure 1 shows job impacts by year for both the base (cost-constrained) and the alternate (unconstrained) cases.

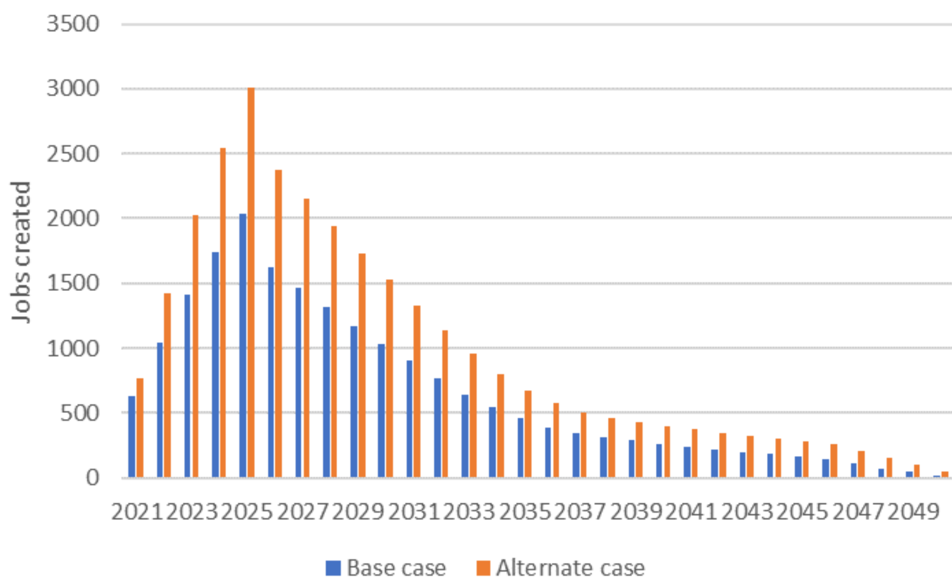

Figure 1. Jobs created by year for a five-year implementation phase beginning in 2021. Although the efficiency programs examined in this analysis run only through 2025, job impacts linger, with new jobs being created through 2050. If efficiency programs continue to be implemented past 2025, jobs numbers would continue to grow.

The largest share of the job creation impacts stem from two separate influences. The first is the growth in demand for industries that implement energy efficiency measures. These include various construction and related industries as well as their supply chains. With an investment of over $2.5 billion over a five-year period, employment in these industries will increase by about 20,000 jobs. However these jobs tend to be relatively short-lived, lasting only as long as they are required to implement the programs.

The second would occur in the service sector, including retail industries. Consumers and businesses spend a significant share of their disposable income on services of various types.

[4] The term *job* in this context means one year of full-time-equivalent employment. Our analysis presents results in terms of net jobs, accounting for both job creation and job loss in different sectors of the economy.

These services would see a large increase in demand and job creation. These jobs will be longer term, as consumers spend their energy bill savings year after year, but may be harder to identify as they will be spread over a larger portion of the economy and a longer period.

Methodology

In this paper, a *job* is defined as one year of full-time-equivalent employment. One job could be one person employed full time for one year, or two people employed half time for a year, or one person employed half time for two years, and so on.

We report results in terms of jobs created. A created job can be either a new job generated or a job not lost. The dynamic energy efficiency policy evaluation routine (DEEPER) model (described in Appendix A), like most similar models, calculates the number of full-time-job equivalents that would be supported by the activities under consideration, but it cannot tell whether these are newly created jobs or ones that would otherwise disappear.

We report our employment results in terms of net jobs created. This accounts for both jobs created or saved and jobs that might be lost due to changes in spending patterns resulting from the policy in question. In particular, we account for any jobs lost in electricity generation and related sectors.

We used our DEEPER modeling framework to estimate the economic impacts of lifting the cost cap to remove artificial spending constraints on the implementation of Phase IV of Act 129. We based our estimates of cost-effective savings on a scenario in which targets are not constrained by an arbitrary cost cap. We include in our analysis the full investments EDCs would need to undertake to achieve these savings along with any changes in revenue resulting from implementation of EE&C programs.

SAVINGS

We base potential Phase IV savings on a 2018 study by Takahashi, Malone, and Hall of Synapse Energy Economics, Inc. assessing the impacts of expanding EE&C programs beyond the current budget caps. Synapse estimated that savings would increase by 0.2% of sales per year throughout Phase IV, with EDCs reaching 1.2% savings on average by 2025. The study found that removing cost caps and allowing for a gradual program ramp-up would result in 50% more investment in energy efficiency and provide 50% more savings and net benefits. Figure 2 illustrates the difference in savings.

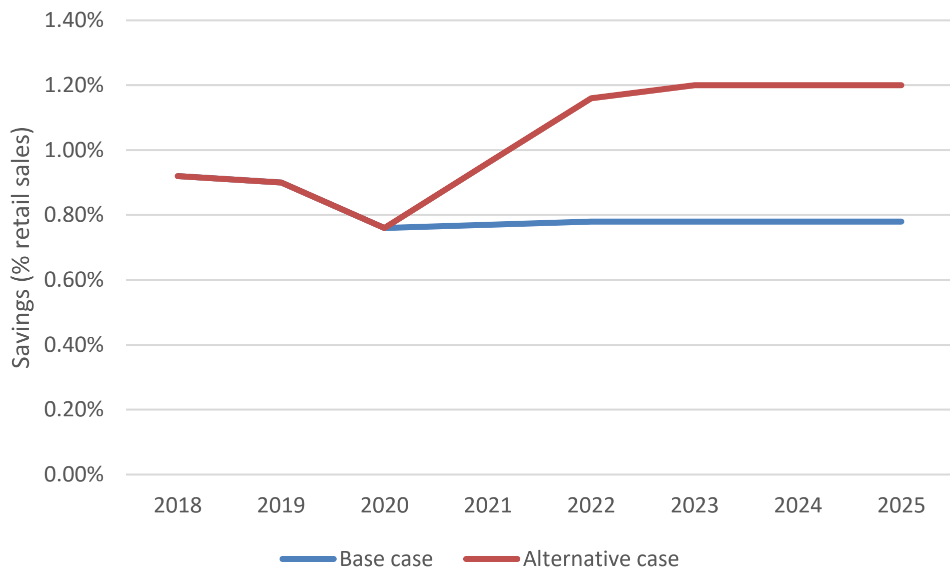

Figure 2. Estimated energy savings for base case (with cost cap constraint) versus alternative case. *Source:* Takahashi, Malone, and Hall 2018.

Consistent with the Synapse study, the savings estimates we present are relatively conservative. In the most recent statewide potential study, the SWE found base achievable incremental savings to be 1.2% in 2025. This represents savings based on historical incentive levels and adoption rates and does not account for improvements in program design or higher levels of incentives. Maximum achievable savings were 50% higher: 1.8% (Pennsylvania PUC 2015).

We also assume that Phase IV of Act 129 implementation occurs over a five-year period, from 2021 to 2025. This is consistent with the length of Phase III implementation. In its Phase III Implementation Order, the commission noted that the five-year phase would "aid in the implementation of more comprehensive programs" and that a "five year program provides additional benefits, such as savings in costs, time and resources related to litigating and administering the EE&C plans" (Pennsylvania PUC 2015b, 14). The commission cited additional benefits of the five-year phase, including "more consistency and continuity, further enhancing the customer experience and increasing the potential for customer engagement in the program" (Pennsylvania PUC 2015b, 14–15). While Act 129 is likely to continue through future phases, we limit our analysis to the likely length of Phase IV. If savings targets continue into the future, or energy savings rise to levels higher than those included in our analysis, the EE&C programs would likely deliver additional net jobs to the Commonwealth.

Figure 3 shows total annual savings from 2021–2025 measures.

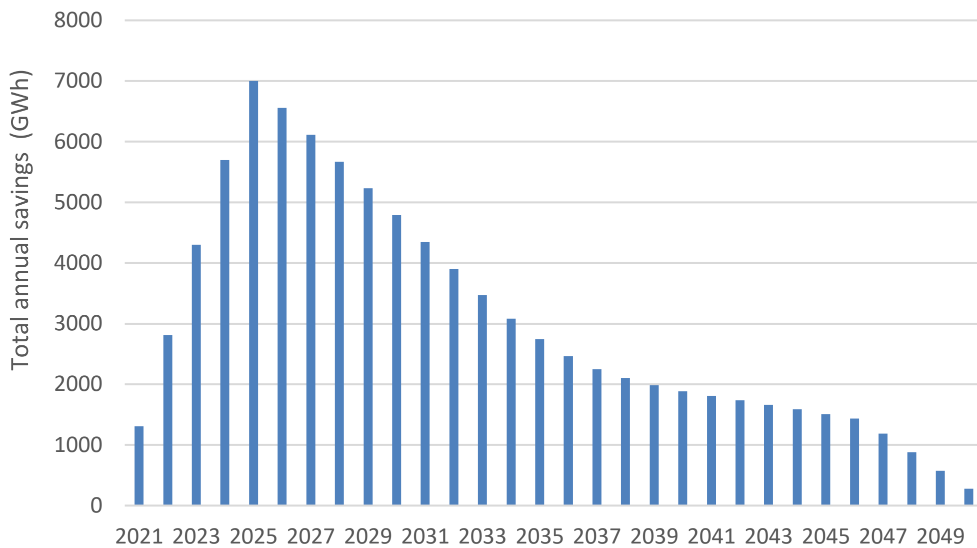

Figure 3. Total annual savings from measures installed 2021–2025. Savings persist long after the program phase examined in this report. If program implementation were to continue past 2025, savings would continue to grow.

Figure 3 shows the savings from Phase IV programs last well beyond 2025. Efficiency measures typically continue to save energy after they are put in place, and those installed during Phase IV continue returning some savings through 2050. Figure 3 shows savings beginning to decline in 2026, reflecting our assumption that savings from efficiency measures decrease over time.[5] We model this decline as a straight-line reduction in performance beginning in the year after the measures are put in place and continuing until they reach their maximum expected life. We expect the average useful life of residential efficiency measures to be just over 6 years and that of commercial and industrial (C&I) measures to be about 13 years.[6] That means that while half of the commercial measures may need to be replaced in 13 years, we anticipate that half will last longer than that, with a small share of them functioning for 26 years.

COSTS

We modeled investments required to ramp up to 1.2% electricity savings using budgets laid out by Takahashi, Malone, and Hall (2018). In that study, program costs of saved energy were based on EDC reported costs for 2016 and Phase III projected costs for 2017–2020. The study used a statewide average cost of saved energy and adjusted projected costs by comparing planned versus actual costs in 2016. As in Takahashi, Malone, and Hall (2018), we used EDC's Phase III filings to split program costs and savings between residential and C&I sectors.

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[5] Our analysis is limited to a five-year period. If EE&C programs are approved past 2025, total annual savings would likely continue to grow.

[6] These measure lives are consistent with Takahashi, Malone, and Hall (2018) and based on data reported by EDCs for EE&C Program Year 8.

We estimate cost savings by multiplying energy savings by average retail electricity prices in Pennsylvania in 2017, about $0.14 per kWh for residential customers, $0.09 for commercial customers, and $0.067 for industrial customers. We also use electric-sector growth rates from the US Energy Information Administration (EIA), about 0.6% annually for residential and commercial sectors and 1% for the industrial sector (EIA 2019). Pennsylvania EDCs report program savings for C&I customers (separating large and small) without distinguishing between the commercial and industrial sectors. For the purposes of our analysis, we have assumed that efficiency investments across these two categories are split evenly between commercial and industrial customers and have allocated the economic inputs and outputs accordingly.

Finally, because Pennsylvania is a net exporter of electricity, we assume that any reductions in electricity consumption come at the expense of reduced generation in the state as opposed to reductions in electricity imports from other states.

Conclusion

Allowing energy efficiency programs to grow beyond current levels in Pennsylvania could be a major job creator for the Commonwealth. Energy efficiency programs have hyperlocal employment impacts, generating not only demand for contractors and the construction sector, but also more-diffuse job-creation impacts due to the energy savings these programs generate. Unleashing these economic benefits will require ramping up efficiency across Pennsylvania, engaging businesses and residents alike to generate energy savings and create jobs.

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Appendix A. ACEEE's DEEPER Model

We have used ACEEE's DEEPER modeling framework to conduct this assessment. DEEPER employs principles of input–output (I/O) modeling to evaluate the economic impacts of various policy alternatives. Simply put, the model tracks changes in demand for goods and services across the Pennsylvania economy and determines how much output from each economic sector is required to meet that demand. It then asks how much labor is required to produce that output and how much state gross domestic product (GDP) (or value added) is associated with that change in demand.

The core of the DEEPER model is the A matrix, or direct requirements matrix. This relates industries to one another, detailing how much input from one industry is required to make a dollar's worth of output from another industry. Combining this information with a final demand vector, which represents changes in demand for goods and services for final consumption, returns the amount of output required from each industry to support that level of final demand. For any given increase in final demand of goods and services, determining how much additional output each industry would have to create to meet this increase is conceptually straightforward.

A second critical component of DEEPER is a set of multipliers that convert the resulting increases in output into the amount of employment needed to bring about those increases, how much income that would generate for workers, and how much GDP that would create. DEEPER uses data from the IMPLAN Group for its national and state-level A matrices and multipliers.

We calculate changes in final demand using data on expenditures on energy efficiency, the lifetime energy savings they generate, and the associated avoided energy costs as described in the preceding. We consider the cost of the efficiency investments as well as the lost revenues to utilities that result from reduced energy consumption. We also account for interstate and international trade by using regional purchase coefficients that indicate how much of each type of good and service consumed in Pennsylvania is also produced there. The model allocates changes in final demand among in-state and out-of-state producers accordingly, so that only changes in Pennsylvania-based producers contribute to state employment and value added.

We aggregate all of these state-level impacts to calculate the net change in Pennsylvania final demand across 14 economic sectors. The DEEPER model translates these net changes into changes in output and calculates the changes in employment and value added associated with them. The model includes employment and value added associated with the changes in demand, changes in production along the supply chain required to meet that demand, and increased economic activity generated by workers spending their increased income.

Attachment C

Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms

Annie Gilleo, Marty Kushler, Maggie Molina, and Dan York

June 2015

Report U1503

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Annie Gilleo joined ACEEE in 2013. She is the lead author for the *State Energy Efficiency Scorecard*, and she conducts research on energy efficiency resource standards, utility regulatory structures, and other state-level efficiency initiatives.

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Dan York has more than 20 years of experience in researching, analyzing, and implementing energy efficiency programs and policies. He is widely recognized for his work tracking and analyzing trends and emerging issues in utility-sector energy efficiency programs. His entire educational and professional experience has focused on energy efficiency and conservation as the foundations for a sustainable economy. He joined ACEEE in 2001.

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Executive Summary

Energy efficiency is one of the lowest-cost, cleanest, most reliable options available to utilities to meet customer demand. Yet a number of historical regulatory practices have combined to impede the use of energy efficiency as a resource, and the ability to address some of those practices has played a crucial role in the expansion of utility efforts regarding customer energy efficiency programs.

York et al. (2013) list the three main disincentives to utility investment in energy efficiency:

1. The costs of efficiency programs constitute financial losses to utilities unless they are able to recover those costs through rates or fees.
2. Investments in capital assets like power plants provide a return on investment under the traditional utility business model. Expenditures on energy efficiency programs avoid the need for these capital investments but do not provide a return.
3. The traditional utility business model is based on a throughput incentive, whereby utilities earn more profits by selling more electricity. Investments in energy efficiency drive down energy use and therefore utility revenues. However efficiency does not reduce the short-term, fixed costs of providing service.

State regulators have sought to address these three major disincentives through particular adjustments to utility regulatory frameworks. This paper examines one mechanism meant to deal with a utility's disincentives to invest in energy efficiency: a *lost revenue adjustment mechanism (LRAM)* or *lost contribution to fixed costs (LCFC)*. An LRAM is a rate adjustment mechanism that allows a utility to recover revenues that are reduced specifically as a result of energy efficiency programs.

States often use LRAM as an alternative to decoupling. Decoupling is a mechanism that makes small adjustments to rates and breaks the link between the amount of electricity or natural gas utilities sell and the revenue they are allowed to recover. Rates vary so that revenues—regardless of sales—are fully recovered. With decoupling in place, a utility is indifferent to changes in sales due to any factor, including efficiency programs or weather patterns.

LRAM differs from decoupling in two key ways. First, LRAM requires a utility to estimate energy savings over a given time period. Decoupling requires no such estimation. Second, LRAM is typically not symmetrical. That is, while a utility can recover lost revenues from efficiency programs, regulators do not make additional adjustments if the utility sells more energy than predicted in the test year. Decoupling is symmetrical and can result in both customer refunds and surcharges.

In recent years, many states have adopted the LRAM approach to address utilities' throughput incentive. In 2011, an ACEEE paper detailed the experience of several states with LRAM in place. Since that time, more states have adopted this type of regulatory mechanism, and many states have had several years of experience with it. Currently, 17 states have LRAMs in place for at least one major utility. At the same time, however, several states that had LRAM policies in the past have moved toward decoupling.

ANALYSIS OF CURRENT LRAM POLICIES

We asked states to submit information on their LRAM policies, lost revenue dollars eligible for recovery by utilities in the two most recent program years, and program costs and annual savings from energy efficiency programs for each of those years. Fifteen states responded with quantitative data.

The amount utilities were eligible to recover for electricity savings ranged from $0.02 per kWh to $0.13 per kWh, with a median of $0.05 per kWh. For natural gas, eligible recovery amounts ranged from $0.09 per therm up to $0.33 per therm, with a median of $0.19 per therm. This range speaks to differences in base rate designs and lost revenue calculation inputs for the states and utilities profiled, as well as the effect of pancaked savings, i.e., the compounding of savings from measures installed in multiple years.

LRAM dollars also varied in comparison with program costs for the electric utilities we surveyed. At the low end of the range, dollars collected for lost revenue were equivalent to only about 1% of electricity efficiency program costs in a given year. However for one utility surveyed, lost revenues recovered were equivalent to more than 70% of program costs. In this case it is likely that several years of recovery were rolled into a single rate case.

LESSONS LEARNED

An LRAM can bring parties to the table. Decoupling, or the separation of energy sales from a utility's profit calculation, is the simplest way to ensure that a utility meets its revenue requirement even if other factors dampen sales. But in many states, key parties view decoupling unfavorably. While LRAM is not a perfect substitute for decoupling, it can bring parties to the table in circumstances where decoupling is not feasible. LRAM can serve as a first-step policy solution on the way to decoupling.

Good evaluation, measurement, and validation (EM&V) is important. To prevent overcharging customers or undervaluing a utility's lost revenues, utilities and regulators need to get the savings right. Evaluation of savings is controversial in many of the states in which we conducted interviews. Though evaluation procedures were already in place for efficiency programs in many states, when lost revenues were at stake the scrutiny became far greater. It is important that all parties understand and agree to evaluation procedures. The evaluation process should be rigorous and transparent, with appropriate checks along the way.

Timing matters. Timing is critical to precise, efficient implementation of an LRAM. Since energy efficiency program decisions and rate-making decisions are necessarily intertwined in states with an LRAM in place, aligning these two functions to occur at the same time can help streamline processes. Intervals between rate cases also matter. Frequent rate cases avoid the issues associated with pancaked savings.

An LRAM alone will not fully incentivize efficiency nor remove the throughput incentive. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales associated with efficiency programs, it will do little to *encourage* investment in energy efficiency unless combined with other policy levers. In fact, our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Nor does LRAM reduce a utility's motivation to increase sales (although some states do have safety nets in place). To fully remove the throughput incentive, decoupling should be considered. Regulators can prioritize energy efficiency by setting energy savings targets through an energy efficiency resource standard (EERS) and implementing performance incentives tied to specific energy saving levels. They can also help encourage efficiency investments by requiring utilities to evaluate energy efficiency in the same manner as other supply-side resources during resource planning.

CONCLUSION

Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best third leg of this stool. However it is also clear that decoupling is not always an option for states for a variety of reasons. In such scenarios, LRAM can be a temporary solution, offering a mechanism to address the concern over lost revenues and, possibly, help make parties more comfortable with the idea of full decoupling in the future.

Introduction

Utilities and regulators are making major changes to the utility industry across the country. As utilities try to become more service oriented, they are paying more attention to alternative business models, particularly those that value investments in energy savings. Energy efficiency is one of the lowest-cost, cleanest, most reliable options available to utilities to meet customer demand. Saving energy offers a wealth of opportunities for both utilities and the public. Investments in energy efficiency can reduce energy costs for families and businesses, create jobs, and improve the environment. Efficiency programs can help consumers control how and when they use energy, and they can help utilities build friendlier, service-oriented relationships with their customers.

Utility investments in energy efficiency have greatly increased since the mid-2000s. In 2004, utilities nationwide invested slightly less than $1.5 billion in energy efficiency programs. By 2014, investments had jumped to $7.7 billion (Gilleo et al. 2014). A variety of factors spurred this investment. Utilities were searching for cheaper ways to meet rising demand, states were looking for cleaner energy options for businesses and residents, and consumers wanted to reduce their utility bills.

A number of historical regulatory practices have combined to impede the use of energy efficiency as a resource. In order to address these barriers, states have adopted regulatory mechanisms to incentivize utilities to include energy efficiency in their portfolios. These adjustments to the traditional business model have played a crucial role in the expansion of utility energy efficiency programs.

TRADITIONAL REGULATION AND ITS PITFALLS

It is an unfortunate fact that the traditional utility business model conflicts with the objective of increasing customer energy efficiency. Traditional utility regulation structures developed with a focus on raising large amounts of capital to build the giant power plants and massive transmission and distribution network that we have in place today. Despite shifts in the energy industry in recent years, including far more emphasis on distributed resources and energy efficiency, the traditional utility regulatory structure is still generally in place, with little variation from state to state (York and Kushler 2011).

Utilities and regulators have historically set rates for electricity or gas sales through adjudication processes called rate cases. First they set revenue requirements by aggregating all of the utility's costs of providing service. They then calculate the rates necessary to recover these costs plus some reasonable return to the utility. Traditional regulation relies on two basic formulas (RAP 2011):

> *Revenue requirement* = *Expenses* + *Return* + *Taxes*
> *Rate* = *Revenue requirement/Units sold*

This traditional business model gives a utility the incentive to sell more electricity or natural gas. If it can sell more units of energy than were used to calculate its rate, the utility can earn more than its base revenue requirement.

This underlies one of the three disincentives to utility investment in energy efficiency under the traditional regulatory approach as described by York et al. (2013):

1. The costs of efficiency programs constitute financial losses to utilities unless they are able to recover those costs through rates or fees.
2. Investments in capital assets like power plants provide a return on investment under the traditional utility business model. Expenditures on energy efficiency programs avoid the need for these capital investments but do not provide a return.
3. The traditional utility business model is based on a throughput incentive, whereby utilities earn more profits by selling more electricity. Investments in energy efficiency drive down energy use and therefore utility revenues. However efficiency does not reduce the short-term fixed costs of providing service.

Despite these disincentives, state regulators and other stakeholders across the country see value in efficiency investments, and they have been working with utilities to adjust the traditional business model in ways that encourage them. Utilities are key partners in delivering efficiency, and states need to get them on board to maximize energy savings. The traditional business model is not going to work for the utilities of the future.

Common Strategies for Balancing Interests

State regulators have sought to address the disincentives to energy efficiency investments through adjustments to utility regulatory frameworks.

Program cost recovery is a widespread regulatory practice that allows utilities to recover the costs of energy efficiency programs through rates. Efficiency program costs are typically treated as pass-through expenses which the utility may recover by adding a surcharge to the rates it charges customers. Alternatively the costs may be capitalized and the utility may raise rates to earn a return on the money it invested in efficiency

Performance incentives offer utilities financial rewards for saving energy through efficiency programs. Incentives make these programs into a source of earnings rather than just pass-through expenses. This puts energy efficiency investments on a comparable footing with investments in new power plants or transmission and distribution, which are allowed to earn a rate of return. Performance incentives help make up for the earnings opportunities utilities forego when, due to energy efficiency, they do not need to invest as much in their supply infrastructure. The companion report to this one (Nowak et al. 2015) discusses incentive designs, which vary widely.

Decoupling is the most straightforward solution to the throughput incentive. It breaks the link between the amount of electricity or natural gas the utility sells and the revenue it is allowed to take in (RAP 2011). Under decoupling, a utility is guaranteed to earn a specific amount, no more, no less, regardless of how much energy it sells. Its revenue is based on a regulatory formula rather than on the amount of energy its customers use. Revenue requirements are established in rate cases, and then decoupling true-ups occur outside of these cases. True-ups make small adjustments to rates based on actual sales. If the utility sells more energy than projected, it is required to refund customers. If it sells less, it is allowed to raise rates to reach its revenue requirement. Under decoupling, a utility is indifferent to changes in sales due to any factor, whether weather, efficiency programs, or anything else. Decoupling is in place in about half of the states for electric or natural gas utilities or both (Morgan 2013).[1]

As an alternative to decoupling, many states have opted to address the throughput incentive with a different regulatory tool—a *lost revenue adjustment mechanism (LRAM)* or *lost contribution to fixed costs (LCFC)*.[2] Under LRAM, a utility is allowed to recover revenues it has lost, not just due to any cause (as with decoupling) but specifically as a result of energy efficiency programs. Regulators calculate the energy savings associated with the efficiency measures installed. They then allow the utility to recoup the revenues it has lost due to those energy savings. Figure 1 shows how LRAM addresses a revenue shortfall.

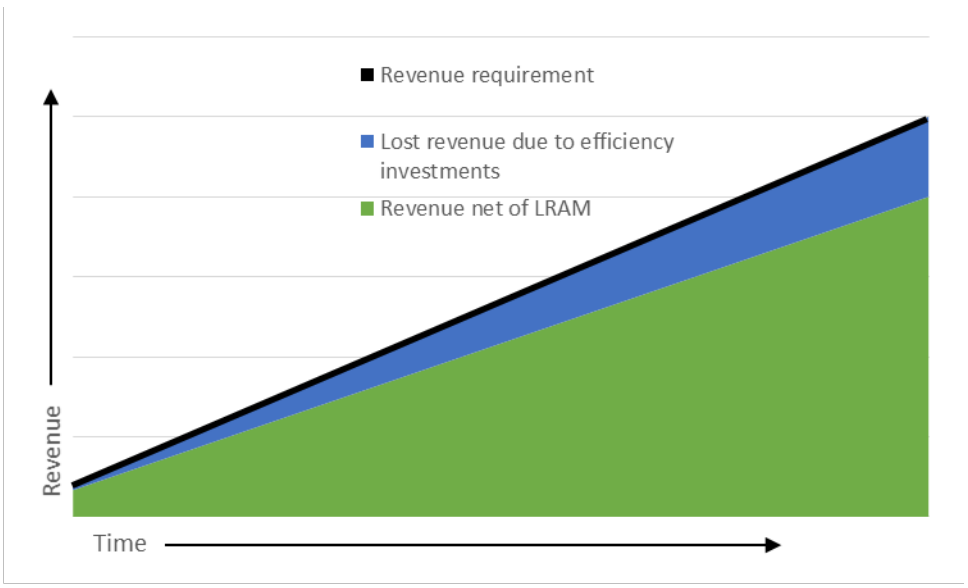

Figure 1. Theoretical application of LRAM to address revenue shortfall. A utility's revenue requirement is shown in black. In a traditional utility business model, savings from efficiency investments eliminate potential energy sales, thereby reducing a utility's revenue (shown in green). Under the LRAM approach, a utility calculates these savings and is able to capture lost revenue, shown in blue.

There are key distinctions between LRAM and decoupling. First, LRAM requires a utility to estimate energy savings resulting from efficiency programs over a given time period.[3] Decoupling requires no such estimation because its adjustments are based on actual sales volume (which is easily observable) rather than projected savings. Second, unlike decoupling, LRAM is typically not symmetrical. As discussed above, decoupling results in customer refunds if the utility sells more energy than expected, and surcharges if it sells less. With LRAM, the utility may recover revenues lost due to efficiency programs, but

[1] We consider a state to be decoupled when the mechanism is in place for at least one major utility.

[2] We use the term LRAM throughout this paper, although there are other names for this mechanism.

[3] In practice, states estimate energy savings to varying degrees, with some putting greater focus on evaluated savings than others.

regulators do not make adjustments if the utility sells more energy than predicted in the test year. Figure 2 illustrates the potential for over-earning built into the structure of LRAM.

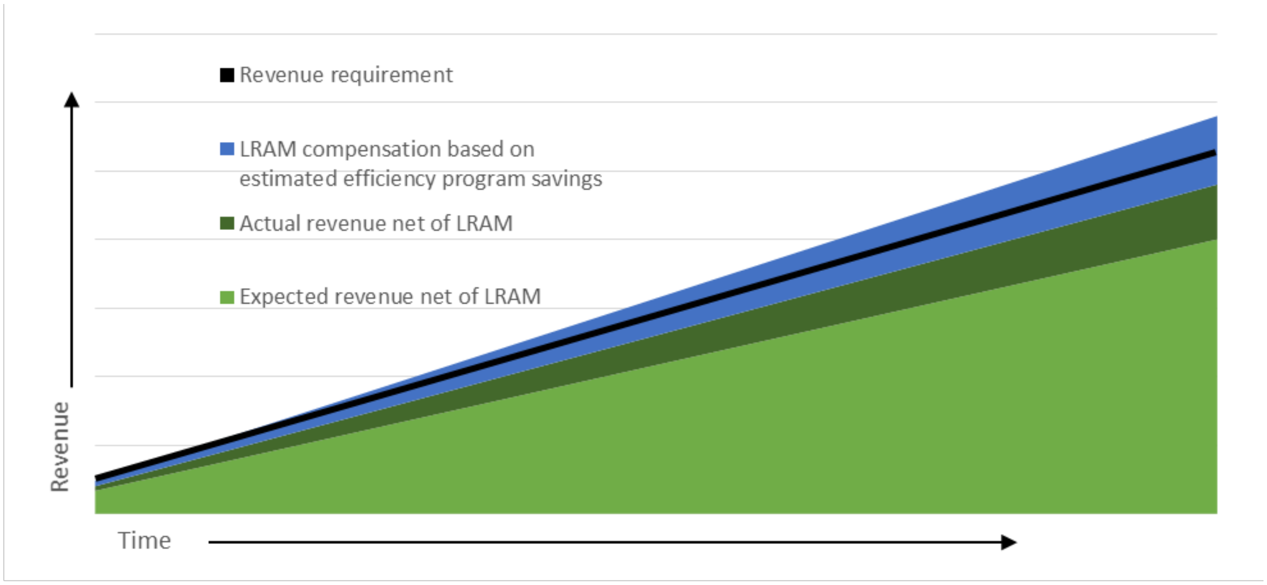

Figure 2. Potential problem with LRAM if sales are above forecast after energy efficiency programs are enacted. The dark green area is revenue above what was predicted in the test case. By evaluating savings generated through efficiency, utilities are often still able to recover the total amount of lost revenues shown in blue, even the portion above the revenue requirement.

Unlike decoupling, then, LRAM does not completely remove the link between a utility's sales and its revenues. As can be seen in figure 2, a utility could have the incentive to boost sales above the level originally forecast to allow recovery of authorized revenues beyond the revenue requirement. Some states have tried to design LRAM policies to address this issue. For example, in Nevada, utilities are explicitly prevented from over-earning and in recent years have refunded excess revenues to customers.

One more initial point should be made about LRAM. This mechanism does not reimburse utilities for the cost of energy efficiency programs; rather, it makes them whole for revenues they have lost as a result of selling less energy. Analysts should not regard LRAM as a cost of energy efficiency, and they should not include it in cost calculations, for example when they compare the cost of energy efficiency with that of other resources. This mischaracterization becomes especially misleading when LRAM dollars compound over time if there are long intervals between rate cases. We discuss this issue in the section below on the "pancake effect."

LRAM in the States

In recent years, many states have adopted the LRAM approach to address utilities' throughput incentive. In 2011, an ACEEE paper detailed the experiences of several states with LRAM in place (Hayes et al. 2011). The authors found 13 states with current or pending LRAMs for at least one electric or natural gas utility, but only 4 states with more than a year of experience. Since that time, more states have adopted this type of regulatory mechanism, and many have had several years of experience. Currently, 17 states have LRAMs in place for at least one major electric or gas utility (figure 3).[4]

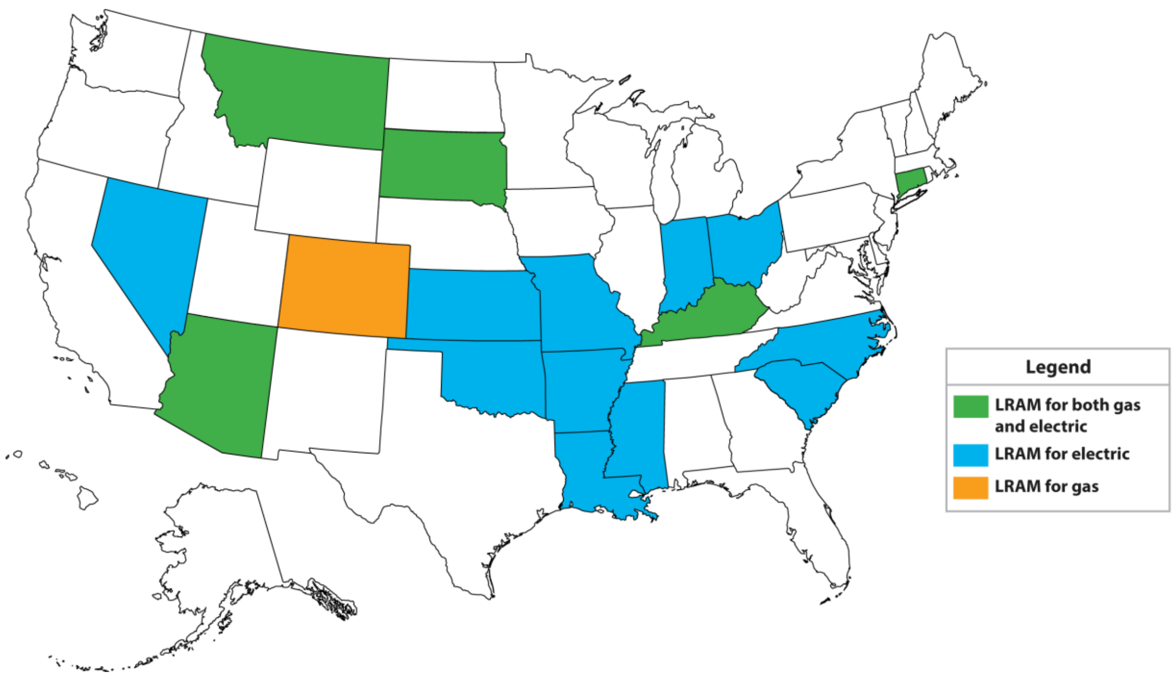

Figure 3. States with at least one utility with an LRAM currently in place. Note that decoupling or other rate adjustment mechanisms may also be in place for some utilities in these states. In Connecticut, CL&P, the only electric utility in the state with an LRAM, included a decoupling mechanism in its most recent rate case.

ACEEE tracks LRAM and decoupling policies through its *State Energy Efficiency Scorecard*.[5] Information on utility business models is also maintained in the ACEEE State and Local Policy Database.[6] However we have not examined these policies in detail since 2011 (see Hayes et al. 2011). This report expands on our prior research, describing state experiences to date and detailing the outcomes. We describe the current landscape of lost revenue adjustment across states, summarize the available data, discuss our results, and offer recommendations.

Methodology

To begin research for this report, the authors sent a questionnaire to public utility commissions in each state with an LRAM in place (see Appendix C). We asked commission staff to submit both qualitative and quantitative data on mechanisms in place for electric utilities, gas utilities, or both. In total, we distributed 24 questionnaires. Through the data collection process, we learned that six states had policies that did not fit our definition of a lost revenue adjustment mechanism. We did not include these states in this report. Four

[4] LRAM is currently pending in Louisiana but has not yet been implemented.

[5] Most recently, see Gilleo et al. 2014.

[6] http://database.aceee.org/

states did not complete the questionnaire. Many other states returned the questionnaire but indicated that at least some relevant data were unavailable or unclear.

Using the questionnaires as a starting point, we conducted interviews with states selected to represent a variety of geographical locations and regulatory experiences. Interviews with public utility commission staff, consumer advocates, utility representatives, and efficiency advocates added context to the technical details of the LRAMs in place in each of these states. We also parsed additional information from utility dockets when necessary. Using case studies and the quantitative data available, we developed a set of observations regarding state experiences with LRAMs.

Through this process we found that LRAM is being implemented in a variety of ways across the states. Because of the differences in regulatory structures and true-up timelines and the nuances in spending and savings data submitted, we cannot make apples-to-apples comparisons of dollars awarded under LRAMs. However we do present quantitative data where they are available to illustrate both trends and variation.

Each state profiled in this report treats lost revenue differently. While quantitative data are useful for understanding patterns and variances, it is also important to understand the subtleties of both policy design and policy priorities in each state. In the sections below, we describe state experience with LRAM, discuss our findings, and offer recommendations.

LRAM: History and Current Practice

Historical Perspective

Lost revenue adjustment mechanisms are not new. In the 1980s and early 1990s, several states enacted policies allowing utilities to recover revenues lost from energy efficiency programs. However state experience with LRAM during this period was fraught with long and contentious proceedings. LRAM led to price increases, and lost revenue dollars recovered approached the amount of total dollars invested in energy efficiency (Hayes et al. 2011). These issues led many states to abandon the policy.

Historic Example: Minnesota

A prominent example of issues associated with lost margin recovery can be found in Minnesota, where an LRAM policy adopted for the state's electric utilities in 1991 was creating rapidly escalating LRAM costs for ratepayers. Due to the accumulating lost revenues between rate cases (see the discussion of pancaking that begins on page 11 of this report), the cost for lost revenues to ratepayers in 1997 was equivalent to 60% of the energy efficiency program costs, and climbing. In a filing to the Minnesota Public Utilities Commission (MPUC), the Minnesota Department of Public Service (MDPS) cited the following concerns in Docket No. E002:

- The period between rate cases is much longer than that envisioned when [the lost margin policies] were approved, significantly increasing the level of lost margins accrued.
- Lost margins increase rates without any tangible benefit to ratepayers.
- True lost margins are shrinking because, in the long run, "fixed" costs become variable costs.
- Utilities have growing opportunities to sell their saved energy on the wholesale market.

The MDPS noted:

> [I]t has now been 12 years since Otter Tail Power filed a rate case, 5 years since NSP-Electric filed, 4 years since Minnesota Power filed, and 3 years since Interstate filed. The frequency of rate cases is an important issue. The longer time lag has increased lost margins significantly, thereby raising the costs of electric utilities' DSM investments to ratepayers.

The MDPS added, "Clearly, [lost margin recovery was] intended to compensate utilities for short-term revenue losses between relatively frequent general rate proceedings. They were not intended to provide long-term windfall gains to shareholders."

For the state's largest utility (Northern States Power), while the energy efficiency program budget actually declined somewhat from 1994 through 1997, the annual lost revenue recovery increased eightfold over that time period. The MDPS recommended ending the LRAM policy after that case, and the MPUC subsequently agreed (Docket No. E002/M-98-443).

Despite the outcomes in the 1980s and 1990s, in recent years a number of states have again begun to adopt LRAM as a tool to encourage energy efficiency. The policy is meant to address utilities' concerns about revenues lost (contributions to fixed costs) as a result of customer energy efficiency programs. ACEEE's previous review of LRAM (Hayes et al. 2011) found that although the use of LRAM was increasing, there were limited data available to assess both the types of approach and the outcomes. The report also noted that no standard approach to implementation of an LRAM had emerged. Several years later, we see that the variation in these policy mechanisms is just as great. In Appendix A, we outline the details of lost revenue adjustment mechanisms currently in place in the United States.

Our research also brought to light several states where it was unclear whether a policy could be categorized as an LRAM. For example, Georgia allows utilities to earn an "additional sum," and its state code directs the utilities commission to "consider lost revenues…between the utility and its retail customers." While there had been some question as to whether Georgia's additional sum included the recovery of lost revenues, state contacts preferred to describe their regulatory mechanism as something closer to a performance incentive.[7] Alabama's Rate Stabilization and Equalization (RSE) Mechanism also is similar to an LRAM, although its purpose is to smooth customers' rates rather than remove the throughput incentive. We did not include Alabama's RSE or Georgia's additional sum calculation in this study. Wisconsin had a pilot program similar to Alabama's RSE from 2009 to 2013 and is likewise not included in this study. The mechanism captured over- and under-collections of Wisconsin Public Service Company's gross margin due to any cause, based on the number of bill counts. We also did not include Wyoming in our analysis of LRAMs. Wyoming does have a mechanism in place that allows Montana Dakota Utilities to recover lost revenues, but this mechanism applies only to load management programs. Since the LRAM does not apply to energy conservation efforts, we omitted it from our analysis.

Other states have had LRAMs in place in the past but have since eliminated these policies, opting instead to allow utilities to meet revenue requirements through decoupling or other rate design methods.[8] We did not include such states in our research for this report, focusing instead on policies currently being implemented.

BY THE NUMBERS

We asked states to submit information on lost revenue dollars eligible for recovery by utilities in the two most recent program years, along with information on program costs and annual savings from energy efficiency programs for each of those years. Not all states were able to provide this information. In total, we received data covering 32 utilities in 17 states, most outlining program expenditures, annual savings, and eligible LRAM dollars in years 2012 and 2013, with a few results from 2011 and 2012. Figure 4 shows eligible dollars for recovery from lost revenue associated with electricity efficiency programs.[9] LRAM dollars are normalized over electricity savings.

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[7] See Nowak et al. (2015) for more information on Georgia's and other states' performance incentives.

[8] For example, Hawaii terminated its LRAM mechanism in 2010 in favor of decoupling. Minnesota recently approved a decoupling mechanism.

[9] Note that in certain states, utilities may not *actually* recover all eligible dollars. For example, in Nevada, utilities are instructed to return lost revenue dollars to ratepayers after exceeding revenue requirements.

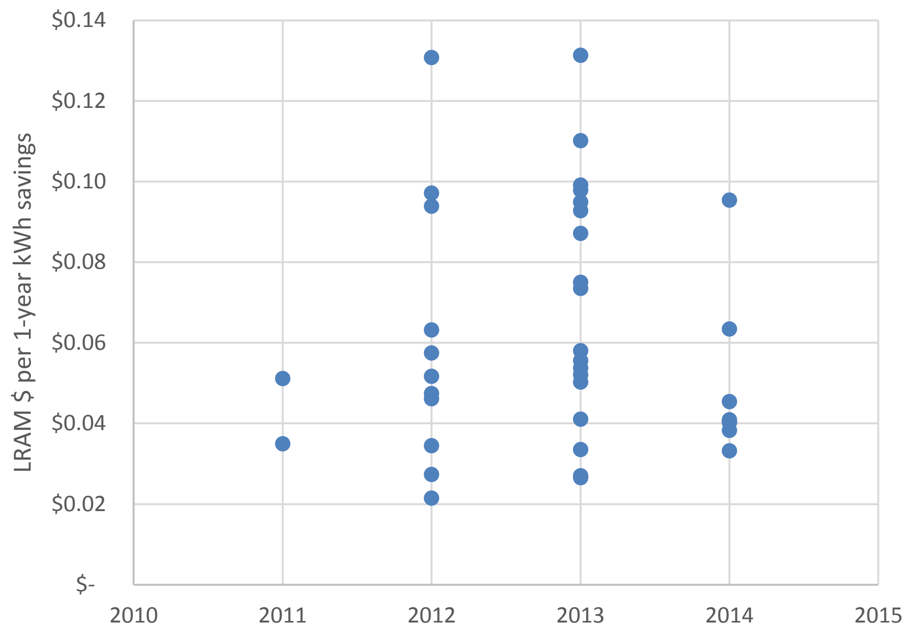

Figure 4. Lost revenue adjustment dollars recovered per kWh savings for electricity efficiency programs. Savings are annual one-year program savings. Data supplied by state public utility commissions. Note that not all states were able to provide data.

The amount utilities were eligible to recover per unit of electricity saved ranged from $0.02 per kWh to $0.13 per kWh, with a median of $0.05 per kWh. This range speaks to several factors that may influence LRAM collection:

- Different rate structures put varying amounts of rates in fixed and variable charges. The more that bills vary with consumption, the higher the LRAM rate will be.
- A utility's fixed charges also play a large role. Some utilities are vertically integrated, so LRAMs capture generation fixed costs. Other states have distribution-only utilities, so customers are not assessed generation-related fixed costs in LRAMs.
- States also have different limits in place for the time over which a utility may collect LRAM dollars for a given program year. In some cases, regulators were not able to say definitively that LRAM dollars were associated with a particular year's programs. In such situations, it is possible that recovery is also associated with additional savings from previous programs, making recovery amounts seem artificially high in comparison with energy savings.

Figure 5 shows eligible dollars for recovery of lost revenues associated with natural gas efficiency programs. LRAM dollars are normalized over natural gas savings.

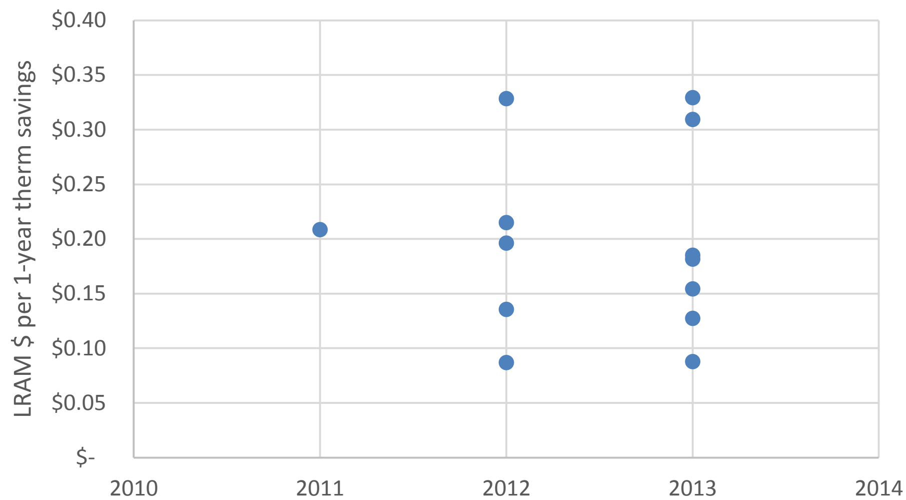

Figure 5. Lost revenue adjustment dollars recovered per therm savings for natural gas efficiency programs. Savings are annual one-year program savings. Data supplied by state public utility commissions.

As with LRAM dollars associated with electricity efficiency programs, we see notable variation in LRAM dollars eligible for recovery per unit of natural gas savings. Eligible recovery amounts range from $0.09 per therm up to $0.33 per therm, with a median of $0.19 per therm. Here too, differences in base rates may play a role. The inability to separate total lost revenues to show the amount associated with individual recovery years may also inflate figures.

The range in LRAM dollars per energy unit is dependent on the fixed costs for a given utility, which vary significantly based on a number of different factors. At their most basic, lost revenues are typically calculated as follows:

Lost revenues = Retail rate – Short-term avoided costs

Thus, lost contributions to fixed costs are directly dependent on the factors that make up utilities' base rates, and both fixed and variable costs can have an effect on the lost margin. Fixed costs can include investment costs; unavoidable costs of maintaining power plants, transmission lines, and other infrastructure; and other non-avoidable operating costs like personnel (NARUC 2007). These fixed costs may vary for a number of reasons. Simple avoided costs, as shown in the calculation above, typically represent fuel cost, although they are rarely so straightforward in practice. RAP (2011) calls these costs production costs and notes that in addition to fuel, they can include purchased power expenses, operation and maintenance costs, and transmission expenses. These too can vary by utility and region.

A variety of factors can influence lost revenue calculations, both in terms of a utility's overall fixed and marginal costs and in terms of the choices regulators make in designing the lost revenue calculation. Many states include separate LRAM calculations for each rate class. Some states factor in peak demand reductions in addition to changes in overall energy consumption.

Perhaps more telling is the comparison of a utility's program costs to the amount of lost revenue it claims each year. Figure 6 shows how the LRAM dollars recovered annually by electric utilities compare to annual program costs.

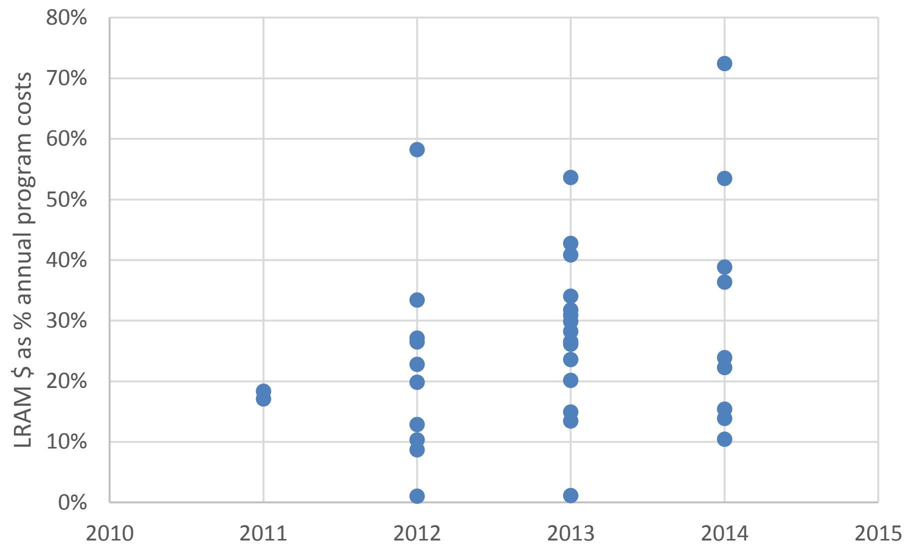

Figure 6. Lost revenue dollars eligible for recovery as a percentage of electricity efficiency program expenditures

Among the electric utilities we surveyed, LRAM dollars as a percentage of program costs varied widely. At the low end, dollars collected for lost revenue were equivalent to only about 1% of electricity efficiency program costs in a given year.[10] Median recovery was 25% of annual program costs. However, for one utility surveyed, lost revenues recovered were equivalent to more than 70% of program costs. It is likely that in such cases, several years of recovery were rolled into a single rate case. Thus, the LRAM dollars reported were not completely tied to a single year of efficiency programs, but rather accrued due to savings achieved over multiple years.

THE PANCAKE EFFECT

As noted above, LRAM dollars are not additional costs of efficiency programs. Rather, they reflect the collection of already authorized utility system fixed costs, and their collection is meant to bring the utility back in line with its revenue requirement. However there is the potential for over-earning under an LRAM if the mechanism is not well designed and closely monitored and if rates are not regularly reset to reflect updated electricity sales forecasts and utility system costs.

Efficiency measures generate savings over time. Absent intervention, and with everything else equal, lower consumption will cause a utility to not collect its fixed costs of providing service until the next rate case. In a rate case, rates are set based on current or projected

[10] This result was a for a very small efficiency program. The lowest dollar amount collected for a larger program was about 9% of program costs.

future consumption, taking into account already existing energy efficiency. LRAMs make a utility whole in the periods between rate cases. But if rate cases are few and far between, balances in a LRAM account can build up, because each year the utility is capturing the revenue lost not only from measures implemented in that year, but also from energy efficiency measures put in place since the last time rates were set. This so-called pancake effect would impose substantial additional costs on customers if many years pass between program implementation and the next rate case. This hypothetical scenario is illustrated in figure 7.

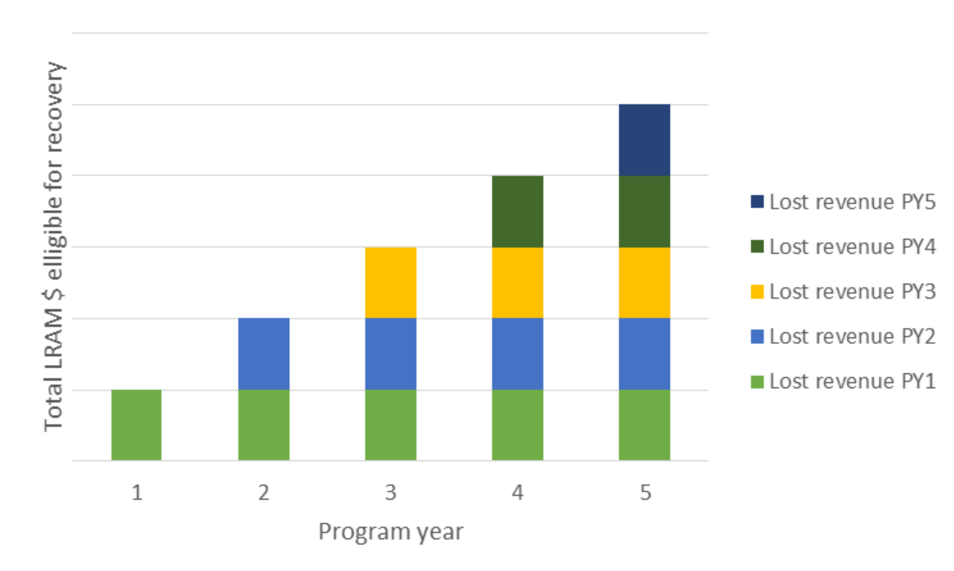

Figure 7. Scenario in which lost revenues pancake over a five-year period between rate cases. Lost revenues typically reset between rate cases, and rates are recalculated on the basis of a more current test year. For these reasons, timely rate cases help minimize pancaking and over-earnings.

As suggested above, regular rate cases can help minimize the pancaking effect, since regulators and utilities will take the effects of past years' energy efficiency programs into account in their predictions of future sales. States often set requirements stipulating the frequency with which utilities must come in for rate cases and reset lost revenues. Figure 8 shows the length of time, according to our research, that utilities typically collect lost revenues associated with a particular program year.

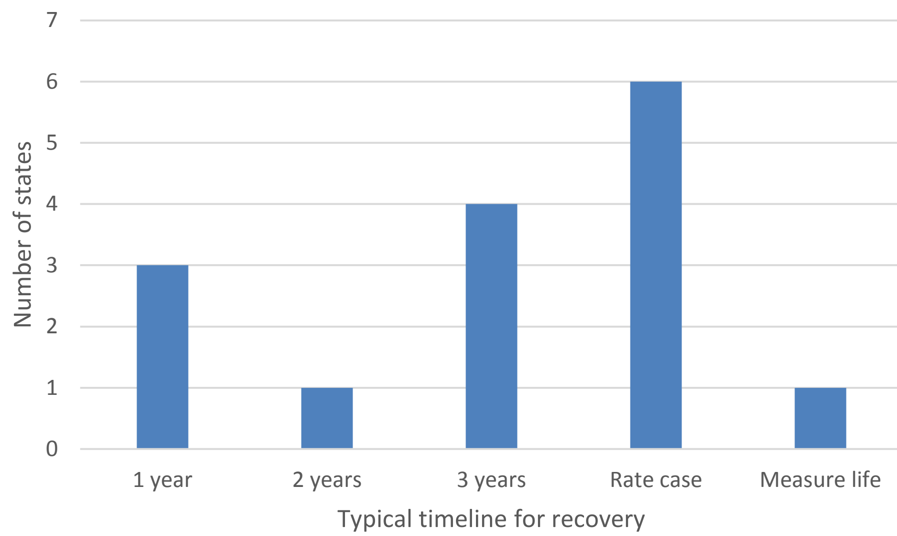

Figure 8. Length of time over which lost revenue are typically recovered for a single program year. Data from state responses.

It is most common for states to limit recovery to one to three years, although many states allow utilities to recover lost revenue for an indefinite period of time, resetting lost revenues during base rate cases. Respondents indicated that in these cases, although rules might not be in place specifying the allowable length of time between rate cases, utilities tend to bring them forward every two to three years. If there is no time limit on recovery of LRAM dollars (or rates are not reset to halt the LRAM collection), those dollar costs can pancake year after year. This has happened in some states, leading to a rejection of the LRAM policy.[11] Only one state indicated that utilities are able to recover lost revenue over the full life of an efficiency measure, regardless of rate cases.

It is also important to note that the pancake effect is an added challenge for regulators. Few regulatory staff were able to parse out lost revenues associated with a particular year's efficiency programs. Since LRAM dollars tend to flow into a single efficiency rider from several years' worth of programs, it can be difficult for regulators to judge the reasonableness of a utility's request for lost revenue. Development of reliable tracking systems is costly in terms of both time and money, and public service commissions are often understaffed and underfunded. Due to these constraints, quantifying the dollars associated with specific program years is often a near-impossible feat.

DOES LRAM FACILITATE GREATER ENERGY EFFICIENCY?

The fundamental purpose of an LRAM policy is to facilitate greater investment in energy efficiency by a utility. The LRAM is meant to address utility concern about lost contributions to fixed costs due to energy efficiency programs. Data on energy efficiency program performance available from ACEEE's annual *State Energy Efficiency Scorecard* allow

[11] See the Minnesota example above.

us to examine whether electric utility LRAMs are associated with greater energy efficiency accomplishments.

For this analysis we focused on two key indicator variables (energy efficiency spending as a percentage of total revenues, and energy efficiency kWh savings as a percentage of retail sales), using the most recent year (2013) for which complete data were available. Many unique factors in a state or utility will influence utility behavior regarding energy efficiency programs, but it is nonetheless useful to look at how patterns of performance vary across many states under different policy conditions.

Due to a small sample size, we were limited in our analysis and relied on data visualization to make inferences. To begin, we compared states that had an LRAM policy in place for at least one utility in 2013 with states that had no LRAM or decoupling policy in place. (States with decoupling were excluded for the first analysis because decoupling is intended to address the same issue as LRAM.) No clear pattern emerges when comparing efficiency budgets between these two groups of states. While the spread between maximum and minimum budgets is larger for states with no revenue adjustment mechanism, median budgets are about the same (0.85% and 0.95%). Figure 9 shows efficiency budgets for these groups of states.

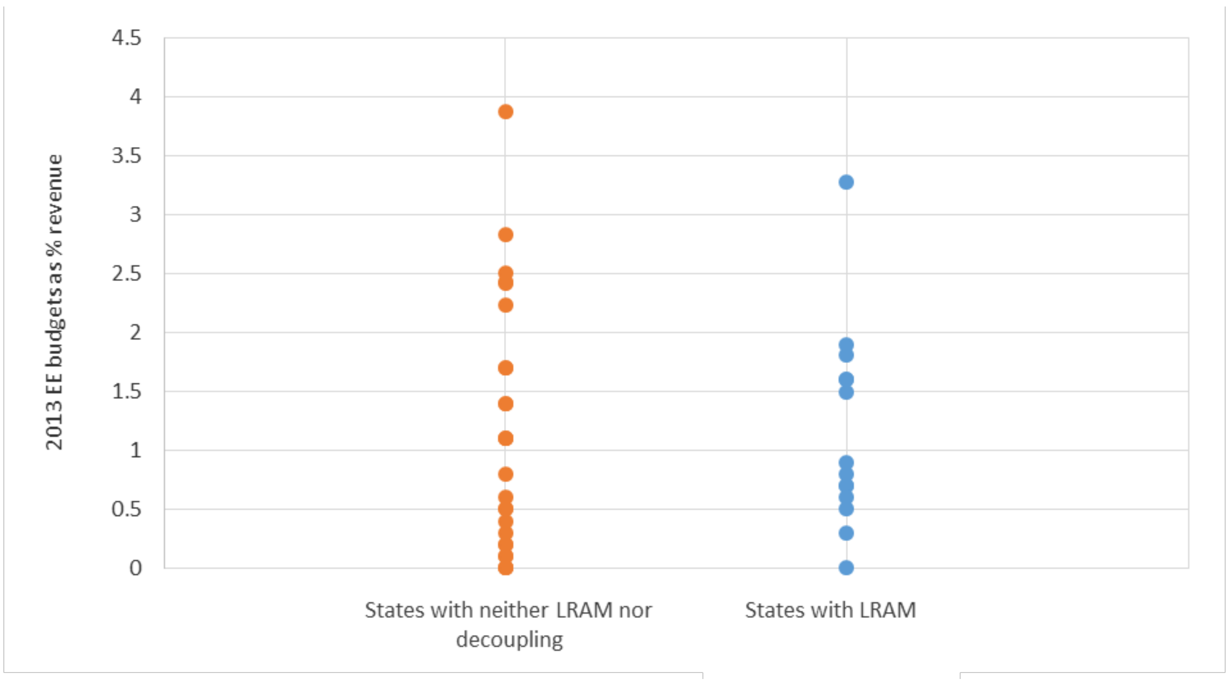

Figure 9. Efficiency budgets in states with LRAM compared with states having no revenue adjustment mechanism

Figure 10 shows 2013 savings data for this same set of states. Median statewide electricity savings for states with LRAM was 0.55% in 2013, compared with median savings of 0.3% in states with no revenue adjustment mechanism.

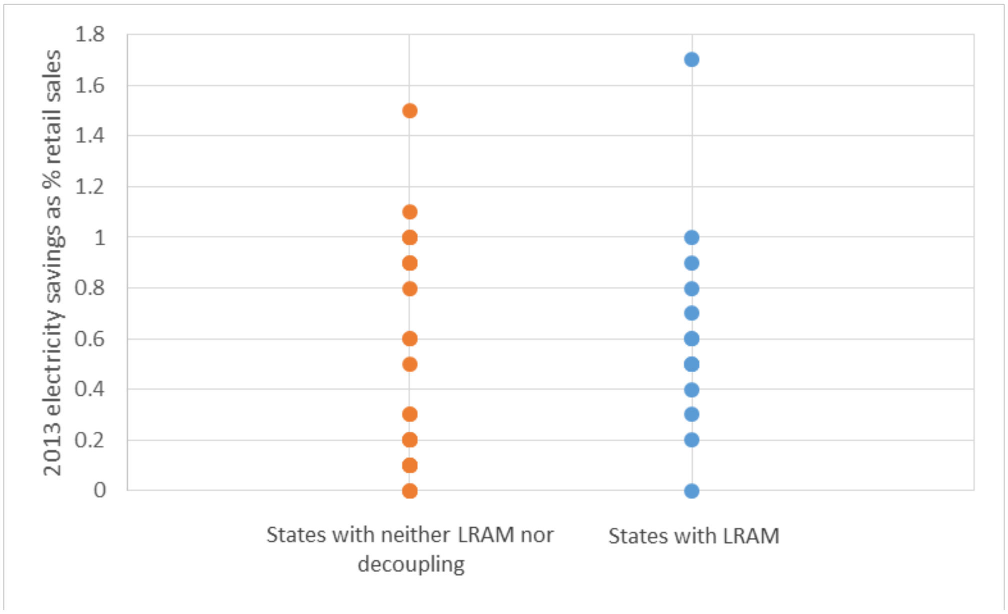

Figure 10. Electricity savings in states with LRAM compared with states having no revenue adjustment mechanism

We then compared states with LRAM against states with at least one electric utility decoupled. Figure 11 shows 2013 electricity efficiency budgets for these states.[12]

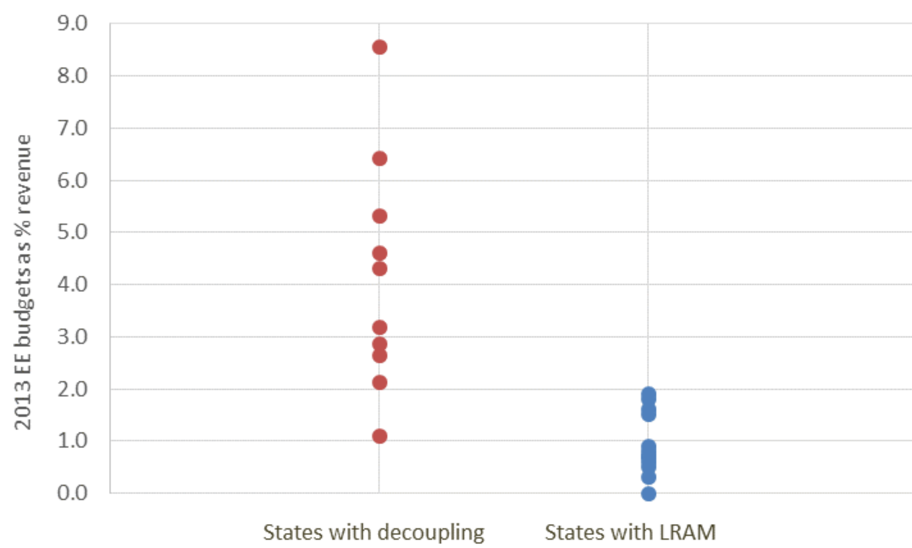

Figure 11. Electricity efficiency budgets in states with LRAM compared with states that have decoupling

Here, we do see some difference between spending in states with decoupling and those with LRAM. Specifically, states with decoupling appear to be spending more on energy efficiency

[12] States in which at least one utility is decoupled *and* one utility has an LRAM in place were excluded from this analysis.

relative to revenue. We see a similar pattern in our comparison of electricity savings, shown in figure 12.

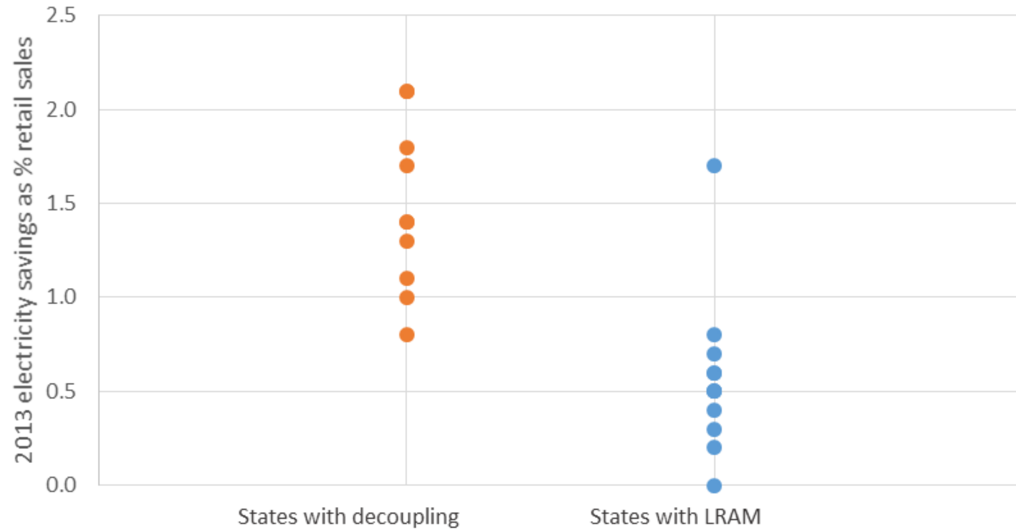

Figure 12. Electricity savings in states with LRAM compared with states that have decoupling

Median incremental electricity savings in 2013 was 1.4% for states with decoupling, compared with median savings of 0.5% for states with LRAM, a stark difference. However, it is important to note that all but one of the decoupling states also had an energy efficiency resource standard (EERS) policy in place, which we have found to be the dominant policy associated with greater energy efficiency spending and savings. To control for that factor, we did two additional analyses. First, we looked just at states with an EERS, charting efficiency budgets for states with LRAM and for those with decoupling. Figure 13 shows the results of this analysis, which included only a small set of states.

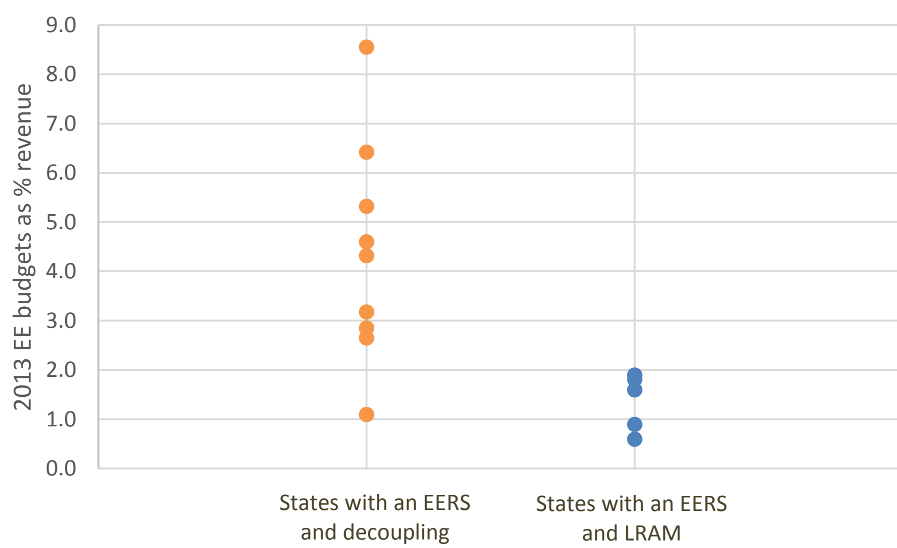

Figure 13. States with LRAM compared with states with decoupling when an EERS policy is in place

Figure 14 shows the results of this analysis for statewide electricity savings in 2013.

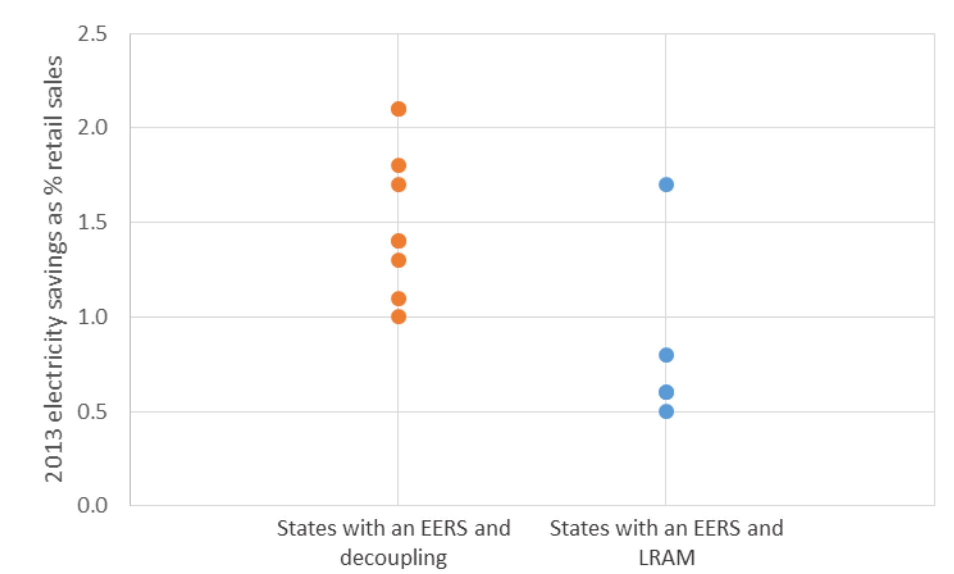

Figure 14. States with LRAM compared with states with decoupling when an EERS policy is in place

Here also, data visualization indicates that when an EERS is in place, states with decoupling tend to have higher electricity efficiency budgets and savings than states with LRAM. However the directionality of cause and effect may be an issue, and other factors could also play a large role, such as specific EERS targets in these states. Year of EERS adoption may also account for some of the variation between groups. Idaho is the only state without an EERS in place to have at least one decoupled electric utility in 2013, so it was not possible to compare budgets for states with decoupling and states with LRAM when no EERS is in place.

These findings are obviously not determinative for every state or utility. Still, the results suggest that, in aggregate, having an LRAM policy is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than can be found in states without an LRAM policy.

Discussion

In its second incarnation, LRAM appears to face many of the same issues that it did in the early 1990s. In its *National Action Plan for Energy Efficiency* (EPA 2007), the US Environmental Protection Agency (EPA) laid out the following pros and cons of lost revenue adjustment mechanisms:

Pros:

1. Removes disincentive to energy efficiency investment in approved programs caused by under-recovery of allowed revenues.
2. May be more acceptable to parties uncomfortable with decoupling.

Cons:

1. Does not remove the throughput incentive to increase sales.
2. Does not remove the disincentive to support other energy saving policies.
3. Can be complex to implement given the need for precise evaluation, and will increase regulatory costs if it is closely monitored.
4. Proper recovery (no over- or under-recovery) depends on precise evaluation of program savings.

The case studies presented in Appendix A further illustrate each of these points. While many states have reported benefits from LRAM policies, many of these same states have also noted the flaws. Moreover, it is not clear that states have been able to strike the necessary balance between accuracy in valuing lost revenues and efficiency in administering the policy. Below, we identify a number of factors that states should weigh in considering adjustments to current policies or deciding whether an LRAM is an appropriate regulatory tool to pursue in the future.

AN LRAM CAN BRING PARTIES TO THE TABLE

Energy efficiency *does* reduce utility sales, and utilities *should* be able to recover their authorized fixed costs. Decoupling is the simplest way to ensure that a utility meets its revenue requirement even if other factors dampen sales. But in many states, key parties view decoupling unfavorably.[13] Utilities often push back against decoupling proposals because they feel they should be allowed some level of reward for the risks they often must bear.[14] Some consumer advocates have also worked to block decoupling proposals, citing added costs, reduced utility risk at the expense of additional risk placed on consumers, and a general opposition to automatic rate adjustment mechanisms.

In many states, LRAM has been used as an alternative to decoupling to make utilities whole after investments in energy efficiency. Utilities may be supportive of LRAM because there is the potential to accrue revenues beyond the regulator-determined revenue requirement, resulting in pure profit for the utility.[15] Since LRAM expressly requires the calculation of energy savings from efficiency programs and omits other variables like weather, consumer advocates may also feel better about allowing utilities to recoup these costs. While LRAM is a less desirable solution than decoupling, it can bring parties to the table in circumstances where decoupling may not be feasible.

GOOD EM&V IS IMPORTANT

Allowing utilities to recover the revenues lost due to implementation of efficiency programs necessitates the need for accurate evaluation of programs. In order to prevent overcharging

[13] See RAP (2011) for a complete discussion of the arguments often made against decoupling.

[14] See Vilbert et al. (2014) for a discussion of the impact of decoupling on the cost of capital. The study finds that decoupling is not associated with a decreased cost of capital.

[15] Some states have limited lost revenue recovery to prevent over-earning. For example, see the Nevada case study in Appendix B.

customers or undervaluing a utility's lost revenues, utilities and regulators need to get the savings right. Evaluation of savings is controversial in many of the states in which we conducted interviews. Though evaluation procedures were already in place for efficiency programs in many states, when lost revenues were at stake the scrutiny became far greater.

Key parties were reticent about evaluation methods for a variety of reasons. Consumer advocates in some states were wary of "estimations" of savings, saying that it was impossible to judge whether savings were actually achieved. Commissions also noted that changing evaluation methodologies led to lengthy back-and-forth exchanges between utilities and regulatory staff. Ultimately, evaluation procedures do rely on some level of sampling, statistical analysis, and estimation. There may be additional difficulties in states with net savings requirements, as evaluation efforts need to not only focus on engineering estimates but also project what would happen in the absence of programs.[16] Since it is impossible to weigh the results of efficiency programs against a hypothetical (i.e., electricity consumption absent utility-run efficiency programs), it is important that all parties understand and agree to evaluation procedures. The evaluation process should be rigorous and transparent, with appropriate checks along the way.

In a few states we surveyed, there was little oversight of evaluation methods or results by the utility commission. While this led to efficient, uncontested rate case and demand-side management (DSM) proceedings, it also eliminated an important checkpoint for accuracy. We found very few examples of states that had reached a middle ground between accuracy and efficiency. Including stakeholders in discussions of evaluation procedures, setting clear evaluation and reporting guidelines for utilities, and including independent evaluators in the process may help states find this balancing point. Finally, evaluation techniques continue to improve and evolve as new technologies open the door for real-time analysis of certain program types. Embracing these technological innovations may simplify and streamline EM&V processes.

TIMING MATTERS

Timing is critical to precise, efficient implementation of an LRAM. Since energy efficiency program decisions and rate-making decisions are necessarily intertwined in states with an LRAM in place, having these two functions occur at the same time can help streamline processes. In many of the states we spoke to, all parties expressed the difficulty of dealing with lost revenues when rate cases were dealt with separately from DSM decisions. In some states, this increased the number of true-ups needed to recover a single program year's lost revenues. It also ate away at staff time. Several other states with multiyear experience implementing an LRAM had adjusted timelines for rate-making and DSM decisions so that the two proceedings occurred jointly.

While timing of rate cases and DSM proceedings is important from a logistical standpoint, perhaps more important from a financial standpoint is the time between rate cases. Since

[16] Net savings calculations factor in the impacts of free riders and spillover on efficiency programs. Therefore, not all savings calculated using engineering estimates may be attributed to a utility. Net savings are often about 90% of gross savings (Gilleo et. al 2014), but these ratios can vary greatly from state to state.

adjustments to lost revenue rely on a test year, the more up to date these test cases are, the more accurate the calculation of lost revenue can be. Frequent rate cases also avoid the issues associated with pancaked savings, as discussed above. When revenue adjustments are made infrequently, the result is a large sum of money passing from consumers to utilities. Whether or not this transfer is legitimate, the impression it creates can be a matter of contention among utilities, regulators, and consumer advocates. Policies that cap lost revenue to two or three years can avoid this problem.

AN LRAM ALONE WILL NOT FULLY INCENTIVIZE EFFICIENCY

Lost revenue adjustment is just one (optional) approach to aligning utility incentives with investment in energy efficiency. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales, it will do little to *encourage* investment in energy efficiency unless combined with other policy levers. Our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Setting energy savings targets through an EERS and implementing performance incentives tied to specific energy saving levels are ways that regulators can encourage prioritization of energy efficiency.[17] Evaluating energy efficiency in the same manner as other supply-side resources during resource planning also should help to encourage energy efficiency utility investments.

Similarly, an LRAM does not eliminate a utility's throughput incentive. The LRAM compensates a utility for energy savings achieved by its programs, but if a utility can sell more energy while also delivering efficiency programs, it may be able to recover dollars beyond its revenue requirement. Thus, an LRAM can result in a utility's pursing energy savings with one hand while seeking additional sales growth with the other.

Additional Questions and Further Research

RATE IMPACTS OF LRAM

The rate impacts of decoupling are well known due to careful research and tracking over the past several years (most recently Morgan 2013). However a similar analysis has not yet been completed for LRAM. Such research would be complicated but would better show the impacts of a policy that could be effective at its best but overly generous at its worst. Data on the impacts of dollars recovered through lost revenue are murky. Public utility commission staff are often unable to untangle LRAM dollars to align dollar amounts with individual program years. However future research should endeavor to tease out these intricacies in order to better understand the rate impacts of LRAM policies. Then more straightforward comparisons with decoupling could be made—both in terms of overall savings achieved under the policy and in terms of the financial impacts on ratepayers.

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[17] For an overview of EERS policies, see Downs and Cui (2014). For further discussion of performance incentives, see Nowak et al. (2015).

EFFECTS OF OFF-SYSTEM SALES

Over the course of this study, many utilities noted that efficiency programs left a hole in their revenues that LRAM was able to close. However utilities have other avenues for selling unused energy and may still earn profits from power that is not provided directly to their customer base. For example, most utilities can sell unused energy off system. These sales allow companies to make profits above the allowed revenue requirements and to make up lost revenues from several different factors. Some states allow shareholders to keep most of the earnings from off-system sales as profit, although many include requirements for crediting back some of the earnings to ratepayers (NARUC 2008). Off-system sales can be in the tens of millions of dollars and can be a huge part of a rate case (AEP 2014). If utilities are generating excess capacity and selling it off system, it may be that they are not truly losing revenues to efficiency but are simply earning those revenues outside of their customer base. In such cases, LRAM may be an additional earnings pathway, doing more than just making a utility whole. While this paper does not dive into the connection with off-system sales, future research should investigate how often these sales can effectively fill the hole that efficiency programs create in utility revenue, potentially negating the need for an LRAM.

Conclusion

Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best "third leg" of this stool. However it is also clear that decoupling is not always an option for states for a variety of reasons. In such scenarios, LRAM can be a temporary solution, addressing concerns over lost revenues and, possibly, helping to make parties more comfortable with the idea of full decoupling in the future.

But LRAM as a permanent policy fix is fraught with flaws. The regulatory burden is great, and the potential to shortchange customers and overcompensate utilities is ever present. As states gain more experience with LRAMs, problems continue to arise. Several states are striving for a simpler and fairer way to implement an LRAM that all parties will sign on to. In practice, an ideal LRAM possessing all of those qualities has yet to present itself. Finally, as noted above, having an LRAM policy in place does not currently appear to be associated with states' achieving higher levels of energy efficiency program spending or energy savings.

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Appendix A. Summaries of Currently Implemented LRAMs

State	Applicable utilities	Year authorized	Description of mechanism	Relevant rules and statutes
Arkansas	All electric and gas investor-owned utilities	2010	Arkansas rules allow recovery of lost contributions to fixed costs. These have been generally calculated as net savings times base rates, with savings being adjusted to take into account the timing (within the year) of measure installation and seasonality of the equipment.	Docket 08-137-U Order No. 14
Arizona	Arizona Public Service Company, UNS Gas, Tucson Electric Power Company, and UNS Electric	2012–2013	A lost fixed cost rate is determined at the conclusion of a rate case by taking the sum of allowed distribution and transmission revenue for each rate class and dividing each by their respective class adjusted test year kWh or therm billing determinants. The lost fixed cost rate is multiplied by the recoverable kWh or therm savings, by rate class.	Decision Nos. 73183, 73142, 73912
Colorado	Investor-owned natural gas utilities	2008	Each utility is to calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis with the supporting methodology and documentation for the calculation. The dollar per therm value, as approved by the Commission, is multiplied by the annualized number of therms saved as the result of the DSM program, as reported in the utility's annual report. The approved amount is recovered through the Demand Side Management Cost Adjustment (DSMCA) and applies to first-year savings only.	Code of Colorado Regulations (CCR) 723-4 Part 4
Connecticut	Connecticut Natural Gas, Southern Connecticut Gas, Yankee Gas, Connecticut Light & Power[18]	1995 for natural gas utilities, 2013 for CL&P	Lost sales from conservation program expenditures are tracked by program and rate class, matched with expenditures, and carried forward monthly for the balance of the Conservation Adjustment Mechanism (CAM) period. Lost revenues are estimated by taking cumulative savings (savings carried forward year to year between rate cases) and are applied a lost margin rate. The lost revenues are recovered through the CAM ($.046 Ccf). The energy savings are multiplied by a margin amount per unit, accumulated over the period, and results in the lost margin component of the CAM.	PA-13-298 Docket No. 93-02-04 Docket No. 93-03-09 Docket No. 11-10-03 Docket No. 14-03-01

[18] The most recent CL&P rate case (December 2014, Docket 14-05-06) included a decoupling mechanism per Connecticut Public Act 13-298.

State	Applicable utilities	Year authorized	Description of mechanism	Relevant rules and statutes
Indiana	Indiana Michigan Power, Northern Indiana Public Service Company, Vectren Indiana, and Duke Energy Indiana. Request for lost revenue recovery by Indiana Power & Light is currently before the commission.	1995	Each utility must propose a process for calculating an LRAM. The calculation must account for the impact of free riders and the change in the number of program participants between base rate changes and the revised estimate of a program-specific load impact that results from the utility's evaluation activities. Efficiency savings are measured by an independent evaluator. Revenue is recovered either annually of semiannually. Lost revenues are recovered for the life of the measure or until the company's next base rate case.	170 IAC 4-8-6
Kansas	Westar Energy	2011	The Kansas Corporation Commission will consider proposals from electric and gas utilities that include shared savings performance incentives on a case-by-case basis. KCC approved lost margin recovery for Westar Energy's Simple Savings program.	Docket 08-GIMX-441-GIV Docket 10-WSEE-775-TAR
Kentucky	All regulated electric and natural gas utilities	1995	Energy savings are calculated based on engineering estimates for either participants, projects, or programs and multiplied by the number of participants, projects, or programs. This is multiplied by the lost revenue factor (energy charges less fuel and other variable costs). There is typically a three-year sunset provision for lost revenues.	Kentucky Statute 78.285 Case No 2014-00271 Case No 2014-00003
Louisiana	Cleco Power, Entergy Gulf States, Entergy Louisiana, and Southwestern Electric Power Company (SWEPCO)	2014	The lost contribution to fixed cost (LCFC) level for each customer class is initially determined by multiplying the "Class LCFC Factor" by the projected annual level of energy savings to be achieved through each Quick Start program. Generally, the "Class LCFC Factor" is calculated by dividing 12 months of customer class energy charge-related revenue, including formula rate plan increases or decreases, by the class kWh sales from the same period. There is no ceiling for LCFC recovery, but there is an overall cap on Energy Efficiency Riders of $75 monthly as set forth by the EE rules.	Docket No. R-31106
Missouri	Ameren, GMO, KCPL	2013–2014	Utilities earn a percentage of net benefits calculated using deemed gross savings. Measure level annual energy and demand savings, measure lives, rates for avoided energy saving, and rates for avoided demand savings are deemed. Staff of the Missouri Public Service Commission performs a prudence review no less often than every 24 months to verify the calculation of net benefits used for the throughput disincentive mechanism. Lost revenues are recovered continuously through a rider.	SB 376 Case No. EO 2012-0142 Case No. EO 2012-0166 Case No. E0-2012-0009 Case No. E)-2012-0175

State	Applicable utilities	Year authorized	Description of mechanism	Relevant rules and statutes
Mississippi	Atmos Energy Corporation and Centerpoint Energy. Mississippi Power Company's cost recovery rider has not yet been approved.	2014	The company uses estimates for the coming year of savings due to energy efficiency programs normalized for weather and multiplies that number by the base rates less any customer charge. Lost revenues are recovered annually with a true-up to adjust for any under- or over-recovery.	Docket No. 2010-AD-2 Order Adopting Rule 29
Montana	NorthWestern Energy	2005	Lost revenues are recovered annually, with true-ups following the tracking period once actual numbers are available and again following a comprehensive report. Lost revenues are calculated by multiplying energy savings by an adjustment factor by rates. The adjustment factor takes into account free ridership and spillover rates.	Docket No. D2014.6.53 Docket No. D2012.5.49
North Carolina	Duke Energy Carolinas, Duke Energy Progress, Inc., and Dominion North Carolina Power	2007, with implementation orders in 2010–2013	The basic calculation of net lost revenues (NLR) is performed by multiplying net kWh (and, in some cases, kW) savings from each approved DSM/EE program by the billing rates that would have been applied to those kWh, if actually sold, and then reducing those lost revenues by the fuel cost recovery included in the billing rate, as well as nonfuel variable operations and maintenance expenses. In general, recovery of NLR for each installed measure is limited to a maximum of 36 months, subject to certain other limitations. NLR are also reduced by any net found revenues (or revenues associated with other activities that cause an increase in demand).	NCGS 62-133.9 Docket No. E-100 Sub 113
Nevada	Nevada Power Company and Sierra Pacific Power Company	2011, with updates in 2013–2014	The total lost revenue amount is estimated by first allocating estimated savings to each class that incurred the savings. The amount of savings is then multiplied by the general rate associated for that class to calculate implementation revenue. The implementation revenue for all the classes is summed along with the estimated lost demand revenue for a total lost revenue implementation revenue requirement. Lost revenues are estimated and a rate is put in place annually, but true-ups can occur for a single implementation year over several years. Lost revenue collection is suspended when a company is over-earning.	NRS 704.785(1)(a)(2) NAC 704.95225(1)(b) Dockets 10-10024 and 10-10025

State	Applicable utilities	Year authorized	Description of mechanism	Relevant rules and statutes
Ohio	Dayton Power & Light	2007	Lost revenue recovery mechanisms are determined on a case-by-case basis. Lost revenues are recovered through a rider and are calculated as the amount of kWh savings times the energy charge for each rate class. Variable costs are removed, and the amount is divided by expected sales for a future year. Lost revenues may be collected for three years. Decoupling is in place for Duke Ohio and AEP.	Docket 08-920-EL-SSO Docket 11-3549-EL-SSO Docket 11-0351-EL-AIR
Oklahoma	Public Service Oklahoma and Oklahoma Gas & Electric	2008	Lost revenues are calculated annually and are continued until the next base rate case or adjustment to rates, during which time the lost revenues are zeroed out and the appropriate volume reduction (adjustment) is included in that filing. Lost revenues are calculated by multiplying energy savings by an embedded cost factor. The embedded cost factor is calculated by taking the embedded costs approved in the most recent rate case (less fixed customer charges) divided by the kWh used in the cost study.	PUD Cause No. 200700449, Order No. 555302
South Carolina	Duke Energy Progress, Duke Energy Carolinas, and South Carolina Electric and Gas	2008, reestablished in 2013	Lost revenues are estimated annually and trued up once EM&V is available. Lost revenue can be collected for three years after installation or for the life of the measure, whichever is shorter. Lost revenues are calculated by multiplying energy savings by avoided costs.	S.C. Code Ann § 58-37-20 Docket No. 2008-251-E (Order No. 2009-373)
South Dakota	All investor-owned utilities	2009, most recent version in 2014	The lost revenues are negotiated as a percentage of approved budget spending. Savings are not included in the calculation of lost revenues, although they are estimated to ensure cost-effective programs. Recovery is limited to the year expenses are incurred.	Docket NG09-001 Docket EL11-002

Appendix B. Case Studies from Selected States

NEVADA

History

In 2009, the Nevada legislature passed SB 358. The law required the Public Utility Commission of Nevada (PUCN) to remove financial disincentives caused or created by the reasonable implementation of energy efficiency and conservation programs. The legislation specified that the rules had to include cost recovery for program expenses and removal of financial disincentives, and also noted that commission rules could—but were not required to—include financial incentives to help promote the participation of customers in energy efficiency programs. The legislature also stipulated that the regulation to be adopted by the PUCN could not authorize the utility to earn more than the rate of return authorized by the commission (NRS 704.785). In response to the 2009 legislation, the PUCN adopted rules creating a lost revenue adjustment mechanism.

The legislation was spurred in part by a changing population and economic dynamics within the state. Prior to 2009, the population of Nevada had been increasing dramatically from year to year, and electricity consumption had followed suit. During that time, the effect of lost revenues from efficiency programs was somewhat dampened by ever-increasing consumption. Utilities were allowed to book energy efficiency expenditures as an investment to earn a rate of return-on-equity 500 points higher than that authorized for supply-side investments. But lost revenues were not directly addressed. However, due to the recession, population growth stopped for a year and then resumed at a much slower rate. As a result, it became apparent that the state needed a more comprehensive approach to encourage further investment in efficiency.

Other Relevant Regulatory Features

Nevada has had a renewable portfolio standard (RPS) in place since 1997. In 2005, the RPS was revised, increasing portfolio requirements and allowing utilities to use energy efficiency to meet a portion of these requirements. Currently, cumulative energy efficiency savings can meet up to a quarter of the total standard in any given year. In other words, utilities may assign cumulative savings of about 6.25% of electricity sales toward meeting the requirement through 2025. While the RPS allowances may have spurred utilities to bulk up efficiency programs, utilities have now achieved the maximum level of efficiency allowed to count toward the requirement, meaning the policy has little effect in encouraging continued investments in efficiency. In 2013, the legislature voted to completely phase out efficiency from the RPS in coming years, further diminishing the effect the policy may have had in spurring investments in efficiency. Advocates and others have said there may be some discussion of a separate efficiency standard in coming years, but no specific docket has been opened on the subject.

LRAM Policy Details

The PUCN first authorized a lost revenue adjustment mechanism for electric utilities in May 2011 (Dockets 10-10024 and 10-10025). The state's two investor-owned electric utilities, Nevada Power Company and Sierra Pacific Power Company, both recover lost revenues from efficiency programs using the same mechanism type. The two utilities also share a parent company, NV Energy. Lost revenue in Nevada is recovered through the Energy

Efficiency Program Rate (EEPR). Program costs are recovered through the Energy Efficiency Implementation Rate (EEIR). Nevada uses the net savings achieved by energy efficiency and conservation programs in the determination of lost revenues.

The company begins with a revenue requirement for each customer class and removes customer charge revenue, customer-specific facilities revenue, and fuel costs from the class revenue requirement. The remaining dollar figure is divided by total sales of each rate class. This per-kWh rate is reduced by a variable operations and maintenance component the utility has derived from a marginal cost of service study. Each class-specific rate is then applied to a program savings forecast for each class.

Lost revenues continue to be collected for pancaked savings effects until the company comes in for a rate case and resets the billing determination. Companies are mandated to file a rate case with the commission at least every three years. There is also a requirement that lost revenues cannot cause a utility to earn more than its authorized rate of return. The result in Nevada has been the return of lost revenues—in part or in whole—to customers in 2013 and 2014. Details of policy results, including energy savings and lost revenue dollars recovered, are reported in the following section.

Outcomes

Nevada's lost revenue adjustment mechanism is complex and requires significant time and effort from both utility and commission staff. While utilities have expressed that the lost revenue adjustment mechanism is necessary for them to become whole after investing in energy efficiency, the arduous regulatory requirements of the LRAM have led the PUCN to open an investigatory docket looking at other ways for Nevada electric utilities to recover lost revenues. Concerns regarding whether utilities are over-earning as a result of the LRAM have led to recent settlements and the return of LRAM monies to customers. Meanwhile, statewide electricity savings have declined since 2010.

ENERGY SAVINGS

While utilities in Nevada continue to invest in cost-effective energy efficiency, it is unclear whether the LRAM is a sufficient policy lever to encourage them to ramp up investments. Overall incremental electricity savings in Nevada, while still higher than the national average, have dropped in recent years.[19] Since avoiding rate hikes was a key concern for all parties in Nevada, some programs may actually have been scaled back as a result of the LRAM. There was some concern over the optics of customer funds being used to recover large amounts of lost revenues, and efficiency portfolios were scaled down somewhat from electric utilities' initial proposals. Annual incremental energy savings are shown in figure B1.

[19] In 2010, statewide electricity savings were second highest in the country, totaling about 1.28% of retail sales. In 2013, Nevada ranked 21st, with total incremental electricity savings of 0.81%. (See the State Energy Efficiency Scorecard for more details). Note also that since 2010, the PUCN has determined that CFL measures no longer count toward savings claimed by utilities.

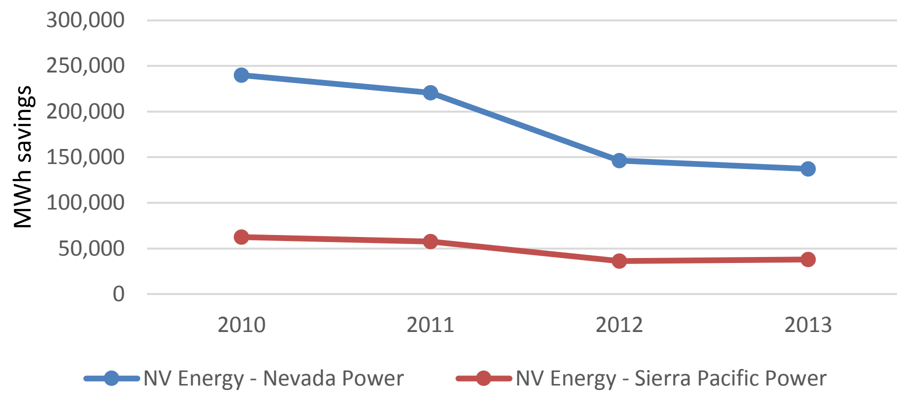

Figure B1. Net incremental savings (MWh) in 2010–2013 for Nevada energy companies. *Sources:* Utility annual reports.

FINANCIAL OUTCOMES

The most recent estimates of lost revenue recovery from efficiency programs are presented in table B1. The legislation and the PUCN rules that followed are clear that utilities are eligible to recover the full retail rate for energy savings achieved. However there were concerns that the companies were over-earning in recent years as a result of the LRAM. The state's consumer counsel asked the commission to open a proceeding to determine if the utilities were eligible for lost revenues in a year in which they achieve their authorized rate of return. Subsequently, the commission adopted a follow-up rule requiring the companies to return funds to ratepayers in the event of over-earning. The companies were required to refund to customers the lost revenue amounts collected for 2012. As a condition of a merger approved by the PUCN, the companies agreed to forgo lost revenues in 2013 and half of lost revenues in 2014. In 2015, the utility is slated to collect and retain lost revenues as normal.

Table B1. Lost revenue recovered in recent years

Utility	Lost revenue dollars eligible for recovery[1]	Cost of energy efficiency programs	Total annual energy savings achieved (kWh)[2]	Eligible LRAM recovery per energy unit saved[3]
		2013		
Nevada Power Company	$14,692,023 (returned to customer base)	$34,376,982	358,021,585	$0.04
Sierra Pacific Power Company	$5,566,833 (returned to customer base)	$5,017,084	110,812,881	$0.05
		2014		
Nevada Power Company	$19,546,227 (portion returned to customer base)	$50,300,000[4]	484,415,682	$0.04
Sierra Pacific Power Company	$2,484,850 (portion returned to customer base)	$10,410,000[4]	60,797,089	$0.04

[1] Estimates of dollars recovered or budgets. [2] Energy savings figures do not match those shown in figure B1 since lost revenues are calculated based on annual, not incremental, energy savings. [3] Estimate of what utility would have recovered if dollars were not returned to customers. [4] Estimate of energy savings.

Discussion

Nevada now has several years of experience implementing a lost revenue adjustment mechanism. However the LRAM remains contentious. Parties identified evaluation procedures and the timing of rate cases and demand-side management cases as pieces of the regulatory structure that need improvement. Evolving utility portfolios that include next-generation program offerings have also raised questions about the type of programs eligible for lost revenue recovery.

EVALUATION, MEASUREMENT, AND VERIFICATION

Nevada's LRAM has had a significant effect on the time and money spent on evaluation procedures for efficiency programs and has led to some level of controversy and conflict among parties. Utilities have more than doubled their expenditures on EM&V, and the public utilities commission has likewise increased its staff to accommodate the additional workload. Getting the energy savings values correct is important to avoid over- or under-recovery of lost revenues by utilities (and the potential overpayment by ratepayers), but parties in Nevada are at odds as to the proper level of time and resources to devote to EM&V. Key elements of EM&V, including inputs and general methodology, have also been adjusted over time. This has led to confusion and the impression of subjectivity in calculations in some cases.

EVOLVING PROGRAM OFFERINGS

As utility portfolios mature, it is natural to move toward more cutting-edge program offerings. Utilities in Nevada have recently begun offering home energy reports and programs aimed at changing consumer behavior. While energy savings from these types of programs and the necessary EM&V processes have been demonstrated and accepted in states across the country, some parties in Nevada have questioned the amount of allowable revenue recovery for these program types.

PROCESS ISSUES

The timing and process of truing up lost revenues have been complex. Two proceedings occur each year: one focused on demand-side management portfolios, the other focused on lost sales and rates. Currently, the PUCN will continue to adjust and true up lost revenue dollars for a single program year over the course of three or more years. Parties have expressed the need to better synchronize efficiency program years and rate years.

Looking Forward

The PUCN opened an investigatory docket in 2014 to take a closer look at the state's lost revenue adjustment mechanism. All parties have expressed that the current LRAM is overly complex and that there is significant room for improvement. In 2015, the PUCN issued a notice of its intent to act upon a new mechanism (Docket 14-10018). The mechanism would provide a rate of return on the program costs for DSM programs. Some parties have expressed that they believe the PUCN has the authority and latitude to implement a decoupling policy without going back to the legislature, but many others have questioned whether the commission has such latitude under existing authority.

OKLAHOMA

History

Energy efficiency programs are required by Oklahoma Administrative Code, although specific efficiency portfolios and their associated energy savings are determined largely by investor-owned utilities (IOUs). Under OAC 165:35:41, all electric utilities regulated by the Oklahoma Corporation Commission (OCC) must propose and implement energy efficiency and demand response programs within their service territories, with new proposals issued at least every three years. Energy efficiency programs were initiated throughout the state in 2008, after the OCC launched a stakeholder collaborative to explore potential structures for demand response programs within the state.

From the beginning, stakeholders recognized the need to motivate utilities to implement efficiency. With stakeholder input, the OCC laid out a loose set of efficiency rules and encouraged utilities to come forward with their own proposals for incentivizing investments in energy efficiency. Utilities presented the commission with a three-legged stool: in addition to cost recovery, they proposed a shared savings mechanism and a lost revenue adjustment mechanism.

Other Relevant Regulatory Features

Oklahoma does not have an energy efficiency resource standard in place or specific energy savings targets, but utility efficiency investments are influenced largely by a shared savings incentive put in place during the same time as the LRAM. There are no performance thresholds for receipt of the shared savings incentive. Specifics of the performance incentive are detailed in Nowak et al. (2015). Currently, there is an open docket examining the structure of the performance incentive, with a proposal to cap the potential return.

LRAM Policy Details

Oklahoma's LRAM was first approved as part of a settlement in PUD Cause No. 200700449, Order No. 555302. The policy applies to both investor-owned electric utilities in Oklahoma: Public Service Company of Oklahoma (PSO) and Oklahoma Gas and Electric Company

(OG&E). Gas utilities have performance-based rates, and LRAM rules do not apply. Lost margins are calculated by multiplying energy savings resulting from demand response programs by an embedded cost factor determined in the most recent rate case. Savings are reported by utilities to the OCC, and while third parties have been used to verify energy savings, utilities are also given the option to self-verify. Lost revenues are recovered annually, with no ceiling specified. However lost revenues are zeroed out as part of each rate case.

Outcomes

Energy efficiency has received greater attention in Oklahoma in recent years, driven by OCC rulemakings and support from Governor Mary Fallin. The LRAM is an important tool in encouraging utilities to invest in efficiency, especially when coupled with the shared savings incentive. Over several years of implementation, the need for clear requirements and process transparency has become evident. Furthermore, although energy savings have ramped up, IOUs have yet to achieve the energy savings currently being realized in other states across the country.

ENERGY SAVINGS

Oklahoma has seen an uptick in energy savings in recent years. Statewide, net electricity savings grew from 0.04% of sales in 2009 to 0.27% of sales in 2013 (Sciortino et al. 2011; Gilleo et al. 2014). This has been driven largely by increased investment in efficiency by the state's investor-owned utilities. Because Oklahoma began implementing performance incentives and LRAM at around the same time, it is difficult to determine which of the two has had a greater influence on utility behavior. However stakeholders in the state firmly believe growth in efficiency is driven by the entirety of the three-legged stool of cost recovery, incentives, and LRAM, and that no one policy lever could drive efficiency without support from the others. Annual incremental energy savings for the two IOUs are shown in figure B2.

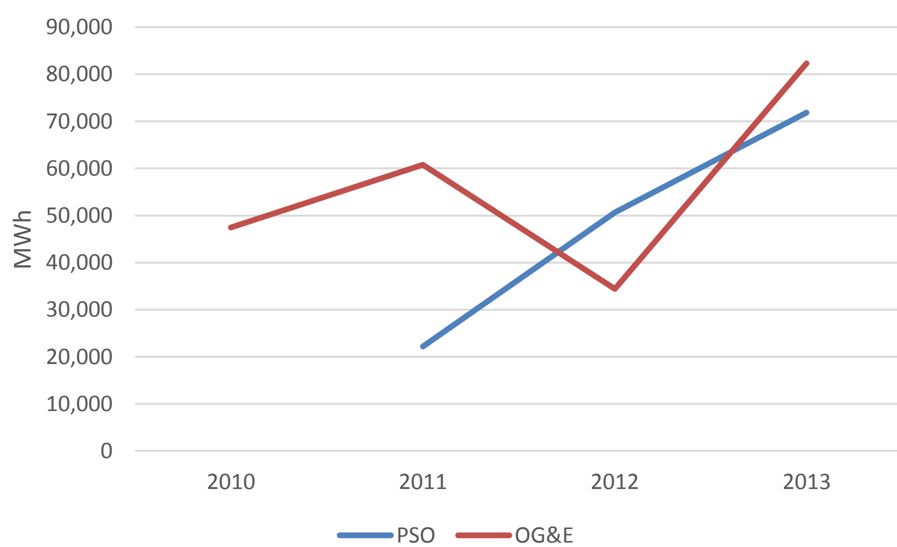

Figure B2. Net incremental savings (MWh) in 2010–2013 for Oklahoma electric IOUs. 2010 energy savings were not available for PSO. *Sources:* Utility annual reports and OK OCC data.

Figure B2 also characterizes energy savings patterns as a result of the three-year planning process. The drop in OG&E savings in 2012 is likely due to its overachievement of savings in earlier years, reducing pressure to generate savings during the third year of the program cycle. In 2013, OG&E achieved significant (and likely unexpected) energy savings as a result of its SmartHours program, which was originally targeted at reducing peak demand.

While savings have grown noticeably in the state since 2009, the question of whether efficiency is being encouraged *sufficiently* still exists. IOUs have ramped up programs in response to the policy levers in place in the state, but Oklahoma statewide electricity savings were well below the national average of 0.56% of retail sales in 2013 (Gilleo et al. 2014). Stakeholders were unsure whether energy savings would continue to climb solely on the basis of the existing policy environment in Oklahoma.

FINANCIAL OUTCOMES

The most recent estimates of lost revenue earnings from efficiency programs are presented in table B2.

Table B2. Lost revenue recovered in recent years

Year	Lost revenue dollars recovered*	Cost of energy efficiency programs	Total energy savings achieved*	LRAM earnings per energy unit saved
		OG&E		
2011	$3,105,699	$18,200,806	60,743,474	0.05
2012	$3,342,530	$14,662,068	34,405,983	0.10
		PSO		
2012	$4,348,385	$21,963,690	50,632,000	$0.09
2013	$6,301,020	$22,335,179	71,880,000	$0.09

* OG&E 2013 recovery request was still under review at the time of research, so 2013 LRAM numbers were not available.

Discussion

After several years of LRAM in Oklahoma, stakeholders point to a number of areas where lessons have been learned. Stakeholders have been proactive in applying several of these lessons, making tweaks to the existing rules. Many of these adjustments address methods of smoothing the regulatory process. However those aimed at encouraging IOUs to achieve higher levels of electricity savings have faced significant opposition from several parties.

CONSISTENT AND CLEAR EXPECTATIONS

Oklahoma stakeholders emphasized the importance of clear definitions and standards that apply to all utilities affected by an LRAM. For instance, though stakeholders were under the impression that OCC rules intended that LRAM apply to net savings, original rules did not specify whether utilities should report lost revenues calculated from net or gross energy savings. As a result, one IOU reported net energy savings while another reported gross energy savings. In 2014, the utilities commission approved new demand rules for future portfolio filings that specifically require the use of net savings for calculation of lost revenues. IOUs also differed in their calculations of embedded costs. Stakeholders felt that more clearly defining requirements and expectations during the rule design process might have been simpler than making changes after the fact and might have led to the sense of a more even playing field.

EVALUATION, MEASUREMENT, AND VERIFICATION

Recently, auditing of efficiency program evaluations has received greater attention from OCC staff. In prior years, utilities self-verified energy savings numbers. However IOUs are now required to hire independent contractors to evaluate programs and verify energy savings. Some stakeholders in the state noted that even this requirement may not lead to truly independent verification of savings. Utilities have also been tasked with diving more deeply into their assessment of net savings, accounting for free-ridership and the overlap between programs. The OCC has bulked up its efficiency-focused staff to handle increased back-and-forth with utilities related to demand response program filings.

TRANSPARENCY

Though utilities and the OCC have worked to create consistency in reporting systems, other stakeholders have expressed frustration that many filings are not publicly available. To date, utility EM&V reports have not included numbers for lost revenues, making it difficult for outside parties to track processes and leading to surprises when utility lost revenue filings are significantly higher than predicted. New rules require that EM&V filings include data on lost revenues and performance incentives, which should help ease these tensions in the future.

Looking Forward

The OCC recently approved new rules that apply to both electric and gas companies in future efficiency portfolio filings.[20] These rules do not largely change the structure of the LRAM within the state, but they do clarify definitions and methodologies. Important changes have also been made to the performance incentive in the state. In addition, efficiency advocates have proposed mandatory energy savings targets in recent years. While these targets were incorporated into a draft OCC rulemaking, they were later dropped. Stakeholders have indicated it is unlikely that Oklahoma will consider energy savings targets in the near future.

INDIANA

History

Back in 1983, Indiana was actually one of the first states to enact a Certificate of Convenience and Public Necessity statute, which required utilities to demonstrate need before constructing or purchasing new generation facilities. In 1995, Indiana adopted an Integrated Resource Planning (IRP) rule (170 IAC 4-7), requiring electric utilities to develop an IRP that evaluated demand-side and supply-side resources on a comparable basis.

In spite of that framework, the fact that Indiana utilities were achieving very little energy efficiency savings led to a series of hearings and investigations by the Indiana Utility

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[20] See OAC 165:45-23 (Gas Demand Rules) and OAC 165:35:41 (Electric Demand Rules).

Regulatory Commission (IURC) beginning in 2004, culminating in a landmark order in 2009 (Cause 42693, December 9, 2009). The order established a two-part approach: Utilities were required to contract with a single, independent, third-party administrator for a basic set of statewide "Core" programs, and also to individually administer additional energy efficiency programs ("Core Plus") in their own service territories to address aspects not covered by the Core initiatives. The order also established an energy efficiency resource standard (EERS), requiring utilities to meet annual savings goals. The goals began at 0.3% of annual sales in 2010, increasing to 1.1% in 2014 and leveling off at 2.0% in 2019.

With regard to lost revenues, Indiana had actually established an administrative rule for lost revenue recovery in 1995 (170 IAC 4-8-6) as part of its guidelines for demand-side management cost recovery. However, as noted above, very little DSM was taking place. Now, subsequent to the 2009 order, four of the five major electric utilities (Indiana Michigan Power [I&M], Northern Indiana Public Service Company [NIPSCO], Vectren Indiana, and Duke Energy Indiana) have approved mechanisms. Indianapolis Power and Light (IPL) sought commission approval of a mechanism but was denied (Cause No. 43523), in part because of the long period of time since its last rate case and the resulting uncertainty of the lost margin calculation based on those dated rates. (IPL subsequently filed an updated request, Cause No. 44497.)

In March 2014 the Indiana legislature voted (SB 340) to end many of the aspects of the IURC 2009 order, effectively eliminating both the Core program requirement and the annual savings goals that order had established. Governor Mike Pence neither signed nor vetoed the bill, and it became law in April 2014. While the legislation did not alter the state's lost revenue policy, the entire framework for utility energy efficiency programs in Indiana is somewhat uncertain at this point.

LRAM Policy Details

The utilities all follow the Indiana general administrative guidelines (170 IAC 4-8-6), with the details on each mechanism spelled out in each individual utility case filing (e.g., Duke: Cause No. 43955; Vectren: Cause Nos. 43938 and 43405; I&M Cause No. 43827). These case filings also represent their initial three-year plans following the issuance of the 2009 landmark order. The utilities must provide evaluation data on the energy savings impacts of their programs (Core and Core Plus), net of free riders, and those amounts are used to calculate the total lost revenues. Lost revenues are recovered annually for Duke, I&M, and Vectren, and semiannually for NIPSCO. Under current policy, lost revenues are recovered for the life of the measure or until the company's next rate case, whichever comes first, and there is no limit or ceiling on lost revenue recovery.

Other Relevant Regulatory Features

Four of the investor-owned electric companies in Indiana are eligible to earn performance incentives for achieving energy savings goals. Of the four, Indiana Michigan Power and IPL have a shared savings performance incentive. The other two operate under a tiered incentive approach, receiving a greater performance incentive as performance increases. There are no electric companies in Indiana with decoupled rates. However, of the three largest natural gas distribution companies operating in the states, two have decoupled rates for most rate classes. Finally, Indiana offers companies the opportunity to participate in a voluntary renewable portfolio standard to earn a higher return on equity for rate-base facilities. Energy efficiency savings are one means by which a company can meet the voluntary standard. However no company has formally requested commission approval to participate in the standard.

Outcomes

ENERGY SAVINGS

Statewide energy savings increased dramatically in Indiana subsequent to the 2009 order. In 2012, utilities achieved electricity savings of 0.59% of retail sales, about the national average. Statewide energy savings are shown in figure B3.

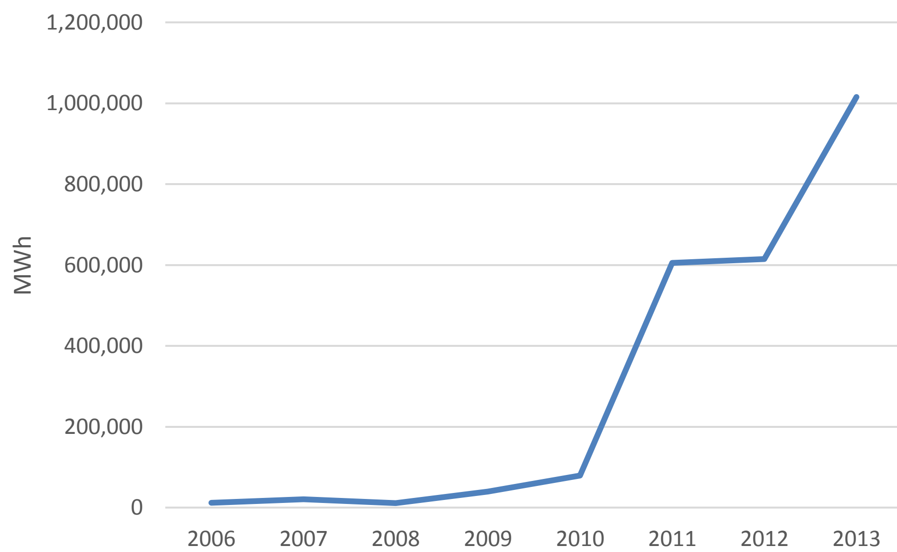

Figure B3. Indiana energy savings (MWh), 2006–2013. *Source*: ACEEE *State Energy Efficiency Scorecard* 2007–2014.

FINANCIAL OUTCOMES

Table B3 shows the dollars recovered under the LRAM for three IOUs in Indiana.

Table B3. Indiana lost margin recovery and savings 2012–2013

Company	LRAM recovered	Program cost	Total annual energy savings (MWh)
2013			
Duke Energy	$3,669,344	$36,587,777	267,711
Vectren	$6,014,360	$11,251,668	63,072
Indiana Michigan Power	$9,115,961	$22,335,442	121,472
2012			
Duke Energy	$2,521,055	$22,905,994	215,795
Vectren	$3,765,798	$11,068,667	64,864
Indiana Michigan Power	$3,819,984	$11,436,775	60,460

Amounts subject to reconciliation process where estimated lost revenues, program costs, and savings are trued up with actual lost revenues program costs and savings based on program evaluation results. *Sources:* Indiana Utility Regulatory Commission Case Filings: Duke (Cause No. 43955 DSM-2); Vectren (Cause No. 43405 DSM-10 and DSM-11); Indiana Michigan Power (Cause No. 43827 DSM -3).

Discussion

Indiana utilities have clearly significantly ramped up their energy efficiency spending and savings since the 2009 IURC order. It is unclear what role the LRAM policy has played in that, since the utilities have had that LRAM policy available since 1995.

Lost revenue recovery has emerged as a somewhat contentious issue in Indiana, with advocates expressing concern about the potential for adding considerable costs to ratepayers. Although Indiana has only a couple of years' experience with large-scale energy efficiency programs, one can see from the table that the LRAM costs are already substantial. The open-ended potential for pancaking of lost revenue costs over multiple years is of particular concern, given that there is no cap or time limit on the recovery of lost revenues. Documents filed by several utilities in recent cases indicate that if lost revenues are collected for the life of the measures, total lost revenue costs would exceed the total program costs.

True symmetrical decoupling is an alternative that avoids many of the problems of LRAM, and some advocates are considering recommending that alternative. At one time Vectren sought a decoupling mechanism for its gas and electric utilities. However decoupling was rejected for electric utilities in a 2011 IURC order (Cause No. 43839).

EVALUATION

The Core programs were evaluated by an independent third party, selected by the DSM Coordinating Committee established by the IURC (comprising the utilities and the Office of the Utility Consumer Counselor [OUCC] and involving other key stakeholders). For the Core Plus programs, each utility is responsible for hiring a third party to evaluate its own programs. However the utilities generally have oversight committees for the Core programs with members including the OUCC and often other stakeholders. These committees often participate in decisions regarding the selection of a third-party evaluator; they also review the evaluator's reports and analyses. Energy savings are defined as being net of free riders. The results of these evaluations are used both in determining lost revenues and in calculating performance incentives for the utilities.

PROCESS

The process for tracking and awarding lost revenues is already proving to be fairly complicated. IURC staff noted that timely EM&V is particularly important to accomplish for the full portfolio of programs. If EM&V data are submitted for only some programs because the EM&V process for other programs is not complete, it results in challenges in tracking and reconciling subsequent evaluations. Also, it is important that all utilities use consistent definitions related to reported, actual, and verified savings. Although it is still early in the experience with LRAM, stakeholders acknowledge that tracking lost revenues over multiple years raises concerns about keeping track of pancaked lost revenues. They further say that trying to adjust those amounts as energy efficiency measures reach the end of their estimated lifetimes would be extremely challenging.

Looking Forward

The policy landscape for utility energy efficiency in Indiana is fairly uncertain at this point. In his letter to the legislature after the enactment of SB 340, the governor stated, "I have requested the Indiana Utility Regulatory Commission to immediately begin to develop recommendations that can inform a new legislative framework for consideration during the 2015 session of the Indiana General Assembly." This suggests that the entire framework for utility energy efficiency programs in Indiana is up for revision. It is yet to be determined whether there will be any type of utility energy efficiency requirements at all (much less annual savings targets), and what associated policies (e.g., LRAM, decoupling, shareholder incentives) will remain or will be put in place.

At this point the Indiana utilities have all filed, and had approved, one-year plans to continue some energy efficiency programs during 2015. It is noteworthy that now that the IURC annual savings targets have been struck down by SB 340, the projected savings from the voluntary utility plans are, in aggregate, about half of what would have been required under the previous IURC standard.

SOUTH DAKOTA

History

South Dakota is unusual in that energy efficiency programs are not a legislative or regulatory requirement. In the mid-2000s, the South Dakota Public Utilities Commission (PUC) tasked staff with investigating options to encourage the state's six investor-owned utilities to offer energy efficiency programs. Initially, staff suggested a standard program design. However five of South Dakota's six IOUs operate in other states, many with established efficiency programs. They were opposed to the standard program design, noting it would be simpler to offer portfolios that mirrored their existing efficiency programs in other states.

The commission asked utilities to bring other options for efficiency programs to the table. Several utilities approached the PUC with the idea of performance incentives and lost revenue adjustment mechanisms. The commission originally approved performance incentives but moved away from that approach in 2010. Working in collaboration with utilities, the commission authorized an LRAM that applied to all IOUs. Unlike other states, the LRAM does not take energy savings into account.

Other Relevant Regulatory Features

South Dakota does not require utilities to offer energy efficiency programs.[21] The PUC authorized performance incentives in the past, but none is currently in place or pending. Most utilities in the state are interconnected and deliver the majority of their loads out of state; due to South Dakota's small population, they tend not to consider the South Dakota portion of their load in supply-side decisions. Many of the efficiency programs throughout the state began as extensions of existing, more robust programs in other, neighboring states.

LRAM Policy Details

South Dakota's LRAM was first authorized for Montana-Dakota Utilities in 2010.[22] The LRAM applies to all investor-owned utilities for both electricity and natural gas. Lost revenues are not based on verified energy savings. Instead, they are negotiated as a percentage of approved budget spending. Utilities estimate savings to determine the cost effectiveness of efficiency programs but are not required to submit savings details to the commission as part of LRAM proceedings. Lost revenues are recovered contemporaneously through a rider and trued up over time. Recovery is limited to the year in which expenses are incurred.

Outcomes

The South Dakota PUC is prohibited from requiring utilities to implement efficiency programs, and therefore the LRAM is the primary method by which the PUC has sought to encourage efficiency programs throughout the state. Efficiency offerings are influenced by South Dakota's demographic and geographic characteristics. The small population relative to the number of utilities, and the fact that nearly all of the state's utilities are interconnected, mean that utility experience in neighboring states is largely what drives efficiency in South Dakota. Since programs are small, the costs of evaluation are disproportionately high to utilities. Furthermore, all parties have agreed that simplicity is a practical strategy to maximize the efficiency of the programs. As a result, little emphasis is placed on verification of actual energy savings.

ENERGY SAVINGS

PUC staff have been successful in working with IOUs to initiate some level of energy efficiency programming in South Dakota. Efficiency budgets have slowly but steadily increased in recent years. Figure B4 illustrates relatively consistent savings levels. South Dakota's statewide savings remain well below the national average of 0.56% savings as a percentage of retail sales.

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[21] In 2009, the PUC did adopt a modified Public Utilities Regulatory Policies Act (PURPA) standard requiring IOUs "to integrate cost-effective energy efficiency resources into [their] plans and planning processes," but there is no rule or law requiring specific energy efficiency programs or savings levels.

[22] See docket NG09-001 (http://puc.sd.gov/Dockets/NaturalGas/2009/ng09-001.aspx).

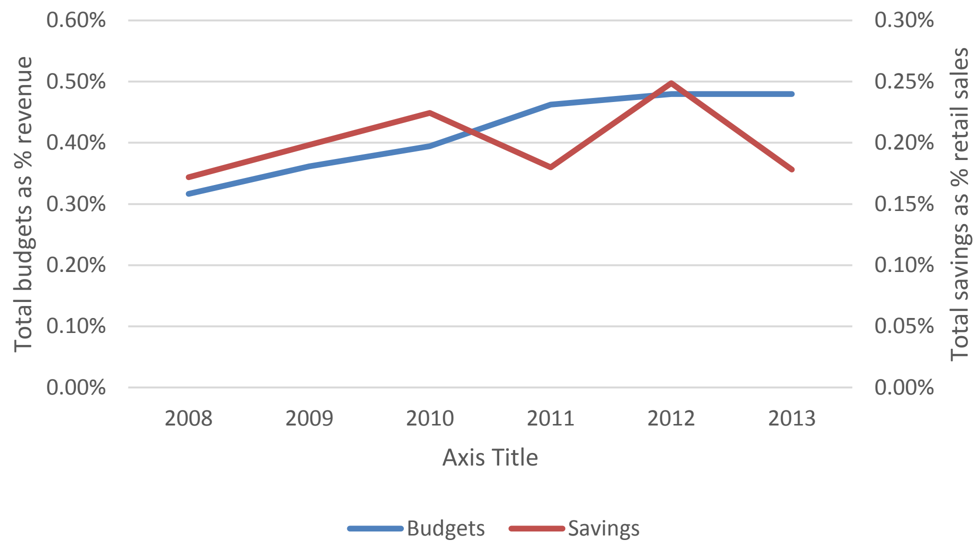

Figure B4. Total statewide spending and savings on energy efficiency, 2008-2013. *Source:* ACEEE *State Energy Efficiency Scorecard*, 2008–2014.

FINANCIAL OUTCOMES

South Dakota's LRAM is a function of utility budgets for energy efficiency rather than energy savings achieved. Dollars recovered, program budgets, and non-verified estimates of energy savings are shown in table B4. Recovery is based on budgets rather than actual spending, so any overspending by utilities does not result in greater allowable lost margin recovery. Similarly, while programs must be cost effective, the commission places little emphasis on verification of energy savings.

Table B4. Sample of lost revenue recovered in recent years

Utility	Lost revenue dollars recovered*	Cost of energy efficiency programs	Total energy savings achieved*	LRAM earnings per energy unit saved
		2013		
Otter Tail Power	$84,000	$281,548	1,611,525	$0.05
Montana-Dakota Utilities	$14,264	$168,026	46,130	$0.31
		2012		
Otter Tail Power	$84,000	$309,911	3,910,104	$0.02
Montana-Dakota Utilities	$6,056	$51,554	30,840	$0.20

*Estimates

Table B4 also shows the small size of programs in South Dakota. Each utility serves a relatively small customer base, and opportunities to work with industrial customers are limited. The small size of efficiency programs is one of the main reasons little emphasis has been placed on actual energy savings to date. Parties noted that lost margin recovery to date has been relatively minimal, and there has not been much scrutiny by external stakeholders.

Discussion

The driving force behind South Dakota's LRAM has been an emphasis on simplicity. To date, this seems to have worked for the state. Customer bases are limited, programs are small, and outside stakeholders pay little attention to regulatory features like lost margin recovery. However, in exchange for simplicity, the state has made a significant tradeoff: verification of energy savings.

SMALL SERVICE TERRITORIES AND NEIGHBOR STATE INFLUENCE

Programs in South Dakota are shaped largely by neighboring states. Utilities also provide service to Iowa, Illinois, Minnesota, and Montana, all of which have relatively robust energy efficiency programs that predate those in South Dakota. These experiences were shifted over the border to shape portfolios in South Dakota. However modifications were made to account for the small population of the state. For example, because the industrial base is small, programs targeted at this sector are limited.

EVALUATION, MEASUREMENT, AND VERIFICATION

Unlike many other states, there is little back-and-forth between the commission and utilities regarding verification of savings. There is evaluation of savings at some level—utilities must, for example, estimate savings in order to determine whether programs are cost effective. However no evaluation of savings is required by the commission. Parties indicated that even if savings estimates are off by an order of magnitude, programs would still be cost effective within the state. There has been very little public scrutiny of the budget-based LRAM methodology, likely due to the small size of efficiency programs.

Looking Forward

Though both utilities and commission staff say they recognize the importance of efficiency, there is no clear sign that efficiency will continue to gain traction in the state under the current regulatory structure. However all parties note that potential federal regulations, like the Clean Power Plan, could be a possible turning point. Federal regulations could not only require the ramp-up of programs but also necessitate more careful calculations of energy savings. These potential changes seem to have already influenced utility behavior to some extent, with utilities indicating that they have paid more attention to internal savings verification recently.

ARKANSAS

History

Investor-owned utilities in Arkansas had very little involvement in providing customer energy efficiency programs until 2007, when the Arkansas Public Service Commission (APSC) approved Rules for Conservation and Energy Efficiency Programs requiring electric and gas utilities to propose and administer energy efficiency programs (Docket No. 06-004-R, Orders No. 1, 12, 18). The state's jurisdictional IOUs filed Energy Efficiency Plans in July 2007 containing proposed Quick Start efficiency programs. The utility response was relatively small, with the utilities expressing concern about adverse financial impacts. In response, in 2010 the commission took several actions to increase the energy efficiency efforts.

Also in December 2010, the APSC adopted an energy efficiency resource standard (EERS) for both electricity and natural gas, guidelines for efficiency program cost recovery, and a shareholder performance incentive. The EERS targets set by the commission were moderate, calling for an annual reduction of 0.25% of total electric kWh sales in 2011, 0.5% in 2012, and 0.75% in 2013. In 2013 the APSC extended the 0.75% target to 2014 and set a target of 0.9% for 2015. It deferred a ruling on 2016–2017 targets pending completion of a thorough potential study aimed at improving programs.

In December 2010 the Arkansas PSC approved a joint electric and gas utility motion to allow the awarding of lost contributions to fixed costs that result from future utility energy efficiency programs. All investor-owned utilities are approved to recover lost revenues as part of the annual energy efficiency program tariff docket (see Order No. 14 Docket 08-137-U). In 2007 the APSC approved a decoupling mechanism for the three major natural gas distribution companies in the state, but no decoupling has been approved for electric utilities.

In December 2010 the APSC began a process by which it would approve incentives to reward achievement in the delivery of essential energy conservation services by investor-owned utilities (see Order No. 15 Docket 08-137-U). Such incentives were approved for all three gas utilities in the state and the two largest electric utilities in 2012 and 2013.

LRAM Policy Details

The APSC established its LRAM policy in 2010 (Docket No. 08-137-U, Order No. 14, December 10, 2010). All investor-owned electric and gas utilities are eligible under the policy to apply to receive lost contributions to fixed costs (LCFC). There are no minimum energy savings thresholds or other achievements required to qualify for receiving lost revenues.

The LCFC is calculated as the base rate (i.e., the total rate minus variable costs [typically just fuel costs]) times the net savings from the energy efficiency programs. Lost revenues are calculated and recovered annually. The utility is eligible to receive lost revenues for the life of the measure, and there is no limit or ceiling on the amount of lost revenues that can be recovered, except that the LCFC resets to zero at each new rate case.

Other Relevant Regulatory Features

Arkansas has had an EERS in place since 2010 for both gas and electric utilities. The energy savings targets are established by the APSC in three-year cycles. The three natural gas distribution companies in Arkansas are decoupled and eligible to earn performance incentives for efficiency program results. There are no decoupled electric companies in Arkansas but the four electric IOUs do have LRAMs in operation and are able to earn performance incentives.

Outcomes

ENERGY SAVINGS

Statewide electricity savings are shown in figure B5. Energy savings in Arkansas are driven largely by the state's EERS requirements. A 2014 study found that, on the whole, Arkansas met or came close to meeting savings targets in 2011 and 2012 (Downs and Cui 2014). The extent of the LCFC's role in the utilities' commitment to meeting these targets is unclear, particularly since there is no minimum threshold for receiving lost margin.

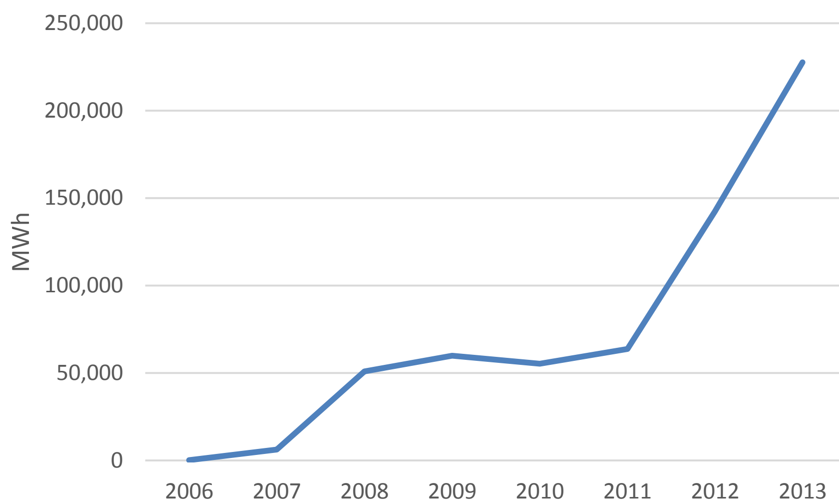

Figure B5. Arkansas energy efficiency program savings 2006–2013. *Source:* ACEEE *State Energy Efficiency Scorecard* 2007–2014.

FINANCIAL OUTCOMES

Dollars recovered through the LCFC are shown in table B5. As savings targets rise, program budgets have ramped up significantly. Resulting lost revenue dollars have also increased in recent years.

Table B5. Arkansas electric utility lost revenue and savings 2012–2013

Company	LRAM recovered	Program cost	Total annual energy savings (MWh)
2013			
Entergy Arkansas	$10,534,980	$52,285,262	188.468
SWEPCo	$1,015,859	$6,803,249	25,387
2012			
Entergy Arkansas	$3,665,223	$28,515,019	107,627
SWEPCo	$545,377	$5,289,095	17,767

Source: Arkansas Public Service Commission

Discussion

The major electric utilities in Arkansas have definitely increased their energy efficiency efforts and achievements in response to the various commission orders and policies that have been in place since 2007. How much of that might be attributable to the LRAM policy is difficult to say, but staff did indicate that doing something about the lost revenue from energy efficiency was an important factor for the IOUs.

The APSC established its LRAM policy in 2010 in response to a joint motion by the major investor-owned utilities. At the time, the commission stated:

> While decoupling may eventually prove to be a better way to tame the "throughput incentive," the Commission at this time accepts the EE Utilities' argument that an LCFC mechanism is more appropriate for electric utilities, which expect growth in sales . . . . The Commission commits to approval of LCFC recovery only in the context of significant goal setting and the development of robust EM&V, as detailed in other orders issued contemporaneously with this Order. Thus, recovery of revenues lost is not an independent right of utilities, but rather a component of a coordinated group of policies reasonably calculated to deliver overall benefits to ratepayers, to utilities, and to society in a cost-effective manner. (Docket No. 08-137-U, Order No. 14, p.17-18)

The commission clearly had some reservations about allowing LRAM in the first place, and it certainly left open the possibility of revising the policy in the future. And APSC staff expressed concerns about the asymmetrical nature of LRAM (i.e., utilities collect for sales lost to energy efficiency but have no obligation to refund excess revenues if sales exceed forecasts) and the potential for LRAM costs to mount over time due to pancaking.

A more recent commission order, in 2013, sought to encourage utilities to file decoupling proposals:

> In the expectation that further rate cases will be filed by electric utilities in 2013 and 2014, the Commission issues this order to encourage proposals by electric utilities …that would decouple revenues from sales volumes. (Docket No. 08-137-U, Order No. 19, p.1)

And the commission specifically asked for "proposals that include the following features":

- Customer charges that are set at a level low enough to encourage conservation[23]
- Establishment of separate revenue-per-customer amounts for—at a minimum—residential, small commercial, and demand-metered commercial customers

[23] Fixed charges are the portion of the customer's utility bill not tied to consumption. It is noteworthy that the commission appears here to be taking a preemptive stance against proposals for high fixed charges, or "straight fixed-variable" rate design (which are sometimes requested by utilities as mechanisms to counter the problem of lost revenues from energy efficiency programs and/or customer-sited solar photovoltaic installations).

- Establishment of a true-up mechanism that credits to or collects from customers any over- or under-recovery of revenue, respectively

EVALUATION

The evaluation process is overseen by the APSC. The commission requires each utility to hire its own independent EM&V contractor to perform evaluations. It further requires the utilities to jointly fund an independent EM&V monitor who provides oversight and guidance and operates under the direction of the commission staff. The commission established an EM&V collaborative (Parties Working Collaboratively, or PWC) to develop a technical resource manual that is updated annually and approved by the commission. Arkansas uses net savings as its evaluation metric.

Looking Forward

As noted above, the commission has expressed interest in receiving proposals from the electric utilities for true symmetrical decoupling, to replace the existing LRAM mechanisms. Thus far, one of the two largest utilities in 2014 did indicate it would file a decoupling proposal in a future rate case. However it should be noted that there will be substantial turnover among commissioners for 2015, so there is the potential for a sea change in the amount of support for efficiency coming from the APSC.

MISSOURI

History

Major legislation enacted in 2009 marked a major turning point for utility energy efficiency programs in Missouri. The Missouri Energy Efficiency Investment Act (MEEIA, SB 376) established a regulatory framework for utility energy efficiency programs to consider demand-side investments in the same framework as traditional investments in supply and delivery infrastructure. The corresponding Public Service Commission (MPSC) rules for implementing the legislation became effective in May 2011. Prior to passage of MEEIA, Missouri had limited energy efficiency programs for utility customers even though electric utilities were required to file and implement integrated resource plans.

Key provisions of MEEIA specifically address the utility business model. Under MEEIA the Public Service Commission is to

- Provide timely cost recovery for utilities
- Ensure that utility financial incentives are aligned with helping customers use energy more efficiently
- Provide timely earnings opportunities associated with cost-effective, measurable, and verifiable efficiency savings

MEEIA opened the door for electric utilities to propose and establish demand-side investment mechanisms (DSIMs) for energy efficiency programs. Addressing the utility business model was critical for Missouri's utilities to move ahead with such programs. One of Missouri's utilities, in fact, had established a fairly large portfolio of programs at the time MEEIA was enacted. Ameren Missouri had launched a portfolio of customer programs totaling about $70 million over a three-year period (2009–2011). However the company rolled back this level of program spending and associated activity when cost recovery and incentive mechanisms were not approved during Ameren Missouri's 2011 rate case. When the commission approved an agreement between the utility and parties to its MEEIA application that established DSIMs, the impact was significant. Ameren soon launched a full portfolio of energy efficiency programs totaling $145 million over the three-year program period.

The story is similar for Kansas City Power & Light (KCP&L), which had limited energy efficiency programs and associated investment in place prior to establishing its own version of a DSIM late in 2014. Once this mechanism was in place, KCP&L initiated a portfolio of energy efficiency programs totaling $28.6 million over 18 months, after which time the company is expected to file a full three-year plan. KCP&L Greater Missouri Operations (GMO), a utility operating company owned by the same corporation as KCP&L, serves an area surrounding Kansas City. GMO had in place a small set of programs prior to establishing a DSIM. With cost recovery in place, the company is proceeding with a greatly expanded set of programs.

Other Relevant Regulatory Features

The DSIMs in place for Missouri's utilities contain provisions not only for recovery of program costs and lost revenues resulting from the programs, but also the opportunity for shareholder incentive awards. These incentive awards are based on a percentage of net shared benefits. Lost revenues are calculated using deemed savings, while shareholder incentive awards are determined based on program evaluations.

MEEIA's provisions supporting energy efficiency are not mandatory but are designed to make energy efficiency a good business investment. The statute states:

> The Commission shall permit electric corporations to implement Commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings.

Decoupling requires periodic adjustments to true up rates and allowed revenues; these adjustments are viewed as rate-making outside of general rate cases. Some parties believe Missouri's existing statutes could be interpreted so as to allow decoupling. To date there have been no decoupling proposals associated with DSM programs submitted to or considered by the commission.

LRAM Policy Details

The basic structure of the DSIMs established for Ameren Missouri, KCP&L, and GMO is the same, but details differ.

Ameren Missouri's DSIM was established by a unanimous stipulation and agreement among Ameren Missouri, the staff of the Missouri Public Service Commission, and other stakeholders. The DSIM (Case No. E0-2012-142) approved by the commission addresses program cost recovery, the throughput disincentive, and a performance incentive. The provision addressing net shared benefits relating to the throughput disincentive (TD) is an LRAM structured as follows:

- A sum of $30.45 million shall be added to the revenue requirement determined as if the approved MEEIA Plan did not exist and in each subsequent Ameren Missouri general rate case where new base rates will become effective before the end of the three-year period.
- The $30.45 million is equal to 90% of the estimated amount of Ameren Missouri's "throughput disincentive—net shared benefit" share. It is the annualized value of a three-year annuity of 26.34% of the actual pretax net shared benefits to be recovered to offset the throughput disincentive.
- Net shared benefits are the present value of the lifetime avoided costs for the approved MEEIA programs, using the deemed values in the technical resource manual (TRM) less the present value of all utility costs of administering the MEEIA programs. Avoided costs include energy, capacity, and transmission and distribution.[24]
- The revenue requirement addition is to be trued up according to actual monthly counts of energy efficiency measures installed and the actual monthly programs' costs based on reports provided by program implementers.

Savings used to determine the DSIM applicable to the throughput disincentive are based on measure-level deemed annual energy and demand savings and measure life. The rates for avoided energy saving and rates for avoided demand savings are deemed values. Lost revenues are recovered through either a rider or a tracker mechanism. There is no threshold requirement to receive lost revenues, and there is no limit or ceiling for lost revenue. Lost revenue recovery continues for the deemed measure life after initial program year's savings through a rider or tracker mechanism.

The Missouri PSC authorized similar DSIMs for GMO in January 2013 and for KCP&L in July 2014. The LRAM has been in place only long enough to have one completed program year subject to this rate structure for GMO, and KCP&L has not reported results to date.

Energy Savings and Financial Outcomes

It is too early in the initial program plan periods for the utilities with DSIMs in place to assess the full impacts and associated financial outcomes. Ameren Missouri is exceeding program savings targets and is on track to receive full incentive amounts. Because the DSIMs are based on deemed savings, the cost recovery amounts received by the utilities are determined by reports on actual measures installed and costs incurred in each program year. These costs are built into rate riders or trackers for the programs and recovered contemporaneously, subject to periodic true-ups. Table B6 shows program costs, energy savings, and dollars recovered in 2013.

[24] While the MEEIA rule definition of avoided cost or avoided utility cost (4 CSR 240-20.093(1)(F) allows for inclusion of probable environmental compliance costs, the Ameren Missouri avoided utility costs for net shared benefits calculation does not include probable environmental costs. However Ameren Missouri does include probable future environmental compliance costs in its assumptions of future market prices.

Table B6. Lost revenue and savings data for Missouri IOUs

	Ameren Missouri	GMO	KCP&L
LRAM $ recovered	$37,148,122	$8,424,395	Programs initiated in 2014; no results reported to date.
Program cost	$34,432,402	$2,674,537	
1-year energy savings	337,368,000 kWh	30,697,000 kWh	

Discussion

Missouri's DSIMs (addressing program costs, throughput disincentive, and shareholder performance incentive) are very new. Nonetheless, their impact has been dramatic. It is clear from discussions with Missouri stakeholders that establishing these mechanisms has enabled and encouraged affected utilities to initiate and fund large portfolios of customer energy efficiency programs.

Ameren Missouri's recent history with energy efficiency program funding illustrates the substantial effect that MEEIA and authorization of DSIMs have had. Prior to MEEIA's passage, Ameren Missouri had energy efficiency programs in place representing total utility investment of about $70 million for the three-year period 2009–2011. During this time, Ameren Missouri received only program cost recovery; there was no lost revenue recovery and no shareholder incentives. Ameren Missouri leadership viewed this business model for energy efficiency as unsustainable. As a result, the utility put the brakes on its programs and reduced its program funding from $30 million in 2011 to a "bridge" of $8 million in 2012. The MEEIA rules had just been approved, and Ameren Missouri sought to retain the basic foundations of its energy efficiency programs in anticipation of getting the regulatory treatment of costs and incentives that would allow it to return to a much higher level of investment. With the commission's approval of its DSIM, Ameren Missouri's investment did indeed jump—up to $35 million in 2013, $45 million in 2014, and as much as $65 million in 2015. Both utility staff and clean energy advocates noted that having all three legs of the stool in place had a major effect on Ameren's decision to invest in energy efficiency.

As noted earlier, MEEIA does not require utilities to fund and provide energy efficiency programs. They are voluntary. Consequently, considering demand-side investments using the same investment criteria as supply and delivery infrastructure, and allowing recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs were critical for the utilities to engage fully and provide energy efficiency programs and services. To date, three of the four regulated electric utilities in Missouri have established energy efficiency programs in response to MEEIA. The remaining utility, Empire Electric, is developing proposals and initiated an MEEIA filing in late 2013.

MECHANISM COSTS

As structured, Missouri's DSIMs provide compensation to utilities for lost revenues associated with energy savings regardless of net system demands. Other states have structured LRAMs based on net system energy sales. This raises the question of whether Missouri's mechanisms are too expensive.

EVALUATION

Because Missouri's LRAMs are determined by deemed values for energy and demand savings along with measure life, the relevant program metric is the number of various measure installations achieved by the different programs. These data are reported by program contractors and staff as part of routine program tracking and are subject to prudence review by commission staff. Divergence from program projections is addressed by periodic true-ups of the DSIM.

PROCESS

Once authorized, the DSIMs are effective for the associated program period. Recovery of costs stemming from the throughput disincentive is achieved through rate riders or trackers for MEEIA programs. Parties noted that learning curve is very steep for utility energy efficiency programs. It is taking time for all involved to work through the processes and issues associated with the development, implementation, and evaluation of programs, including determination of utility incentives.

Looking Forward

The rules established for MEEIA are undergoing a required review in 2015. Missouri's regulations requiring integrated resource planning remain in place; such proceedings occur separately from MEEIA program filings.

Ameren Missouri filed its next three-year MEEIA program plan in December 2014. The existing DSIM is part of this plan. The proposed level of investment in energy efficiency programs is about the same as in the existing three-year MEEIA program plan, but expected savings are about half.

Missouri's DSIMs are too new to allow assessment of their full impact and effectiveness. It is clear that having them in place has been a critical catalyst for Missouri's electric utilities to move ahead with portfolios of customer energy efficiency programs representing significant utility investment. What is not clear yet is whether the costs of providing throughput disincentives are too high.

While more time and analysis will be needed before one can fully assess the effectiveness of Missouri's DSIMs, it already is clear that mechanisms to address the utility business model have been effective in encouraging increased efficiency in a state where no incentives were in place previously.

SOUTH CAROLINA

History

South Carolina does not require or set goals for energy efficiency. Efficiency programs are largely the result of pressure from consumer and advocacy groups. A lost revenue adjustment mechanism was first authorized in South Carolina in 2008. Initially, specific regulatory features of energy efficiency programs were tailored to each utility in the state. Investor-owned utilities approached the South Carolina Public Service Commission with proposals for efficiency programs and mechanisms to recover costs and lost margin. Commission Order No. 2009-373 issued in 2009 stated that Duke Energy Progress (formerly Progress Energy Carolinas) could "recover capital expenditures, the actual costs incurred in providing demand side management and energy efficiency programs, net lost revenues from these programs, incentives… and defer and amortize all demand side management and efficiency program expenses over a ten year period." The Commission approved a lost revenue recovery mechanism for South Carolina Electric & Gas Company (SCE&G) in 2010 (Docket No. 2009-261-E and Docket 2009-251-E). In 2013, a reestablishment of the recovery mechanism for Duke and SCE&G was ordered.

Other Relevant Regulatory Features

The South Carolina PSC has also approved shared savings incentives for investor-owned utilities. Incentives are detailed further in Nowak et al. (2015). Energy efficiency programs in the state have been influenced by programs run by interconnected utilities in North Carolina, where a combined renewable and energy efficiency portfolio standard is in place. Furthermore, a settlement agreement associated with a merger between Duke Energy Carolinas and Progress Energy Carolinas stipulated annual energy savings targets equivalent to 1% of retail sales over the time period 2014–2018.

LRAM Policy Details

South Carolina's lost revenue adjustment mechanism was established in S.C. Code Ann § 58-37-20 and further described in Docket No. 2008-251-E (Order No. 2009-373). Lost revenues are based on estimated net energy savings multiplied by the retail rate less fuel and variable operating and maintenance costs. Utilities are required to hire third parties to evaluate efficiency programs. Lost revenues are estimated annually and trued up once evaluation reports become available. Lost revenues can be collected for three years after measure installation or the life of the measure, whichever is shorter. The South Carolina Office of Regulatory Staff (ORS) publishes a report in every demand-side management rider recovery docket, which is publicly available.

Under the most recent mechanism approved for one utility, a percentage of *estimated* net lost revenue is approved for recovery. During the first year, the estimate is recovered at 75%, the next year at 80%, and in subsequent years 90% and 100%. This stepped recovery is meant to allow estimates to be recalculated as data become available and to avoid unnecessary true-ups. Other utilities have adjusted their recovery to control spikes in rates when necessary and possible to do so.

Outcomes

Regulatory staff and clean energy advocates were united in their feeling that the three-legged-stool approach has been critical in encouraging IOUs to invest in energy efficiency in South Carolina. Over several years, the state's Office of Regulatory Staff (ORS) has worked with utilities to refine their approach to recovery of lost margins. Generally, there is broad support for the LRAM within the state, although some stakeholders noted that South Carolina is still achieving relatively low levels of savings when compared with other states.

ENERGY SAVINGS

South Carolina's energy savings have steadily climbed since the introduction of the LRAM and performance incentives. Figure B6 shows statewide electricity savings and the national median.

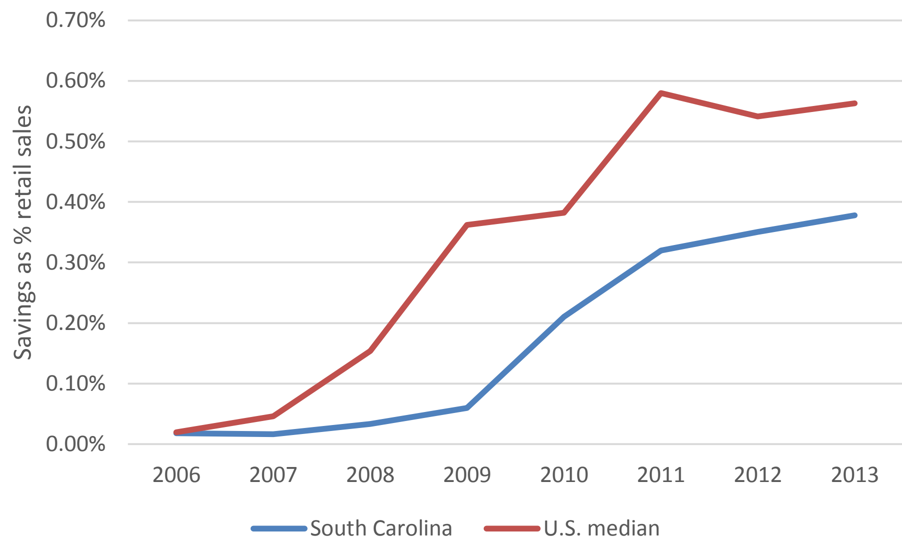

Figure B6. Net incremental savings as a percentage of retail sales for South Carolina compared with US median electricity savings. *Source:* ACEEE *State Energy Efficiency Scorecard* 2007–2014.

Though South Carolina remains below the national median, stakeholders noted that utilities have performed well in recent years relative to others in the region. However efficiency advocates also noted that savings have varied from year to year for each utility, with good years and bad years.

Regulatory staff also noted that policy mechanisms have changed several times in recent years. Thus, making assertions about the effect of a single mechanism *type* is nearly impossible.

FINANCIAL OUTCOMES

The most recent estimates of lost revenue earnings from efficiency programs are presented in table B7. South Carolina utilities are able to recover lost revenues from each program year for three years. Approved recovery for the relevant program year over the three-year period is also shown.

Table B7. Lost revenue recovered in recent years

Utility	LRAM $ for program year	Cost of energy efficiency programs	Total energy savings achieved	LRAM $ for approved 3-year timeframe
		2013		
SCE&G	$4,215,715	$15,890,902	57,333,000	$20,568,683
Duke Energy Progress	$3,527,268	$6,580,487	35,580,042	$11,294,650
Duke Energy Carolinas	$4,034,970	$17,133,555	120,352,634	$11,332,427

Utility	LRAM $ for program year	Cost of energy efficiency programs	Total energy savings achieved	LRAM $ for approved 3-year timeframe
		2014		
SCE&G	$6,432,465	$17,106,108	101,404,418	$27,001,148
Duke Energy Progress	$4,673,374	$6,452,562	23,899,720	$10,718,207
Duke Energy Carolinas	$3,985,437	$17,928,851	104,117,911	$10,116,293

Source: South Carolina Office of Regulatory Staff.

Discussion

After several years of LRAM in South Carolina, mechanisms have been adjusted to promote consistency between utilities and to mitigate potential effects on consumers. Overall, stakeholders expressed that there was limited opposition to South Carolina's LRAM and other utility incentives. All parties believed these regulatory mechanisms were necessary to encourage efficiency, although some said they would like to see more aggressive efforts to achieve energy savings from IOUs.

PROTECTING CONSUMERS

South Carolina's flexible approach to cost recovery is meant to protect consumers from rate shocks. Regulatory staff noted that estimates of lost revenues can be dramatically different from actual lost revenues, and a flexible approach to collection of lost margin minimizes large adjustments that would show up on customers' bills. Utilities in the state have also sought other ways of minimizing bill impacts. For example, SCE&G is investing heavily in nuclear power plants, leading to rising rates for customers. In order to shelter customers from the impact of an additional efficiency rider, the utility has deferred the collection of program costs. It is unclear what the future implication of this deferral will be for consumers.

TRANSPARENCY

Stakeholders emphasized the importance of transparency in South Carolina's LRAM. While clean energy advocates felt that data are generally available, other parties believe transparency could be improved. For example, utilities could submit clearer evidence of what savings were achieved over specific time periods. Since not all measures are subject to the three-year EM&V framework, it can be difficult to parse out specific savings and lost revenues associated with a particular program year. In an effort to make regulation more straightforward and to better align EM&V processes with ratemaking processes, the commission recently approved a new schedule for efficiency program years that aligns with the calendar year.

Looking Forward

South Carolina shows no indication that it will move away from its current approach to energy efficiency regulation. Parties noted that decoupling was largely off the table, as were energy savings targets, and the LRAM has almost no opposition. With new LRAM models approved in recent years, all stakeholders expressed hope that these will prove to be simple and transparent.

Appendix C. State Contact Questionnaire

Regulatory Structure Questions

Please briefly describe the lost revenue adjustment mechanism (LRAM) or lost contribution to fixed cost (LCFC) mechanism in your state.

1. When was it first authorized? When was the most recent version established?
2. To which utilities does it apply?
3. How are lost revenues estimated? (Please describe the basic calculation.)
4. How are the efficiency program savings that are used to determine lost revenues measured and verified? By whom?
5. Are the savings used in determination of lost revenues net or gross?
6. How often are lost revenues recovered (i.e., annually, biannually)?
7. Are there any threshold requirements for a utility to qualify to receive lost revenues? If so, please describe.
8. Is there a limit or ceiling for lost revenue recovery? If so, what is it?
9. For how long after a particular program year does lost revenue recovery for that year's programs continue?

Please provide the following information for up to 3 utilities covered by LRAM in your state. Please reference each of the two most recent program years for which data is available. Indicate program years and fill in information for each year in the table below.

	Utility 1: ____________	Utility 2: ____________	Utility 3:_____________
Program Year ______			
Lost Revenue Dollars Recovered ($)*			
Cost of energy efficiency programs to which LRAM was applied ($)			
Total (1-year annual) energy savings achieved by the programs under LRAM (Please indicate kWh or therms)			
Program Year ______			
Lost Revenue Dollars Recovered ($)*			

Cost of energy efficiency programs to which LRAM was applied ($)			
Total (1-year annual) energy savings achieved by the programs under LRAM (Please indicate kWh or therms)			

*Note: This refers to the total net lost revenues (NLR) the program year generates over the time frame NLR is approved to be collected.

Please provide a citation or reference to the official documentation (e.g., statue, regulatory order, etc.) where the lost revenue recovery mechanism is established or described.

Is there a report or other document describing the mechanism and the results of how it has worked in practice in your state, and/or provides data on the actual award for the last two program years? If so, please provide link, contact person, or reference where we may obtain a copy.

General Questions

1. Are there any suggestions you would make to another state who was thinking of adopting an LRAM such as the mechanism used in your state?

2. Please provide any additional insights or important information about regulatory adjustments to the utility business model in your state that we have not covered above.

Attachment D

ACEEE developed this technical brief in response to the Pennsylvania Public Utilities Commission's (PUC) request for comparison of the Pennsylvania models and practices with those used in other states.

The Commission is reviewing business models used by Pennsylvania utilities to determine if there are better and more cost-effective best practices that should be recommended for consideration in subsequent phases of the Act 129 program. One purpose of this comparison and assessment is to support and augment the Commission staff's capability to analyze these issues. A second purpose is to provide a framework to consider how future phases of Act 129 might best be implemented.

Based on many years of research, ACEEE has identified three regulatory tools that work best together to drive utility energy efficiency performance and to achieve statutory energy savings targets such as those in Act 129.[1] These mechanisms help to align the utility business model with the achievement of energy efficiency savings targets. The three components are program cost recovery, revenue decoupling, and performance incentives that provide meaningful earnings opportunities for achieving energy savings.[2] These regulatory policies combine to address three primary financial concerns utilities face regarding customer energy efficiency programs; (1) recovery of program expenses, (2) removal of the throughput incentive (revenues and profits increase with higher energy sales), and (3) provision of earnings opportunities for shareholders, similar to electric supply-side investments.[3]

The remainder of this document is organized as follows. First, we provide a summary description of our understanding of the policy framework for utility energy efficiency programs in Pennsylvania (i.e., Act 129 and associated regulations). In the second section, we compare Pennsylvania's policy framework and electric utility energy efficiency performance results to other states'. In that section, we show how Pennsylvania compares to other states regarding the existence and nature of the key policy features (i.e., energy efficiency resource standards (EERS), program cost recovery mechanisms, revenue decoupling, and performance incentives)

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[1] We have at times referred to these as the "3-legged stool" for supporting utility energy efficiency programs, such as in York, D., and M. Kushler. 2011. *The Old Model Isn't Working: Creating the Energy Utility for the 21st Century*. Washington, DC: ACEEE. http://aceee.org/white-paper/the-old-model-isnt-working.

[2] Additional resources documenting ACEEE research findings and policy recommendations regarding utility business models that encourage energy efficiency include Kushler, M. and M. Molina. 2015. *Policies Matter: Creating a Foundation for an Energy-Efficient Utility of the Future*. White paper. Washington, DC: American Council for an Energy-Efficient Economy. http://aceee.org/policies-matter-creating-foundation-energy; ACEEE policy brief. 2014. *Utility Initiatives: Alternative Business Models and Incentive Mechanisms*. http://aceee.org/policy-brief/utility-initiatives-alternative-business-models-and-incen; York, D., M. Kushler, S. Hayes, S. Sienkowski, and C. Bell, ACEEE and S. Kihm, Energy Center of Wisconsin. 2013. *Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation*. Washington, DC: American Council for an Energy-Efficient Economy. http://aceee.org/sites/default/files/publications/researchreports/u133.pdf

[3] Kushler, M. and M. Molina. *Policies Matter: Creating a Foundation for an Energy-Efficient Utility of the Future*. White paper. Washington, DC: American Council for an Energy-Efficient Economy. http://aceee.org/policies-matter-creating-foundation-energy

and in terms of utility energy efficiency savings results. In the third section, we discuss the results of our analysis and offer suggestions for possible improvements for future phases of Act 129.

The Current Pennsylvania Energy Efficiency Policy Framework

Pennsylvania Act 129

Act 129 provides the basic policy framework for utility energy efficiency programs in Pennsylvania. Act 129 meets ACEEE's definition of an energy efficiency resource standard (EERS): it requires utilities to obtain specific, long-term (three years or more) energy savings levels through customer energy efficiency programs.

With regard to the three basic components of the "3-legged stool" for energy efficiency program support, Act 129 contains the following:

- **Cost recovery**: Act 129 directs the Commission to establish cost recovery mechanisms for each electric distribution company (EDC) that recover all energy efficiency program costs. The mechanisms are similar to other states with EERS. However the statute sets a cap on energy efficiency program spending:

  "Limitation on costs.--the total cost of any plan required under this section shall not exceed 2% of the electric distribution company's total annual revenue as of December 31, 2006."
  [Section 2 (G)]

- **Decoupling**: Act 129 appears to preclude a utility from utilizing decoupling:

  "Except as set forth in paragraph (3) [i.e., a rate case], decreased revenues of an electric distribution company due to reduced energy consumption or changes in energy demand shall not be a recoverable cost under a reconcilable automatic adjustment clause."
  [Section 2 (K) (2)]

  Some parties have argued that there may be some flexibility for PUC discretion regarding decoupling-type approaches under current statutes.[4]

- **Performance Incentives**: We were unable to find any reference to utility company incentives for energy efficiency performance in the energy efficiency section of Act 129.[5]

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[4] E.g., see Comments of the Keystone Energy Efficiency Alliance (et.al.), in the En Banc hearings, Docket No. M-2015-251883 March 16, 2016.

[5] It should be noted that Act 129 does contain provisions for a financial penalty to be assessed on a utility for failing to achieve the required energy savings. States with EERS policies have generally not utilized penalties. While penalties can encourage utilities to avoid failure, they do not reward excellent performance above the minimum. Moreover they can cause utilities to seek to minimize risk by advocating for lower energy-savings targets or for having no EERS targets at all.

Various parties have argued that the PUC has authority to establish incentives for utility energy efficiency performance under current statutes.[6]

POLICY FRAMEWORK SUMMARY

Pennsylvania has an energy efficiency resource standard specifying energy savings targets for electric utilities. It also has a designated cost-recovery mechanism, albeit with a spending cap. Pennsylvania does not currently use two of the primary regulatory tools for aligning utility business models with achievement of energy savings targets: revenue decoupling and performance incentives for EDCs.

Pennsylvania Policy Framework and Energy Efficiency Performance Compared to Other States

In this section we compare Pennsylvania's policy framework to other states, on four key policy criteria: (1) presence of an energy efficiency resource standard (EERS); (2) presence and nature of cost recovery provisions; (3) revenue decoupling; and (4) incentives for utility energy efficiency performance. We also compare Pennsylvania to other states on energy efficiency performance, using 2016 electricity savings as a percent of retail sales as a metric.

THE IMPORTANCE OF A POLICY FRAMEWORK

Absent specific policy provisions to support and/or require utility energy efficiency programs, the default condition under traditional cost-of-service regulation is to support a utility business model that rewards utilities for increasing sales and revenues. That approach foregoes the cost-effective energy savings and the economic and other benefits of increased energy efficiency.[7] The core objective of policy provisions to encourage utility energy efficiency action is to counteract the effects of those disincentives for promoting customer energy efficiency that are inherent in traditional regulation.

ENERGY EFFICIENCY RESOURCE STANDARDS

The most effective policy instrument to facilitate substantial utility energy efficiency efforts and achievements is an energy efficiency resource standard.[8] An EERS is a binding energy savings target for utilities or third-party program administrators of at least three years, with savings to be achieved through energy efficiency programs for customers.[9] Twenty-six states currently have an EERS in place.[10]

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[6] E.g., see Comments of the Keystone Energy Efficiency Alliance (et.al.), in the En Banc hearings, March 16, 2016; and Legal Comments of NRDC in Docket No. M-2015-251883, May 25, 2017.

[7] E.g., reduced environmental emissions, increased local employment, and improved business productivity.

[8] Kushler, M. 2014. "IRP vs. EERS: There's one clear winner among state energy efficiency policies." Blog post. December 16, 2014. http://aceee.org/blog/2014/12/irp-vs-eers-there%E2%80%99s-one-clear-winner-

[9] ACEEE policy brief. "State Energy Efficiency Resource Standards (EERS)." January 2017. http://aceee.org/sites/default/files/state-eers-0117.pdf

[10] It is noteworthy that states tend to be successful at achieving their EERS savings targets. In 2011, 24 of 26 states saved 80% or more of target. In 2012, 25 of 26 states saved 80% or more of that year's energy savings target. In aggregate across the nation, states with an EERS hit 110% of the total MWh savings target. (See: Downs, A. and C. Cui. 2014. *Energy*

Pennsylvania is one of these states, with Act 129 requiring the seven major EDCs to develop energy efficiency and conservation plans and administer cost-effective energy efficiency programs to achieve the required minimum savings levels. Phase III implementation of Act 129 includes targets for each EDC over a five-year period. Pennsylvania energy savings targets are lower than those of most other states with an EERS. Averaging targets across the Pennsylvania EDCs, the total savings requirement is about 0.8% incremental electricity savings per year.[11] As shown in table 1, Pennsylvania ranks 21st in approximate average annual electric savings targets as a percentage of retails sales, for the years 2016-2020.

Table 1. Comparison of average annual incremental savings targets among states with EERS

Rank	State	Approx. annual electric savings target (2016-2020)	Approx. % electric retail sales covered by EERS
1	Massachusetts	2.9%	86%
2	Rhode Island	2.6%	99%
3	Arizona	2.5%	56%
4	Maine	2.4%	100%
5	Vermont	2.1%	100%
6	Maryland	2.0%	100%
7	Illinois	1.7%	89%
8	Connecticut	1.5%	93%
9	Minnesota	1.5%	86%
10	Washington	1.5%	79%
11	Hawaii	1.4%	100%
12	Colorado	1.3%	57%
13	Oregon	1.3%	69%
14	California	1.2%	78%
15	Iowa	1.2%	74%
16	Michigan	1.0%	100%
17	New Hampshire	1.0%	100%
18	Ohio	1.0%	89%
19	Arkansas	0.9%	53%

Efficiency Resource Standards: A New Progress Report on State Experience. Washington, DC: ACEEE. http://aceee.org/research-report/u1403)

[11] Pennsylvania Public Utility Commission. 2015. Energy Efficiency and Conservation Program Docket No. M 2014-2424864 Implementation Order. Table 6, p. 51. http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/energy_efficiency_and_conservation_ee_c_program.aspx

Rank	State	Approx. annual electric savings target (2016-2020)	Approx. % electric retail sales covered by EERS
20	Wisconsin	0.8%	100%
21	**Pennsylvania**	0.8%	97%
22	New York	0.7%	100%
23	New Mexico	0.6%	68%
24	Nevada	0.4%	62%
25	North Carolina	0.4%	99%
26	Texas	0.1%	70%
	Average	**1.3%**	

Source: ACEEE State Scorecard 2017

Pennsylvania ranks in the bottom quartile of energy savings targets among states with an EERS. It should be noted that advancing on this savings metric would be difficult under the existing 2% cost cap, which restricts EDCs from expanding program offerings and increasing the funding of customer incentives for energy savings. We compare Pennsylvania 2016 program spending with other states in the next section of this document.

PROGRAM COST RECOVERY

The function of program cost recovery is to ensure that utilities are made whole for energy efficiency program direct costs. All states that require regulated electric utilities to offer energy efficiency programs also have program cost-recovery mechanisms in place. While having these mechanisms is a prerequisite for energy efficiency in cost-of-service regulation, the type of cost-recovery mechanism is not a primary driver of increased energy savings. The Act 129 implementation orders require EDCs to include a proposed cost-recovery tariff mechanism in their Energy Efficiency and Conservation (EE&C) program plan filings. EDCs' energy efficiency program costs are recovered annually and trued-up to actual costs each year. The Act requires all EDCs to recover all costs incurred on a full and current basis from customers through a reconcilable adjustment clause.

Pennsylvania's energy efficiency program cost-recovery mechanisms are similar to those of other states. ACEEE collected 2017 data on 41 large regulated electric utilities in 30 states (not all utilities responded to each question in the data request). Twenty-seven of 34 utilities responding to the question have one-year collection periods, the same as Pennsylvania EDCs. Of the 38 utilities responding to the question, 25 use a rider, tracker, or public benefits charge on customer bills as the cost-recovery mechanism. The terminology and definitions of the fees and charges vary by state. Pennsylvania uses a reconcilable rider mechanism. The remaining 13 utilities recover costs though base rates or a combination of mechanisms.

Table 2 provides examples of utility cost-recovery mechanisms applicable to specific utilities in other states. In some cases, the collection mechanism funds not only program cost recovery but also performance incentives, lost revenue adjustments, annual adjustments to true-up collections with actual costs, or other costs.

Table 2. Examples of energy efficiency cost recovery mechanisms

Utility State Type of cost-recovery mechanism	Description of cost-recovery mechanism
Ameren Missouri Missouri Rider	Program costs are recovered in the year they occur through the Energy Efficiency Investment Charge (Rider EEIC). The charge appears on customer bills as "Energy Efficiency Invest Chg." The 2016-18 EE Plan, approved in 2014, notes that the "rider will be based on annual collection of 100% of the forecasted program costs and 100% of the forecasted throughput disincentive collected contemporaneously with their incurrence, with true-ups to match billed revenues to the costs and throughput disincentive experienced." Since this mechanism also addresses the throughput disincentive, collections go beyond basic program cost recovery.
Arizona Public Service Arizona Combination of base rates and DSM adjustment charge	APS collects most program costs through the DSM Adjustment Charge (DSMAC). In addition, the utility collects $10 million annually through base rates. DSMAC is included in another charge on customer bills.
Centerpoint Texas Rider	Centerpoint recovers program costs as one component of charges called the Energy Efficiency Cost Recovery Factor (EECRF). The EECRF is calculated annually to equal, by rate class, the sum of forecasted energy efficiency costs, adjustment for past over- or under-recovery, performance incentives, any previous year's EECRF proceeding rate case expenses, and EM&V costs; divided by the forecasted billing units for each class.
ConEdison New York In base rates or in surcharges, varies by program	For programs recovering costs through rates, direct program costs are amortized over the collection period (~10 years). Labor and indirect program costs are recovered through base rates. For programs recovering costs through surcharges, the surcharge authorizes an annual collection amount that creates a liability on collection. When direct program costs are incurred, they are booked against the liability. Labor and indirect program costs are recovered through base rates.
Dominion Energy Virginia Rate adjustment clause including margin	The utility may petition for an adjustment clause up to once per year for the projected and actual costs to design, implement, and operate energy efficiency programs, including a margin to be recovered on operating expenses, equal to the general rate of return on common equity.
Eversource Connecticut Public benefits charges collected on customer bills	Ratepayer contributions to the EE fund are collected on the program year/period that the funds are expensed. However in the instances when the EE fund account has an unspent balance, the carryover amount is transferred to the following program year.

Utility State Type of cost-recovery mechanism	Description of cost-recovery mechanism
NIPSCO Indiana Tracker with annual true-up	Through a tracker mechanism, costs are recovered annually by including an estimate of costs for the upcoming 12 months and an adjustment for a reconciliation of previously estimated costs with the actual costs that occurred for the previous 12 months, including a true-up of lost revenues based on evaluation, measurement, and verification of program savings.
PPL Electric Utilities Pennsylvania Rider with annual true-up	Costs are recovered through a reconcilable rider mechanism that trues-up to actual expenses each year.
Public Service (Xcel Energy) Colorado In base rates and rider adjustments	Approximately $89 million of annual DSM costs are recovered through base rates, with any spending over or under this amount adjusted through the DSM Cost Adjustment rider. Any incentive and disincentive value is included in this cost recovery.
We Energies Wisconsin In base rates	The Public Service Commission of Wisconsin requires energy efficiency/conservation program costs to be trued-up through escrow accounting. Program charges are deferred into the escrow account as incurred and expensed based on current cost recovery authorized in the most recent base rate case. Any over- or under- recovery in the current year is carried forward to be included in future ratemaking.

The takeaway on the cost recovery issue is that there are many different technical approaches for facilitating cost recovery for utility spending on energy efficiency programs. Pennsylvania's current approach for cost recovery seems adequate for accomplishing that task. Of more concern is the spending cap that is incorporated in current policy.

PENNSYLVANIA'S SPENDING CAP ON COST RECOVERY

Act 129 imposes a spending limit of two percent of 2006 annual revenue for EDCs' energy efficiency program costs. Specifically, "the total cost of any plan must not exceed two percent of the EDC's total annual revenue as of December 31, 2006, excluding LIURP, established under 52 Pa. Code § 58 (relating to residential Low Income Usage Reduction Programs). 66 Pa. C.S. § 2806.1(g)."[12] Table 3 shows the percentage of electric utility revenues invested in energy efficiency program spending. Pennsylvania ranks 21st of the 26 states with electric EERS.

[12] Pennsylvania Public Utility Commission. 2015. Energy Efficiency and Conservation Program Docket No. M 2014-2424864 Implementation Order. http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/energy_efficiency_and_conservation_ee_c_program.aspx

Because the spending cap is based on 2006 annual revenues, Pennsylvania EDC spending on energy efficiency as a percent of current-year revenues has declined over time as revenues have increased. This lack of indexing to current revenues lowers Pennsylvania's rank relative to other states that continue to increase energy efficiency investments. Note in table 3 that Pennsylvania's total energy efficiency spending as a percent of statewide electric revenues is 1.55% of 2016 revenues, not 2%.

Table 3. Electric energy efficiency program spending as percent of statewide electric revenues for EERS states

Rank	State	2016 Electric energy efficiency program spending ($million)	Percent of statewide electric revenues
1	Vermont	54.0	6.84%
2	Rhode Island	78.4	6.42%
3	Massachusetts	538.9	6.25%
4	Washington	291.2	4.29%
5	Connecticut	191.9	3.85%
6	Oregon	156.6	3.79%
7	California	1364.1	3.50%
8	Iowa	119.2	2.86%
9	Minnesota	161.9	2.50%
10	Maryland	186.8	2.49%
11	Maine	32.3	2.21%
12	Illinois	262.8	2.05%
13	New York	425.2	2.00%
14	Arkansas	68.7	1.86%
15	Hawaii	37.0	1.64%
16	Colorado	87.2	1.63%
17	New Mexico	34.3	1.62%
18	Nevada	49.0	1.62%
19	Michigan	182.1	1.58%
20	Arizona	126.7	1.56%
21	**Pennsylvania**	229.4	1.55%
22	New Hampshire	23.2	1.36%
23	North Carolina	144.6	1.17%
24	Ohio	141.0	0.98%
25	Wisconsin	74.1	0.98%
26	Texas	194.1	0.60%
	Median	**142.8**	**1.93%**

Rank	State	2016 Electric energy efficiency program spending ($million)	Percent of statewide electric revenues
	Average		**2.59%**

Because the spending on energy efficiency programs is logically (and in actual experience) closely related to the amount of energy efficiency savings achieved, it is not surprising that Pennsylvania ranks 21st among states in both the percent of revenues spent on energy efficiency (Table 3) and the projected target for savings achieved as a percentage of sales (Table 1). Pennsylvania also ranks a very similar 19th in actual savings as a percentage of sales in 2016 (Table 4 below.)

REVENUE DECOUPLING

True symmetrical revenue decoupling (i.e., "full decoupling") adjusts for deviations (both upward and downward) of actual sales from the levels forecasted when rates were set.[13] The purpose of revenue decoupling is to address the basic throughput incentive that utilities face under traditional regulation, which creates an inherent disincentive regarding customer energy efficiency and an inherent incentive to pursue sales increases. By adjusting for any sales shortfall, decoupling ensures full recovery of the authorized revenue requirements independent of sales volume. This removes a key disincentive for utilities regarding the promotion of energy efficiency. At the same time, true symmetrical decoupling protects customers by requiring utilities to refund excess revenues when electricity sales exceed the forecast. This removes any incentive for the utility to encourage wasteful use of energy.

Decoupling changes the regulatory incentive structure under which the utility operates, altering its business model. Without revenue decoupling, the utility will have an economic incentive to increase sales rather than to pursue significant energy savings through customer energy efficiency programs. Without decoupling, a utility will also tend to resist policies requiring it to promote customer energy efficiency improvements. Decoupling alone is not sufficient to produce strong utility performance regarding customer energy efficiency, but it does remove one important obstacle to strong performance.

Consistent with these factors, we see a strong correlation between states achieving high savings results and those employing revenue decoupling. Among the top 14 states with electric EERS ranked by incremental annual savings, 11 have revenue decoupling. As a group these states averaged 1.75% annual incremental savings in 2016. As of July 2017, 15 states had an electric revenue decoupling policy in place and have implemented that policy by approving decoupling for at least one major utility.[14]

Table 4 ranks states with an EERS by 2016 energy savings as a percent of sales and indicates whether they had revenue decoupling in place for at least one electric utility at that time.

[13] RAP (Regulatory Assistance Project). 2016. *Revenue Regulation and Decoupling: A Guide to Theory and Application.* Montpelier, VT: Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf

[14] ACEEE State Policy Database. https://database.aceee.org

Table 4. Comparison of EERS states saving with and without decoupling

State	Net incremental 2016 electric savings as % of sales	Decoupling in effect 2016
Massachusetts	3.00%	Yes
Rhode Island	2.85%	Yes
Vermont	2.52%	Yes
Washington	1.54%	Yes
California	1.54%	Yes
Connecticut	1.53%	Yes
Arizona	1.42%	No
Maine	1.38%	Yes
Hawaii	1.32%	Yes
Minnesota	1.31%	Yes
Illinois	1.23%	No
Michigan	1.17%	No
Oregon	1.16%	Yes
New York	1.09%	Yes
Iowa	1.01%	No
Maryland	0.91%	Yes
Colorado	0.89%	Yes
Ohio	0.87%	Yes
Pennsylvania	0.73%	No
Arkansas	0.68%	No
Nevada	0.63%	No
Wisconsin	0.61%	No
New Mexico	0.59%	No
New Hampshire	0.58%	No
North Carolina	0.57%	No
Texas	0.19%	No
Average with decoupling	**1.6%**	
Average without decoupling	**0.8%**	

States with both EERS and decoupling achieved energy savings averaging 1.6% of MWh sales in 2016. Pennsylvania and other states with EERS but no decoupling saved only half as much, 0.8% of sales.

Performance Incentives

While decoupling and cost-recovery mechanisms are designed to reduce the disincentive to acquire energy savings, the function of performance incentives is to provide a positive incentive. Performance incentives, sometimes called shareholder incentives for investor-owned utilities, enable utilities to achieve some earnings from their energy efficiency activities. Because utilities have well-established mechanisms for earnings from supply side investments, this is important for persuading utility management to seriously pursue energy efficiency objectives.

Twenty-nine states have performance incentives in place for meeting electric savings targets, including 20 of the 26 states with EERS.[15] As with decoupling, there is a strong correlation between the presence of performance incentives in a state and the energy savings achieved by utilities in those states. States with performance incentives in place averaged more than twice the energy savings of states without performance incentives. The average 2016 net incremental savings (MWh) as a percent of retail sales for states with incentives was 0.97%, while those without performance incentive policies averaged only 0.43%.

There is also a strong correlation between the states with the highest savings targets and those with performance incentives. Ten of the top 14 states with EERS policies, ranked by average annual savings targets for 2016-2020, award financial incentives to utilities for hitting their targets. We have observed that the presence of performance incentives in the policy package may actually be helpful in facilitating a state's ability to establish a strong EERS, by encouraging utilities to cooperate rather than oppose the EERS policy. In that regard, it is noteworthy that utilities tend to be successful in earning their performance incentives. In 2015, ACEEE collected data on 19 states with incentive mechanisms in place and found that regulated utilities achieved sufficient savings to earn at least some incentive payment in each of those states.[16]

The specific performance incentive mechanisms used to facilitate achievement of those energy efficiency program savings vary from state to state. To facilitate comparisons, here we summarize the approaches based on the four primary ways to calculate incentives: 1) as a share of net benefits, 2) energy savings-based incentives, 3) multifactor, and 4) rate of return.[17] Most have a threshold savings level set as the achievement of a minimum amount of energy savings. Most states also have some type of upper limit to the amount of incentive that can be earned, so that the incentive level is "reasonable" and does not become a target for criticism. Each incentive calculation type is described below.

Shared net benefits. Shared net benefits mechanisms give utilities the opportunity to earn some portion of the benefits of a successful energy efficiency program that otherwise would all go to

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[15] The remaining nine states award performance incentives for the achievement of savings targets that do not qualify as EERS under our definition.

[16] Nowak, S., B. Baatz, A. Gilleo, M. Kushler, M. Molina, and D. York. 2015. *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*. Washington, DC: ACEEE. http://aceee.org/beyond-carrots-utilities-national-review

[17] Nowak, S., B. Baatz, A. Gilleo, M. Kushler, M. Molina, and D. York. 2015. *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*. Washington, DC: ACEEE. http://aceee.org/beyond-carrots-utilities-national-review

the ratepayers. The incentive payment amount is usually a percentage of the positive difference between the costs (efficiency program spending) and the benefits (the dollar valuation of energy savings achieved as a result the program). This approach also has a savings-based element, in that most have a threshold level set as the achievement of a minimum percentage of the energy savings performance goal for the utility. We call it shared net benefits because the incentive amounts are driven by net benefits; the greater the net benefits, the higher the incentive payment amount. In most cases, there is a cap or maximum incentive, although some of these limits are defined as a percentage of net benefits rather than a fixed dollar amount.

Energy savings-based incentives. Savings-based incentives reward utilities for achieving, and sometimes for exceeding, pre-established energy savings goals, measured in kWh. Often, these energy savings targets for utilities may be tied to or derived from statewide EERS policies. For example, if the utility energy efficiency programs save 100% of the target, they are eligible for some particular amount of an incentive payment. Five of the six states with savings-based incentives have EERS policies. The amount of the financial incentive the utility earns is often calculated as a percentage of total program spending or budget in a tiered structure (e.g., achieve 100% of the savings target, receive an amount equivalent to 6% of the program spending; achieve 110% and receive 8%; and so on), but driven by the program energy savings achieved.

Multifactor mechanisms are those in which the calculation of performance incentive amounts includes multiple metrics. Energy savings are just one of several metrics that are typically used to determine the amount of incentive earned. For example, financial incentives may also be tied to demand savings, job creation, or measures of customer service quality. This type of approach is found in a handful of states where the mechanism is used to forward the achievement of several regulatory and public policy goals at the same time.

Rate of return incentives are far less common. They allow utilities to earn a rate of return based on efficiency spending. This creates a correspondence between demand side (energy efficiency) spending and supply side (generation and transmission) investments. For example, a utility may earn a rate of return for efficiency investments equivalent to or comparable to the rate it earns for new energy supply capacity investments.[18] One aspect which make this approach less desirable is that it technically rewards spending rather than actual energy savings.

Discussion and Options for Strengthening Utility Energy Efficiency Policy

The comparative results presented above demonstrate that there are four components of state energy efficiency policy frameworks consistently associated with high energy savings: robust energy savings targets in the form of EERS; program cost-recovery mechanisms with no cost cap; revenue decoupling; and performance incentives for achieving energy savings targets.

States with the strongest energy efficiency performance tend to share common policy features. For example, in 2016, all of the top 10 states in terms of savings as a percent of sales had an EERS, nine of the top 10 had decoupling, and eight awarded performance incentives. The top

[18] Amortizing the recovery by the utility of the cost of programs over multiple years may also be considered a rate of return incentive in some instances, if the utility earns a return on the balance after the first year.

ten energy-saving states averaged 1.84% net savings and average energy efficiency spending was 3.9% of statewide electric revenues.

Looking beyond past energy savings to future potential, we also see that relatively high EERS savings targets are most commonly paired with the complementary policies examined in this report. Among the top 14 states with electric EERS ranked by average incremental annual targets for 2016-2020, 13 have revenue decoupling and 10 award performance incentives. In the top five, all with average annual targets above 2%, four have decoupling, four use performance incentives, and three have both.

Twenty-nine states have performance incentive policies in place for electric utilities, and 15 have implemented decoupling for electric utilities. Pennsylvania is among the 17 states using neither decoupling nor performance incentives. Pennsylvania is among only 3 of 26 states with an EERS, but not decoupling or performance incentives.

Considerations for Future Phases of Act 129 Implementation

If Pennsylvania would like to enhance the energy savings accomplishments of its electric utilities, our review of experience in other states leads us to recommend that the Commission, staff, and stakeholders explore the following initiatives. While these are not all within the power of the PUC to accomplish without new legislation, other states' experiences have consistently demonstrated that they are essential policy elements for high energy efficiency performance.

1) Drive greater energy savings by adopting higher savings targets for EDCs (i.e., a stronger EERS), either at the Commission level or the legislative level. Because Pennsylvania targets are well below average savings goals set by other states, it is reasonable to assume that more energy savings can be cost-effectively captured for consumers across the Commonwealth.

2) Eliminate artificial constraints to efficiency spending by removing the 2% spending cap on utility energy efficiency expenditures through legislative action. This is likely a necessary step to enable the achievement of higher savings targets.[19]

3) Continue to examine the Commission's ability to develop performance incentives that encourage EDCs to meet or exceed energy savings goals. Performance incentive structures that are based on verified energy savings and have reasonable caps can effectively encourage EDC achievement of energy savings while protecting consumers.

4) Consider the feasibility of adopting full revenue decoupling. Several stakeholders have presented arguments that Act 129 may permit some form of decoupling. However we acknowledge that it would be ideal to clarify that authority through legislation.

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[19] The requirement for cost-effectiveness is a de facto protection against imprudent excess expenditures of ratepayer dollars. It makes no sense to artificially limit the expenditures on a cost-effective resource.

In summary, the national data are clear. Virtually all of the leading states on utility energy efficiency achievements have a set of policies that include a strong EERS, performance incentives for utilities, and true revenue decoupling.

Further Research

We appreciate this opportunity to present comparisons of the Pennsylvania energy efficiency models/practices with those used in other states. ACEEE is available to provide additional resources, research, and analysis of options for aligning utility business models for energy efficiency performance.

January 3, 2020

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 S Clinton Ave 9th Floor
Trenton, New Jersey 08625

Comments of Gabel Associates on the Second Energy Efficiency (“EE”) Cost Recovery Technical Meeting

Dear Secretary Camacho-Welch;

Gabel Associates, Inc. (“Gabel Associates” or “Gabel”) is pleased to provide comments regarding the second EE Technical Meeting focused on Cost Recovery, which occurred on December 13, 2019. Our comments to the first EE Technical Meeting focus on Cost Recovery, which occurred on October 31, 2019, contained extensive discussion on each of the topics subsequently discussed in the second EE Technical Meeting focused on Cost Recovery. Our comments to the first EE Technical Meeting focused on Cost Recovery have been provided as an attachment to these comments for your convenience.

Following the second EE Technical Meeting focused on Cost Recovery on December 13, Board of Public Utilities (“BPU”) Staff provided four (4) cost recovery scenarios for stakeholder comment. These comments focus primarily on the details of these four cost recovery scenarios, but also provide some general observations which were largely addressed in our reply comments to the first EE Technical Meeting focused on Cost Recovery.

Gabel Associates is an energy, environmental and public utility consulting firm with its principal office located in Highland Park, New Jersey. For over 25 years, Gabel Associates has provided quality energy consulting services and strategic insight to its clients. Classified as a small business, the firm provides its expertise to a wide variety of clients involved in virtually every sector of the energy industry, including public and federal agencies, individual commercial and industrial end users, aggregated groups of customers, public utility commissions, power plant owners and operators, wholesale suppliers, and utilities. The firm frequently provides expert testimony and reports on utility ratemaking issues throughout the country.

Our recent work in New Jersey has included assisting several of the State’s electric and natural gas utility companies develop and design cost effective energy efficiency (“EE”) programs. Specifically, we have worked or are currently working on EE related activities with Atlantic City Electric Company (“ACE”), Public Service Electric and Gas Company (“PSE&G”), Elizabethtown Gas Company (“Etown”), New Jersey Natural Gas Company (“NJNG”), and South Jersey Gas Company (“SJG”). It is our understanding that these companies will file supplemental comments as well.

Gabel Associates also provides extensive consulting services to customers in New Jersey including hundreds of school districts, counties, and business customers, as well as services to utility commissions and wholesale market participants. Because of the breadth of sectors where we provide our services, we have a deep and balanced sensitivity to the needs of all types of energy market participants. The principals of Gabel Associates include two individuals who served as senior managers at the BPU where they were both extensively involved in utility ratemaking, cost of service, and tariff design issues.

This set of comments focuses on three components: (1) reactions to the scenarios tendered by the BPU; (2) suggestions on a preferred cost recovery design to maximize EE achievement and protect ratepayers; and, (3) a discussion of other issues regarding cost recovery.

1. Prescribed BPU Cost Recovery Scenarios

At the second EE Technical Meeting focused on Cost Recovery BPU Staff provided two cost recovery scenarios and requested stakeholder input on the proposed solutions. Following that meeting, BPU also provided two additional scenarios for review by stakeholders. This section provides an overview of each scenario, as well as our comments on the reasonableness of the proposed scenarios. We do not address incentives/penalties as more information is needed to undertake such an analysis.

a. BPU Staff Scenario 1

Asset / Investment Treatment	Expense
Recovery Period	Annual
Lost Revenues	No Decoupling
Incentives/Penalties	% of Savings (Weighted by QPI Performance) / $ for Negative Benefits (Weighted by QPI Performance)
Carrying Cost on Over/Under Recovery	T-Bill
WACC	None
Rate Cap	2% annual increase of total customer bill

Scenario 1 illustrates a set of cost recovery elements that would severely restrict achieving the goals of the Clean Energy Act ("CEA"). Expensing program costs is problematic for three reasons: (1) the bill impacts of program recovery are very high in the early years because all costs would be recovered in a single year instead of spreading them across multiple years; (2) expensing costs disconnects benefits and costs – amortization would match cost recovery with receipt of benefits; and, (3) expensing costs without allowing utilities to earn a return on investment places EE investments at a financial disadvantage against traditional utility investments, which may result in capital allocations to other projects with higher earnings opportunities. Also, there is clear legislative intent supporting utilities ability to earn a return on these investments. EE initiatives are an alternative to investing in traditional assets and yield environmental and customer benefits. The rate recovery mechanism should not act as a disincentive.

In terms of lost revenue recovery, a scenario without decoupling does not remove the throughput incentive for utilities (i.e. the financial incentive to increase utility throughput as that will increase revenues and earnings), and encourages a culture of promoting higher sales, which is counter to the State policy goal of reducing energy consumption. Finally, a scenario without decoupling (or a lost revenue adjustment mechanism) is counter to the provisions in the CEA which explicitly allow utilities to recover lost revenues from programs.

The 2% rate cap will place a significant limit on EE spending, which will restrict the available energy savings opportunities. This is further compounded in a scenario that relies on expensing program costs in a single year. If BPU considers implementing a rate cap, it will likely need to reduce the energy savings targets as a cap will not allow the State to spend the necessary money to meet the goals and realize the associated benefits.

Most stakeholders active in the discussion at the December 13, 2019 Technical Meeting expressed concern that this Scenario would not achieve the desired outcome of the CEA.

b. BPU Staff Scenario 2

Asset / Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Full Decoupling
Incentives/Penalties	Fixed Dollar Incentive/ Fixed Dollar Penalty (Thresholds related to QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case
Rate Cap	No Cap

Scenario 2 contains critical elements that would foster an environment of EE achievement and priority for customer savings while protecting ratepayers. Amortization of costs at the WACC not only reduces rate shocks associated with single year expensing, but also aligns EE with traditional utility investments providing financial incentives (in conjunction with decoupling) for utilities to achieve the energy savings targets. In addition, by amortizing over the weighted average measure life, there is a matching of costs and savings.

Full revenue decoupling also provides ratepayer protections because it only allows utilities to earn authorized revenues.[1] In a scenario with a lost revenue adjustment mechanism (partial decoupling) and higher than average sales due to weather or other reasons, utilities will have significant opportunity to earn higher than authorized revenues and returns. This occurs because any time actual sales exceed authorized billing determinants, utilities recover above revenues authorized in their previous rate case. Full revenue decoupling effectively adjusts the billing determinants so

[1] Authorized revenues are set in a base rate case and represent the approved pro forma revenue requirement meant to capture all plant in service depreciation expense and other costs.

that only authorized revenues are recovered.[2] This protects customers from potential over recovery and allows utilities to remain financially healthy and avoid revenue erosion caused by sales losses. This Scenario is highly preferred as the approach to achieve the goals in the CEA, unlock the potential of EE in New Jersey, and protect ratepayers.

c. BPU Staff Scenario 3

Asset / Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Limited Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill
WACC	Base Rate Case
Rate Cap	No Cap

Scenario 3 is similar to Scenario 2, with the only difference being limited decoupling and a different incentive/penalty structure. It is unclear what BPU Staff means in its reference to the term "limited decoupling". This term could mean the use of a Lost Revenue Adjustment Mechanism ("LRAM") that requires periodic filings and calculation of all EE savings, or it could mean decoupling utility revenues from sales for some items but not others. Implementation of an LRAM is not preferred as it provides non-symmetric recovery of lost revenues and is administratively burdensome and the filing process is often contentious. Limiting decoupling to only certain aspects can also be very complicated and does not fully eliminate the throughput incentive faced by utilities. This uncertainty surrounding the meaning of limited decoupling makes it difficult to evaluate this scenario – however, many of the factors in this scenario support a dynamic EE marketplace in New Jersey and could be included in a workable configuration of cost recovery elements (utility decoupling is a preferred approach to assure that utilities are "all-in" on promoting EE).

d. BPU Staff Scenario 4

Asset / Investment Treatment	Amortization
Recovery Period	10 Years
Lost Revenues	No Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case less 200BP
Rate Cap	3% annual increase of total customer bill

As with Scenario 1, Scenario 4 provides for no recovery of authorized revenues which are lost due to the implementation of EE. The comments regarding decoupling noted under Scenario 1 are equally applicable to Scenario 4 as well. This approach creates a perverse incentive for utilities because it threatens the ability of utilities to recover previously authorized expenses to maintain

[2] There are many forms of decoupling. For example, two gas utilities in New Jersey have a margin per customer model which establishes a baseline usage per customer and margin rates in periodic rate cases and adjusts sales for current customers to that baseline use per customer.

the safety and reliability of electric and gas distribution systems. The perverse incentive would encourage utilities to not invest in EE in order to avoid financial harm.

A structure without decoupling or lost revenue recovery also does not foster a culture of energy reduction at utilities, which is necessary for the wholesale sea change required to promote EE in New Jersey to meet the goals. As noted earlier, it is also inconsistent with the legislative intent of the CEA and the RGGI legislation.

Scenario 4 contains an arbitrary 10-year recovery period that is not directly linked to any depreciation or useful life measure. To the extent 10-years closely matches the weighted average measure life of the proposed EE portfolio it would be an appropriate recovery period; otherwise, it does not align costs with measure life and savings. Any adjustment of the WACC should also be considered in the context of the larger base rate process in which there are numerous factors considered when establishing utility rate of return. As such, this scenario would limit the utility's ability to reach CEA goals due to the financial harm caused from lack of lost revenue recovery and reduced interest in investing in substandard returns below that established in the base rate case.

2. Explanation of the Preferred Cost Recovery Scenario

The following sets forth an alternative scenario that would marshal all the State's resources toward achieving the goals of the CEA and would protect ratepayers. It would provide a strong signal to the market that investing in EE is a priority and would assure that all entities are incentivized to work toward the same singular objective – saving customers energy and money.

Asset / Investment Treatment	Amortization
Recovery Period	Weighted-Average Measure Life
Lost Revenues	Decoupling
Incentives/Penalties	TBD
Carrying Cost on Over/Under Recovery	Commercial Paper Rate
WACC	Base Rate Case
Rate Cap	No Cap

Each of the preferred cost recovery elements summarized above is explained in more detail below.

a. Asset / Investment Treatment

EE program investments should be amortized to prevent rate shocks and align costs with benefits.

b. Recovery Period

Amortization of EE program investments should occur over a period commensurate with the weighted-average useful life of the measures contained within the EE portfolio. This will properly align the recovery of costs with the realization of energy savings. Shorter recovery periods will result in larger rate shocks for customers and inequity between those saving energy and those paying for the EE measures.

c. Lost Revenues

Authorized base rate revenues should be fully decoupled as to remove the financial disincentive of reducing utility throughput and provide consumer protections against utility over recovery of revenues. This will assure that utilities are able to fund authorized base rate investments, and also insulate ratepayers from overcollection due to load growth, which could occur as a result of building electrification or electric vehicle proliferation. Full decoupling of authorized base rate revenues should be accompanied by consumer protections, such as earnings reviews, to provide additional transparency to the process and assure utilities do not earn above the authorized limits.

Decoupling is recognized as a leading mechanism to promote EE investments. As of January 2019, there are 26 states that have adopted decoupling for 64 gas utilities and 17 states that have adopted decoupling for 42 electric utilities. This is an increase from 2013, when 49 gas utilities in 20 states and 24 electric utilities in 14 states had decoupling in place.[3] In fact, even consumer friendly states and EE leaders such as New York, Massachusetts, and Rhode Island have decoupling mechanisms in place. Two utilities in New Jersey also already implement a form of decoupling in place for approximately 13 years and successfully implemented programs and protected ratepayers. This should be furthered to the balance of the State to assure all customers are benefiting from the advantages of decoupling.

d. Incentives/Penalties

As discussed in more detail below, incentives and penalties must be simple in order to provide clear signals towards preferred performance. In addition, it is vital that a 'dead-band' exist around the set goal value as to not reward or penalize fluctuations in performance out of the control of utilities. Given the challenges that face any energy efficiency programs during times of transition, the 'dead-band' should be wide enough to allow for performance toward CEA goals to be evaluated in the initial years. The exact incentive and penalty structure cannot be determined without first understanding the quantitative performance indicators that will be used to assess performance.

e. Carrying Cost on Over/Under Recovery

Carrying costs should be equal to actual utility carrying costs. At present, this is typically equal to the commercial paper rate.

f. WACC

The weighted average cost of capital is accepted cost of utility money and should be used for EE investments. Using the same WACC for EE investments and traditional utility investments puts EE on a 'level playing field' with traditional investments to help further incentivize the installation of EE in the state.

[3] Gas and Electric Decoupling. Natural Resource Defense Council. nrdc.org/resources/gas-and-electric-decoupling.

g. Rate Cap

Placing a cap on total customer bills will direct limit the ability of EE programs to achieve the goals set forth in the CEA. There are numerous benefits of EE that go beyond a simple bill or rate analysis and must be considered when evaluating EE. However, rate caps are one form of customer protection that may be included in a decoupling mechanism to limit decoupled collections.

3. Other Issues

Several key issues related to the components included in the cost recovery scenarios warrant further discussion and are highlighted below.

a. Performance Incentives

Performance incentives and penalties are one of several components of cost recovery under discussion in this stakeholder process. However, it is difficult to conduct detailed discussions about a cost recovery "package" when the details of performance incentives are undefined and unknown. That is, it is important that the "full package" be known and understood in order to judge its reasonableness. The four scenarios above contemplate general approaches to performance incentives and penalties, but the details of each approach are critical to understand the magnitude of this element of the cost recovery discussion.

The most significant undefined and unknown question related to performance incentives is related to the quantitative performance indicators ("QPIs"). The performance incentives and penalties would be issued based on the performance to the QPIs, but these are either unknown or undefined as of now. On Friday December 20, the BPU released a straw proposal for program administration, which proposed the following QPIs:

1. Annual energy savings
2. Annual demand savings
3. Lifetime energy savings
4. Lifetime of persisting demand savings
5. Utility cost test net present value of net benefits
6. Low income lifetime savings
7. Small business lifetime savings

These metrics are a good starting point, but the details are undefined. For example, to consider performance incentives, it will be necessary to understand several key questions, such as:

1. How will targets for each metric be established and updated?
2. How will performance be measured for each metric?
3. How frequently will the targets be assessed?
4. What the schedule is for recovery of rewards or penalties? Will it be in a single year or over a multiple year period?

There are also many other questions that are undefined related to the performance incentives. For example, for an adjustment to return on equity, what is the size of the adjustment? Would it be only applied to energy efficiency investments or to other authorized revenues as well? For the other two approaches (fixed dollar recovery and percentage of savings), how will the incentive pool be established? Will utilities be forecasting recovery of incentives in cost recovery mechanisms and then truing up based on actual results, or just recovering or returning dollars based on the results of the performance review.

Until the factors related to the QPIs and other targets are understood, it is premature to determine any performance incentive mechanism.

b. Rate Caps

Rate caps on total customer bills are an inexact tool that can disrupt the ability to achieve energy savings targets and reduce program performance. The CEA requires that all EE programs be cost-effective – therefore, rate caps may limit the delivery of cost-effective energy savings and carbon emissions reductions to New Jersey residents and businesses. The implementation of rate caps also produces perverse incentives for program implementers because the focus shifts from deeper energy savings to only trying to capture low cost first year savings that do not have a lasting impact. Because of this effect, rate caps will also make it difficult for utilities to meet the lifetime energy, demand, and program specific targets outlined in the proposed QPIs.

In addition, low-income programs are often the most expensive and could be severely limited as a result of capping customer rates or costs. Further, rate impacts are a key element of the minimum filing requirements, and the appropriate rate increase (if any) can and often is debated and determined in the filing process. As such, the program impacts on customer rates should be considered by the BPU in approving programs, not arbitrarily outside the context of reviewing a specific program plan.

Conclusion

Gabel Associates appreciates the opportunity to furnish these comments and provide the Board with insight into issues related to EE cost recovery.

We are happy to provide any supplementary information or answer any questions you may have regarding our comments. We look forward to continuing the open stakeholder process.

Sincerely,

Isaac Gabel-Frank
Vice President
Gabel Associates

Appendix

Comments of
Gabel Associates on the October 31, 2019
Energy Efficiency Cost Recovery Technical Meeting

November 14, 2019

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 S Clinton Ave 9th Floor
Trenton, New Jersey 08625

Comments of Gabel Associates on the Energy Efficiency ("EE") Cost Recovery Technical Meeting

Dear Secretary Camacho-Welch;

Gabel Associates, Inc. ("Gabel Associates" or "Gabel") is pleased to provide comments regarding the EE Technical Meeting focused on Cost Recovery, which occurred on October 31, 2019.

Gabel Associates is an energy, environmental and public utility consulting firm with its principal office located in Highland Park, New Jersey. For over 25 years, Gabel Associates has provided quality energy consulting services and strategic insight to its clients. Classified as a small business, the firm provides its expertise to a wide variety of clients involved in virtually every sector of the energy industry, including public and federal agencies, individual commercial and industrial end users, aggregated groups of customers, public utility commissions, power plant owners and operators, wholesale suppliers, and utilities.

Our recent work in New Jersey has included assisting several of the State's electric and natural gas utility companies develop and design cost effective energy efficiency ("EE") programs. Specifically, we have worked or are currently working on EE related activities with Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G"), Elizabethtown Gas Company ("Etown"), New Jersey Natural Gas Company ("NJNG"), and South Jersey Gas Company ("SJG").

Gabel Associates also provides extensive consulting services to customers in New Jersey including hundreds of school districts, counties, and business customers, as well as services to utility commissions and wholesale market participants. Because of the breadth of sectors where we provide our services, we have a deep and balanced sensitivity to the needs of all types of energy market participants. The principals of Gabel Associates include two individuals who served as senior managers at the BPU where they were both extensively involved in utility ratemaking, cost of service, and tariff design issues.

The Agenda for the Cost Recovery EE Technical Meeting presented thirteen (13) specific questions across three (3) general topics for discussion. Based upon the lively debate at the October 31, 2019 the Cost Recovery EE Technical Meeting, herein we address each of the Cost Recovery Stakeholder Questions.

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1. Should recovery mechanisms be the same or different for programs administered or implemented by utilities versus non-utility parties?

The establishment of the same matching recovery mechanism for utilities and non-utilities is not necessary and in fact in many cases is not possible. More important than whether recovery mechanisms match is utilizing a recovery mechanism that minimizes rate impacts to customers and optimizes program administration. A Societal Benefits Clause ("SBC") style "expensed" mechanism is rigid and cannot react or be tailored to the immediate needs of customers. One problem with the SBC is that it lacks budget certainty as the funds can be reallocated by the Governor or state legislature for other purposes. Since 2010, over $1.6 billion has been reallocated from clean energy purposes to other state budget expenses, spanning the Corzine, Christie and Murphy Administrations. Funds collected from customers for EE programs should be protected from reallocation and used for their intended purpose to ensure continuity in program offerings. Stability is needed to provide customers with bill savings opportunities while driving economic growth in New Jersey and assuring that the State makes continuous, long-term progress in reducing carbon emissions.

Additionally, fulfillment of incentives through an expense mechanism at the Board of Public Utilities ("Board") Office of Clean Energy ("OCE") are subject to delay as funds must be collected, routed through the Treasury Department, and dispersed to non-utility agencies (such as the OCE) prior to being distributed to program participants.

Utility funding and recovery is much more stable than OCE based funding and recovery. Additionally, it can provide an ongoing long-term commitment to clean energy and more accurately align costs with benefits. For example, the amortization of program costs method allows utilities to draw on access capital markets to quickly fund programs, amortize them in line with measure life and flow of benefits, and only fund those programs and incentives that are submitted through a rigorous evidentiary filing process and approved by the Board.

Another key element on the different cost recovery methods is how ratepayers' interests are protected. In utility funded programs, program review is approved by an independent party (the Board) and subject to the full range of discovery, testimony, intervention, and review in a contested proceeding. In contrast OCE program review and cost recovery is not subject to this type of rigorous review, and is instead subject to a summary presentation of program plans, an expedited "legislative style" hearing, and approval by the Board, who's own staff prepare and submit the summary presentations for approval.

2. Topic 1: Recovery of Program Costs

a. Should costs associated with efficiency program investments be expensed or amortized? If amortized, what is the appropriate amortization period, and what should the rate for the carrying costs be?

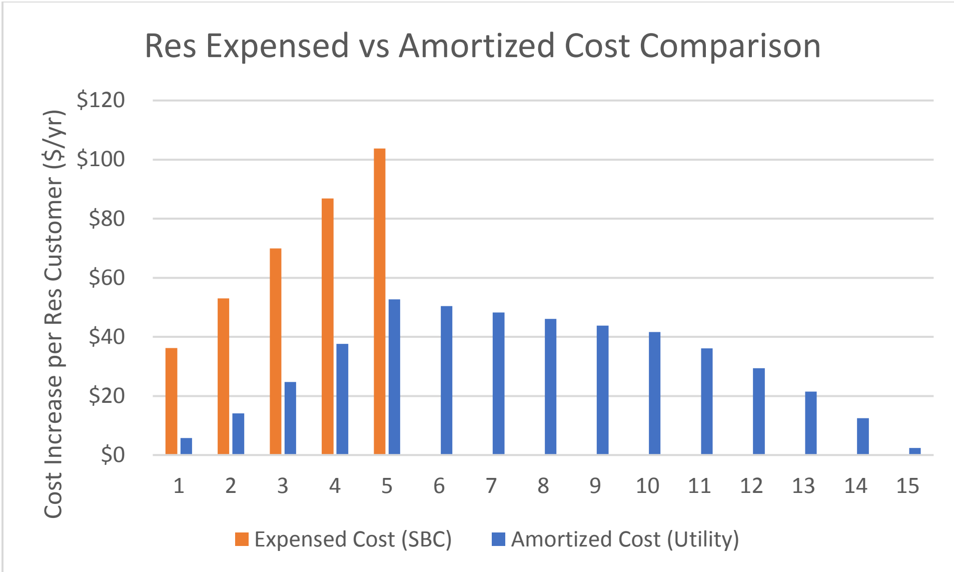
For EE to become a central component of utility planning and infrastructure development, EE program costs should be amortized over the weighted-average measure life of all the measures at the portfolio level. Amortizing over measure life is important as it not only provides intergenerational equity of costs and savings but aligns EE cost recovery with traditional utility ratemaking practices. If a utility were to invest in new lines or pipes, costs would be recovered over the useful life of those assets, often 20 to 60 years. EE investments should be treated similarly with a recognition of the length of time those EE assets will be in place. From a recovery perspective EE should be viewed by the Board as a central element of the state's investment in energy infrastructure. Recognizing that the Clean Energy Act[1] ("CEA") requires utilities to pursue EE savings targets, proper rate treatment can (along with an appropriate decoupling structure) make investment in EE as attractive to utilities as other utility infrastructure investments. With the State's ambitious clean energy goals, it is imperative to establish a structure like this to not only mandate, but actively encourage utilities to lead these transformational efforts by aligning ratemaking for EE programs with treatment similar to infrastructure investment programs.

Amortization will also reduce rate shocks and align cost recovery with program benefits and bill savings. The CEA calls for a 2.0% reduction in electric consumption and a 0.75% reduction in natural gas consumption. Regardless of the recovery mechanism, there will be rate impacts for customers to meet these objectives. Effectively managing the potentially significant spikes in electric and natural gas rates will make achieving EE policy goals more acceptable to policymakers and the public.

Amortization allows for costs to be spread over a longer period of time, therefore reducing the initial rate impacts associated with EE investments. The following graph provides a high-level example comparing the electric rate impacts of expensing costs in the year they are incurred against amortizing costs over a longer period.[2]

[1] https://www.njleg.state.nj.us/2018/Bills/PL18/17_.HTM

[2] This graphic contains numerous high-level assumptions, including 74,628,365 MWh of state electric load per the OCE Renewable Portfolio Standard ("RPS") Compliance Report, the savings targets set forth in Optimal Energy's Potential Study, a utility cost of capital rate of 7.0%, a cost of energy saved of $0.053/kWh sourced from the 90th percentile of utility administration costs contained in the ACEEE study *Does Efficiency Still Deliver the Biggest Bang for Our Buck? A Review of Cost of Saved Energy for US Electric Utilities*, a measure life of 11.1 years from the same ACEEE study, and residential consumption of 8,200 kWh per year. This was provided for theoretical illustration only and is not based upon actual real-life circumstances.



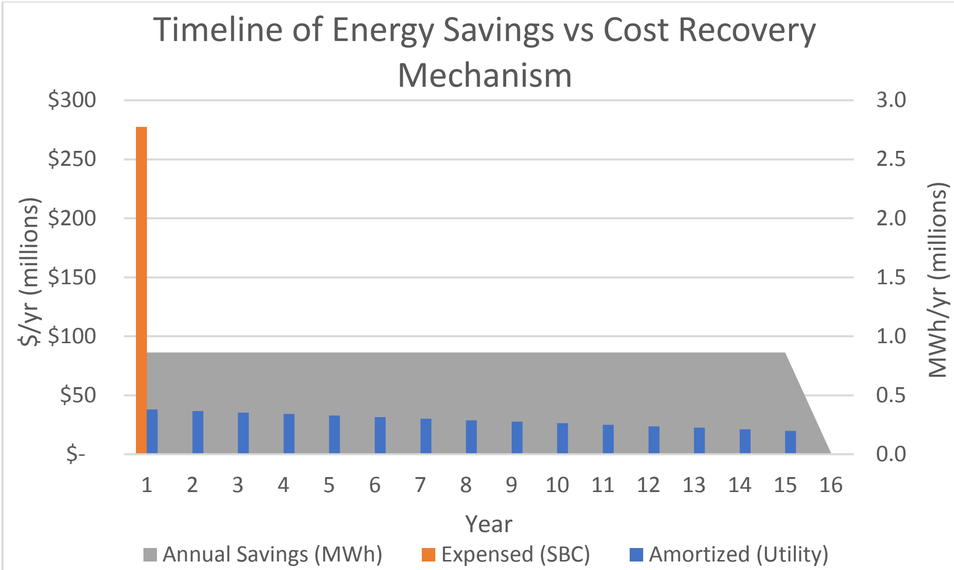
This graph illustrates what a potential five year build up to meet the goals set forth in the Optimal Energy EE Potential Study[3] (beginning at 0.75% in year one and ending at 2.15% in year five) could look like from a cost perspective. The program costs are based upon a review of program administrator costs contained in The American Council for an Energy Efficient Economy ("ACEEE") report titled: *Does Efficiency Still Deliver the Biggest Bang for Our Buck? A Review of Cost of Saved Energy for US Electric Utilities*.[4] The expensed scenario is illustrated in orange and shows that in year five costs could exceed an increase of $100 per year in electric rates for residential customers. The blue bars show the impact from amortized costs and illustrate that even in the peak year, the cost impact is roughly half that of the expensed scenario.

Please note that this is an illustrative example of residential electric costs only and is provided to offer a theoretical visual explanation of the difference in rate impacts between expensing and amortizing costs. Actual annual cost impacts are not yet known because the program portfolios needed to meet the CEA goals have yet to be developed. Commercial and industrial customers would also experience a similar relationship between expended and amortized mechanisms, with the costs per year being higher than that of residential customers.

Amortization, if implemented over the weighted-average measure life of the EE portfolios, also matches program costs with program savings. The following graphic illustrates the OCE's FY20 budget as both an expensed and amortized cost and compares those against the OCE FY20 expected lifetime savings.

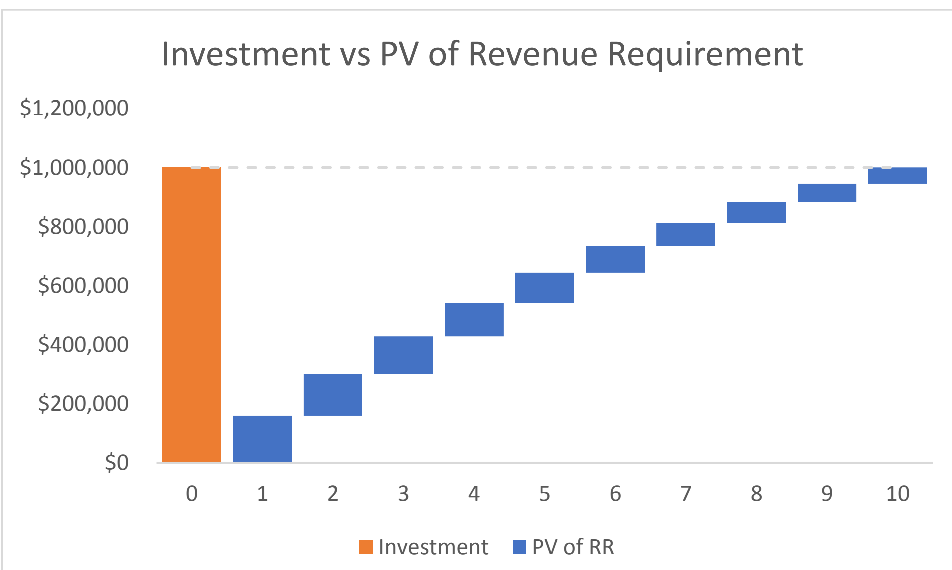
[3] https://s3.amazonaws.com/CandI/NJ+EE+Potential+Report+-+FINAL+with+App+A-H+-+5.24.19.pdf

[4] https://aceee.org/files/proceedings/2018/node_modules/pdfjs-dist-viewer-min/build/minified/web/viewer.html?file=../../../../../assets/attachments/0194_0286_000125.pdf



As seen in the graphic above, amortizing costs over time matches the costs to when the savings occur and assures that those customers receiving benefits are also paying a fair share of the costs.

EE costs should be amortized and accrue a return using a rate equal to the utility's weighted average cost of capital ("WACC") on the unamortized investment balances. The WACC is approved by the Board on a regular basis through the distribution ratemaking process and includes a comprehensive consideration of the various risks facing the utility. Further, using the WACC also means that on a present value basis, the total amortized costs equal the gross upfront investment cost if discounting at the same rate. This is illustrated in the following waterfall graphic, assuming a $1 million up-front investment compared against a high-level 10-year amortization example at a 7% return and 7% discount rate:



The orange bar represents all costs expensed in the first year. However, when amortizing over time, the payments are segmented and spread over a longer period. When accounting for the time-value of money (the Present Value, or "PV"), the return on investment costs are balanced out by the discount rate, resulting in a total payment stream that exactly equals the upfront investment amount in present value terms.[5]

b. Should costs be allocated by sector (e.g., residential, commercial, industrial)? If yes, how would you recommend doing the allocation?

Currently, EE costs are socialized across all customers. More information is required to gain a better understanding of the consequences of shifting from the current allocation method to sector specific distributions, such as an understanding of the portfolio of programs, how they are administered, and allotment of funds and achievement of savings between sectors. It should be recognized that many of the benefits of EE (such as advertising promoting EE, Demand Reduction Induced Price Effects, avoided Renewable Portfolio Standard purchases, and avoided Transmission & Distribution expenditures) are realized by all customers so it is not unfair for all customers to pay a share of costs even if such costs are for programs that are directed at other customer groups.

3. Topic 2: Potential for Recovery of Lost Revenues

a. Should there be a mechanism to recover lost revenues?

Yes, there should be a mechanism to recover lost revenues. In fact, the CEA states that:

> *Each electric public utility and gas public utility **shall** file annually with the board a petition to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, including but not limited to recovery of and on capital investment, and **the revenue impact of sales losses resulting from implementation of the energy efficiency** and peak demand reduction schedules, which **shall** be determined by the board pursuant to section 13 of P.L.2007, c.340 (C.48:3-98.1)*
> -P.L. 2018 c.17 3.e.(1) (emphasis added)

This provides that utilities shall file annually to collect lost revenues, answering the question of whether a mechanism to collect lost revenues should exist. The CEA further cites that the Board shall determine these costs based upon the *Electric, gas public utilities energy efficiency and conservation programs, investments, cost recovery; terms defined* statute which specifically allows for "rate mechanisms that decouple utility revenue from sales of electricity and gas."[6]

[5] This graphic provided is an example and for illustration only. Actual revenue requirements calculations take into account additional factors such as taxes, Allowance for Funds Used During Construction ("AFUDC"), credits, and other factors. This was provided for theoretical illustration only and is not based upon actual data for any specific utility.

[6] https://www.njleg.state.nj.us/2006/Bills/PL07/340_.PDF

In addition to the statutory language cited above, there are very strong public policy reasons why the Board should establish ratemaking mechanisms that permit recovery of lost revenues. For the State of New Jersey to achieve or exceed its EE goals, it imperative that utilities "be on the same page" as New Jersey's policy goals. If utilities lose margin by developing EE, they may direct their capital to investments that allow them the ability to earn their authorized rate of return. Recovery of lost revenues is a critical element to eliciting the cultural shift needed to move utilities into fully helping New Jersey achieve its goals. In the context of addressing climate change – a key challenge facing the State (and the planet) – the need to get utilities rowing in the same direction as New Jersey in maximizing EE becomes even more profound.

As discussed in more detail below, while there are a range of lost revenue recovery mechanisms, a properly designed decoupling approach is the fairest way to address the lost revenue issue.

b. If the Board allows for recovery of lost revenues, what should the lost revenue recovery mechanism be?

The preferred mechanism is full revenue decoupling that provides symmetrical recovery and return of under- and over-collection of distribution revenues by utilities. This already exists in New Jersey, as NJNG and SJG both have modified forms of revenue decoupling in place. In every base rate case, the Board authorizes a specific revenue requirement for each utility to cover its capital costs, expenses, and return. Decoupling assures that, regardless of sales volumes in a given year, utilities are able to recover those Board authorized revenues to pay for and maintain utility infrastructure, while limiting the ability of utilities to recover greater than the authorized revenue or return set by the Board.

Full revenue decoupling removes the link between volumetric sales and profits, eliminating any "throughput incentive". Without decoupling, utility profits are unquestionably linked to sales volumes. Therefore, a utility has a financial incentive to increase sales thereby increasing revenues. The incentive to increase sales exists regardless of any mandates to achieve CEA saving targets or other incentives or penalties that may be implemented. Decoupling severs the link between revenues and sales, removing the disincentive to decrease consumption.

Utility customers are also hedged against fluctuations in supply costs by the Basic Generation Service ("BGS") and Basic Gas Supply Service ("BGSS") mechanisms. A decoupling mechanism would provide a functional hedge for customers against fluctuations in distribution costs due to changes in sales by stabilizing total distribution collections to a fixed number.

Looking across the country there are numerous types of decoupling mechanisms; many, like the Conservation Incentive Program ("CIP") currently being implemented by NJNG and SJG, use margin per customer basis, but the mechanism can be tailored to the specific circumstances of the utility. Decoupling can and often does incorporate earnings and other types of tests to further protect ratepayers.

It is important to stress that decoupling is NOT against customer interests. A properly designed decoupling plan aligns a utility with New Jersey's goals to actively rollout EE that will reduce customer bills. Decoupling plans (including the Board approved modified version of decoupling for NJNG and SJG) also typically have specific provisions that allow the Board to periodically review the impact and results of decoupling to prevent inordinate rate impacts or excessive earnings. It's no coincidence that nearly every state at the top of the ACEEE scorecard[7] has already implemented decoupling. Included on this list are states such as New York, Vermont, Massachusetts, California, and Rhode Island which are by no means viewed as "pro-utility commissions" by analysts.

Decoupling is a superior approach to a lost revenue adjustment mechanism ("LRAM"), which is the most likely alternative if decoupling isn't approved. LRAM is a common practice that allows a utility to calculate lost revenues driven solely by EE programs. This mechanism provides recovery of lost revenues, but unlike decoupling, is not linked to any Board authorized revenue level and only focuses on lost sales from specific EE programs. LRAM generally does not protect customers from utility over-recovery when sales increase and does not eliminate the utility incentive to promote higher consumption of electricity or natural gas, which is antithetical to the state policy goals in New Jersey provided for in the CEA.

Decoupling allows everyone to work together to maximize EE savings, which is the ultimate intent of the CEA.

c. If the Board allows for recovery of lost revenues:

i. What methods should the Board employ to calculate lost revenues associated with energy savings?

Decoupling naturally accounts for all increases or reductions in sales regardless of the reason, and therefore alleviates the need to calculate lost revenues each year. Because decoupling is indifferent to the source of increase or decline in sales, it transparently allows recovery of only the Board authorized revenues, and nothing more or nothing less. Moreover, if sales increase due to economic growth, electrification of transportation, or for other reasons, this growth is likewise fully captured by decoupling, to the benefit of ratepayers. Further, decoupling mechanisms are reset after every base rate case, enabling regulators to properly reset the authorized revenue components.

As an alternative, LRAM would require annual impact evaluations for every measure and program to accurately quantify the energy savings driving lost revenue requests. This process often becomes an administrative burden for regulators and utilities because every showing of lost revenue recovery can become a prolonged litigated process over the correct energy savings estimate. Full revenue decoupling avoids this issue entirely by simply ensuring utilities only recover Board authorized revenues, regardless of the measured energy savings from EE programs.

ii. Should other factors (e.g., weather, nonprogram-related reductions) be taken into account?

Under a decoupling policy, these factors are naturally captured and will not be relevant points of contention because the mechanism trues-up utility revenues based on Board authorized revenues. If the summer is unseasonably hot and electric sales are drastically increased, the revenue captured from the additional sales would be adjusted with the decoupling mechanism. Customer consumption reductions would also be captured through a decoupling mechanism, regardless of if

[7] https://aceee.org/state-policy/scorecard

the reductions were related to the utility or statewide EE programs or some other reason (federal appliance standards for example).

Under an LRAM policy, these factors are not naturally captured and would be subject to protracted litigation. The CEA allows utilities to count non-program reductions to meet goals; therefore, it is logical that utilities would be allowed to make a showing that non-program reductions are lost revenues and should be recovered. Without decoupling this can become a burdensome process because of the contested nature of measuring non-program related reductions.

It is worth noting that the Board has a long-standing precedent of supporting weather normalization of sales with all of the State's natural gas utilities having such recovery mechanisms in place for more than two decades. Weather normalization is an equitable practice that insulates both utilities and their customers from uncontrollable variations in weather and should remain intact or be incorporated into a decoupling mechanism.

d. If the Board allows for recovery of lost revenues, should authorized return on equity be subject to adjustment based on reduced risk?

Authorized return on equity for utilities' distribution investments is established during the base rate case process. A part of the return on equity evaluation is a review of peer utilities to determine risk and the appropriate levels of return, but also includes other key drivers such as market volatility and the proper level of return necessary to attract capital to finance investment. The impact of decoupling on utility risk and return on equity will be captured in this process. Since the establishment of authorized return on equity is based upon numerous factors, it is appropriate that it continue to be determined in the rate case process.

4. Topic 3: Performance Incentives and Penalties

a. How should performance incentives be structured? How should performance penalties be structured?

The incentive and penalty structure should be simple and trued-up on an annual basis and should send a clear and measurable financial signal that encourages utilities to aggressively pursue EE results. However, without understanding the metrics against which incentives and penalties will be assessed, it's difficult to provide further specific detail on the magnitude of incentive and penalty amounts. In addition, the issue of whether the utilities or the OCE will administer programs has a significant bearing on the penalty/incentive discussion. Performance incentives and penalties should be provided in addition to, and not in lieu of, the other market design elements discussed above, including amortization of costs and decoupling.

i. Should incentives and penalties be handled as a percentage adjustment to earnings or as specific dollar amounts? Why? How?

It would be simplest and most effective to set incentives and penalties as a specific dollar amount. This could be based upon a percentage of program costs or a fixed $/unit value. Tying to a dollar value provides transparency regarding the value of incentives and penalties and sends clear signals to utilities on what the exact reward or loss is for performance.

ii. Should incentives and penalties be scalable based on performance? If so, in what manner?

Yes; however, the Board should consider using a "dead band" or collar around specific performance milestones. Performance incentives are designed to reward utilities that exceed goals; likewise, the penalties are designed to provide a disincentive to ignoring the state mandates or running programs poorly. Small variations in performance around the goal, which can occur for reasons beyond a utility's control, should not be the difference between a penalty or incentive. A "dead band" or collar would alleviate this concern.

A scalable incentive will promote utilities to strive to maximize savings rather than to simply meet goals. Because the Board wants utilities to endeavor for the greatest possible savings, it should implement a scalable incentive. Penalties should be used to assure that all utilities are fully invested in meeting the goal and should be implemented to insure a minimum level of activity.

iii. How should incentives and penalties be reconciled? Should incentives and penalties be "refunded" to ratepayers through rate reduction?

Incentives and penalties should be included as a line item in the revenue requirement calculation for each utility's EE surcharge. To the extent an incentive is awarded, it would increase the revenue requirement by the approved amount; to the extent a penalty is assessed, it would be a decrease to the revenue requirement by the assessed amount.

In that way, penalties are refunded to ratepayers. If a utility is awarded an incentive, it is indicative of the fact that the utility is exceeding its EE savings goals, meaning that its customers are achieving savings above those set by the Board.

b. If the Board establishes performance incentives and penalties, what level of total incentives and penalties is reasonable?

The incentive or penalty should send a clear and measurable financial signal that encourages utilities to aggressively pursue EE results. The EE Potential Study conducted by Optimal Energy proposed an incentive between 5% and 7.5% of the planned and approved program budgets. On a preliminary basis, this range seems reasonable. Further evaluation and determination of the appropriate level on incentives and penalties should be set in each utility filing anticipated to be submitted in the summer of 2020.

Conclusion

Gabel Associates appreciates the opportunity to furnish these comments and provide the Board with insight into issues related to EE cost recovery.

As discussed above, it is imperative that the Board align all stakeholders to meet the strong goals set forth in the CEA, and this can only be done by amortizing program costs over the weighted-average measure life of the EE portfolios, decoupling utility distribution revenues from sales volumes, and implementing incentive and penalty structures that are simple and provide clear signals to maximize energy savings.

We are happy to provide any supplementary information or answer any questions you may have regarding our comments. We look forward to continuing the open stakeholder process.

Sincerely,

Isaac Gabel-Frank
Vice President
Gabel Associates

Jersey Central Power & Light
A FirstEnergy Company

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January 3, 2020

VIA ELECTRONIC MAIL ONLY

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350
EnergyEfficiency@bpu.nj.gov

Re: Cost Recovery Scenarios
Jersey Central Power & Light Company's Comments on Cost Recovery Scenarios for Energy Efficiency Programs

Dear Secretary Camacho-Welch:

On behalf of Jersey Central Power & Light Company ("JCP&L" or the "Company"), please accept this letter as JCP&L's response to the request for comments issued by the Staff of the New Jersey Board of Public Utilities ("Board") dated November 26, 2019 and supplemented December 19, 2019. That request for comments set forth four hypothetical cost recovery scenarios that proposed different combinations of treatment for "Asset/Investment Treatment," "Recovery Period," "Lost Revenues," "Incentives/Penalties," Carrying Cost on Over/Under Recovery," "WACC," and "Rate Cap." JCP&L offers its comments on each of these categories below.

JCP&L appreciates the effort that Staff has undertaken to develop these hypothetical scenarios. The proposed scenarios recognize that the utilities' recovery of costs for running these programs is a complex matter with many factors to be taken into consideration. Accordingly, as JCP&L has indicated in its prior comments, the Company believes that each utility should be given an opportunity in its energy efficiency ("EE") and peak-demand reduction ("PDR") program filings to propose the method(s) of cost recovery that will best support its offering of programs. This approach will provide the Board an opportunity to evaluate each utility's proposal within the context of the specific details of the utility's proposed programs and will give the Board an opportunity to evaluate which method(s) of cost recovery will work best for utility-run EE and PDR programs in New Jersey.

<u>Asset/Investment Treatment, WACC, and Recovery Period</u>

<u>N.J.S.A.</u> 48:3-87.9 (the "Clean Energy Act" or "Act") clearly allows a utility to expense its costs of running EE and PDR programs. More specifically, the Clean Energy Act provides that: "Each electric public utility and gas public utility shall file annually with the board a petition to recover <u>on a full and current basis through a surcharge</u> all reasonable and prudent costs incurred

as a result of energy efficiency and peak demand reduction programs required pursuant to this section, including but not limited to recovery of and on capital investment . . ." (emphasis added). Inarguably, this statutory language permits a utility to recover its EE and PDR program costs on a "full and current basis" by expensing those costs and recovering them on a contemporary basis. Nonetheless, where a utility elects to amortize program costs over time, each utility's long-term cost of capital (*i.e.,* its weighted average cost of capital ("WACC")) is the most appropriate carrying cost.

In the event that long-term capital investment in these programs is required, the utility's WACC is the most appropriate representation of its financing costs for such investment. A utility's underlying cost of capital does not change as a result of investments being made in EE and PDR programs rather than in utility infrastructure. As detailed in JCP&L's previous comments, the assertion that EE and PDR investments are inherently less risky than other utility investments is not supported by the EE risk environment. Numerous business risks continue to exist regardless whether a utility's capital is going into EE/PDR programs or utility infrastructure, and additional risks arise specifically because of the need to implement programs successfully under the Clean Energy Act. Moreover, especially if lost revenue recovery is not allowed (in contravention to the terms of the Clean Energy Act), a utility's risk profile may actually deteriorate between rate cases as revenues decrease because of EE adoption driven by the utility's programs. As such, there is no basis to adjust the return that a utility receives on its EE and PDR investments based on the relative risk of EE/PDR investment versus infrastructure investment.

Additionally, the language of the Clean Energy Act supports that the return on any capital investment will be at a utility's WACC. N.J.S.A. 48:3-87.9(e)(4), in discussing how incentives and penalties may be implemented under the Act, provides that "[t]he adjustments made pursuant to this subsection may be made through adjustments of the electric public utility's or gas public utility's return on equity related to the energy efficiency or peak demand reduction programs only, or a specified dollar amount, reflecting the incentive structure as established in this subsection." Looking at this language, it is clear that the intent of the Clean Energy Act was to have the utility's return on any EE/PDR capital investment be the same as it is on other investments (*i.e.* at its WACC), and that such return could be adjusted for the utility's EE/PDR investments to effectuate and incentive or penalty only.

Incentives/Penalties

The cost recovery scenarios offered by Staff also include several options for the imposition of incentives or penalties based on a utility meeting or failing to meet the QPIs set for it by the Board. These options included "% of Savings (Weighted by QPI performance) / $ for Negative Benefits (Weighted by QPI Performance)," "Fixed Dollar Incentive / Fixed Dollar Penalty," and "% of return." As it has previously proposed, JCP&L encourages the Board to consider implementing a shared savings mechanism like those used in other states with successful EE programs. According to the National Conference of State Legislatures' publication "State Policies for Utility Investment in Energy Efficiency (dated April 2019), a dozen states have shared net benefits incentives. A shared savings mechanism creates a "win-win" opportunity for the utility and its customers by encouraging the utility to maximize total benefits per dollar spent, therefore maximizing benefits to both the customer and the utility. Of the options proposed in the request for comments, JCP&L understands the "% of Savings (Weighted by QPI performance) / $ for Negative Benefits (Weighted by QPI Performance)" to be most similar to such a mechanism.

Carrying Costs on Annual True-up of Over/Under Recovery

In its requests for comments, the Board also proposes different options for the interest rate applied to any under-recovery or over-recovery of program costs. As with other costs recovered through surcharges, JCP&L proposes that any under-recovery or over-recovery of program costs receive accrues interest at a rate that is consistent with the utility's actual cost of short-term borrowing; provided, however, that rates established in the annual reconciliation are designed to cure the over-recovery or under-recovery within the next twelve months. This rate should be proposed by each utility as part of its EE/PDR program plan filing and determined by the Board on case-by-case basis.

Lost Revenue Recovery

Several of the hypothetical scenarios in Staff's request for comments indicate that lost revenue recovery would not be allowed. As JCP&L has argued previously, this is plainly inconsistent with the mandate of the Clean Energy Act, which recognizes the "revenue impact of sales losses" as a category of "reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs." N.J.S.A. 48:3-87.9(e)(1). As such, any hypothetical scenario that does not allow a utility to recover the lost revenues resulting from running its programs is in violation of the Clean Energy Act.

As it pertains to the specific mechanism used by each utility to recover its "revenue impact of sales losses," JCP&L encourages the Board to allow each utility to propose as part of its program filing the mechanism that will best support its offering of EE and PDR programs. Again, this will allow stakeholders to evaluate the proposed mechanism within the context of each utility's program plan and with knowledge of the anticipated impact of the utility's proposed programs.

Rate Cap

In its request for comments, Staff proposed for the first time the concept of capping the annual rate impact of EE and PDR program costs. As an initial matter, JCP&L believes that a cap on annual rate impacts is inconsistent with the Clean Energy Act's statutory language allowing for a utility to recover its EE and PDR program expenses on a "full and current basis through a surcharge." Additionally, to the extent a cap on rate impacts is intended to prevent a utility from spending any further on EE/PDR programs in a given year, it is also inconsistent with the Clean Energy Act's mandate that the utilities design programs to meet targeted levels of EE savings on an annual basis. If such a spending cap is imposed, it will greatly impact the utility's ability to meet its targets and (as with the utility's QPIs) those targets will need to be adjusted accordingly to ensure that they are reasonable and achievable.

* * *

JCP&L thanks the Board for the opportunity to once again provide comments on this important issue. As has been expressed by many stakeholders, JCP&L believes that a cost recovery methodology that properly incentivizes each utility to run its EE and PDR programs will be key to New Jersey successfully meeting the aggressive EE goals envisioned by the Clean Energy Act. To make sure this happens, JCP&L encourages the Board not to be unnecessarily proscriptive when it comes to dictating the method(s) of cost recovery for the utilities' plans and instead recommends that the Board allow each utility to file its proposed methodology for cost and lost revenue recovery as part of its EE/PDR program plan filing.

If you have any questions about JCP&L's above comments, please do not hesitate to contact me.

Very truly yours,

Joshua R. Eckert

Joshua R. Eckert
Counsel for Jersey Central Power & Light Company

RE: NJ Clean Energy Comment: Cost Recovery Scenarios

Here is my comment.

I know I don't understand the topic fully, but I want to express that the investment, lost revenue, incentives and rate caps should be tied towards the utilities engagement with the public and especially NJ High Schools (HS) and Colleges in terms of competitions and pilot projects starting in 2020 through till 2025. Especially in enabling the hydrogen energy economy.

The greater investment a utility enables and complete with schools as the engine, the increased write offs and incentives. HS students are the best way for rapidly engaging the public and creating an awareness of and changing public behavior towards more efficient practices.

The current infrastructure grid is not capable of electrifying electric charging gas stations. Instead of electrification as a solution, engage HS and college students to look towards local hydrogen generated/storage/distribution as a method for offsetting electrification requirements. The more competitions that a utility sponsors from 2020 until 2024, the greater the incentives they earn. A utility that does nothing ends up paying fees by end of 2020 every year, that increase every year.

Rate impact caps needs to be stabilized no greater than 2% with an objective of bring rates down after 2025.

There are many companies in the US plus globally, that would eagerly invest in the hydrogen implementation. For example, Nikola Truck has 14 billion and is looking to enable locally generated hydrogen from clean energy at their hydrogen gas stations. They plan on rolling out stations in 2020, why not build incentives for utilities to enable this? Electric charging can be easily achieved from hydrogen storage without the cost of electrification to enable the charging.

1. Asset/Investment Treatment
2. Potential for lost revenue: should be a formula that incorporates engagement with public, transformation of infrastructure grid and reduction in fossil fuel energy generation and usage.
3. Incentive and Penalty
    a. More school competitions, studies and pilots more incentives per year
    b. No school competitions, studies, or pilots, increasing fees every year starting in 2020.
4. Rate impact caps – must be capped at 2% for first 5 years then reduced.
5. Uniformity of cost recovery mechanism – cost recovery will vary based on business model adjustment. NJCleanEnergy can set a structure, but needs to be flexible to enable utilities to explore different business models for achieving the maximum energy efficiency and reduction of usage.

If utilities use NJ Schools and start competitions, studies and pilots around hydrogen enabled microgrids, there is a significant possibility for dramatically reducing natural gas and oil both residentially and in electric generation. Could use neighborhood transformer as the boundary point for a hydrogen microgrid.

Did you know:
UK is successfully integrating hydrogen into natural gas pipelines now.
https://fuelcellsworks.com/news/hydeploy-uk-gas-grid-injection-of-hydrogen-in-full-operation/

There are 3 new methods for generating hydrogen from water (that I am aware of so far):

1. Photo-electric-chemical www.hypersolar.com
2. Nano Nickel coated electrodes in hydrolysis https://scitechdaily.com/new-way-to-make-hydrogen-energy-out-of-water-much-more-cheaply/
3. Hydrogen generation from water via electromagnetic resonance http://h2energynow.com/

Governor Murphy and Commissioner McCabe signed a multistate zero emission initiative?
https://ww2.arb.ca.gov/sites/default/files/2019-12/Statement%20of%20Intent_ZEVI.pdf This initiative includes hydrogen fuel-cell vehicles (FCEV).

The more a utility invests into NJ schools for research, competitions, studies and pilots on local-generated hydrogen as a building block for microgrids, the increased incentives and increased 3 year cap (up to 3%).

I don't know the right scale for caps and write-offs that would make sense. I would suggest using NJEDA to build those models for mitigating cost increases, exploring methods to encourage hydrogen technology companies to work with utilities and while investing in new hydrogen energy economy.

It is time to start rethinking how clean energy is enabled and utilizing all the massive investments many countries and companies are doing between 2020 and 2025. Connecting NJ utilities with these resources will enable a more rapid clean energy attainment. Setting incentives for utilities to engage NJ schools increases the likelihood for success and early rapid adoption.

I appreciate your consideration.

Kirk Frost

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PHIL MURPHY
Governor

SHEILA OLIVER
Lt. Governor

STEFANIE A. BRAND
Director

January 3, 2020

By Hand Delivery and Electronic Mail
Honorable Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: Clean Energy Act New Jersey Energy Efficiency Transition Stakeholder Process Energy Efficiency Stakeholder Meeting – Cost Recovery
BPU Docket No.: Undocketed Matter

Dear Secretary Camacho-Welch:

Please accept for filing the enclosed original and ten (10) copies of comments being submitted on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel") in connection with the above-referenced matter and the Energy Efficiency Technical Working Group Meeting II for Cost Recovery held on December 13, 2019. Copies of Rate Counsel's comments are being provided to all parties on the service list by electronic mail and hard copies will be provided upon request to our office.

We are enclosing one additional copy of the comments. **Please stamp and date the extra copy as "filed" and return to our courier.**

Thank you for our consideration and attention to this matter.

Respectfully submitted,

STEFANIE A. BRAND
Director, Division of Rate Counsel

By: Maura Caroselli, Esq.
Assistant Deputy Rate Counsel

Enclosure

cc: EnergyEfficiency@bpu.nj.gov
Paul E. Flanagan, BPU
Sara Bluhm, BPU
Kelly Mooij, BPU
Jim Ferris, BPU
Mike Hornsby, BPU
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James Boyd, BPU
Pamela Owen, ASC, DAG

Clean Energy Act
New Jersey Energy Efficiency Transition
Stakeholder Process
Energy Efficiency Stakeholder Meeting – Cost Recovery

BPU Docket No.: Undocketed Matter

Comments of the Division of Rate Counsel

January 3, 2020

Introduction

As part of the process to implement the Clean Energy Act[1], the Staff ("Staff") of the Board of Public Utilities ("Board", "BPU") convened a Stakeholder Meeting on December 13, 2019 and invited stakeholders to comment on the subject of cost recovery for energy efficiency ("EE") programs in New Jersey.

The within comments are being submitted by the New Jersey Division of Rate Counsel ("Rate Counsel") pursuant to the Notice circulated on November 27, 2019 ("Notice"), and the subsequent Request for Comments dated December 19, 2019 ("RFC") which included four hypothetical cost recovery scenarios intended to further engage discussion by stakeholders. In comments filed on November 14, 2019, Rate Counsel has already expressed its position on the various components outlined in the four scenarios.[2]

Most importantly, ratepayers should not bear the greater risk and burden of energy efficient programs implemented by utility companies pursuant to the CEA. Without a balanced cost recovery structure, customers will not see lower utility bills despite their conservation

[1] P.L. 2018, c. 16 (C.48:3-87.3-87.7) ("Clean Energy Act" or "CEA").
[2] See Rate Counsel's earlier comments, dated November 14, 2019.

efforts. As a result, customer support for energy efficiency programs could erode. The Board must provide a framework for a balanced and fair approach to cost recovery pursuant to the CEA where utilities can be fairly compensated while lowering energy costs for ratepayers.

In the EE context, certain stakeholders' opposition to customer protections like rate caps should give great pause to the Board since rate caps may be one of the most effective safeguards against upward rate spirals. Indeed, given the scope of the savings from the programs a rate cap should not be problematic at all. If EE cost recovery includes earning a recovery on energy efficiency programs at the utility's full weighted average cost of capital, carrying costs set at an unreasonable level, full decoupling, no rate cap, payments for incentives, and amortized recovery at the weighted-life of assets, ratepayers will be forced to provide a windfall to utilities for implementing EE programs which were originally intended to save energy and lower bills. It is simply not necessary to compensate the utilities under every cost-recovery component in order to achieve the goals of the CEA.

The combination of various components in the four scenarios circulated by Staff and addressed below do not inherently change Rate Counsel's earlier position on those issues, yet Rate Counsel will address each scenario separately below. It should be noted that Rate Counsel's feedback on these scenarios is not final since there are many factors at work when a utility program is developed and presented in a filing before the Board. The "right" EE cost recovery mechanisms cannot be summarized into a fixed equation. The appropriate cost recovery mechanisms may shift depending on, for example, the features of a utility energy efficiency program, specific results of a benefit-cost analysis, the size of the company, a specific utility's capital structure, and even the utility's history of energy efficiency in New Jersey. There is simply no one-size-fits-all solution to cost recovery. Therefore, Rate Counsel urges the

Board to take a balanced approach to EE cost recovery that provides protections for ratepayers and maintains the ability to be flexible in response to specifically proposed programs.

Scenarios for Stakeholder Comment

SCENARIO 1

Asset / Investment Treatment	Expense
Recovery Period	Annual
Lost Revenues	No Decoupling
Incentives/Penalties	% of Savings (Weighted by QPI Performance) / $ for Negative Benefits[3] (Weighted by QPI Performance)
Carrying Cost on Over/Under Recovery	T-Bill
WACC	None
Rate Cap	2% annual increase of total customer bill

The combination of components in Scenario 1 are least favorable for the utility.

Investment Treatment/Recovery Period

Costs associated with EE program investments should not be expensed. These costs should be amortized, as these programs are expected to benefit more than one period. The amortization period should be evaluated in the context of projected rate impacts. Annual

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[3] Dollars ($) for Negative Benefits represents a dollar for dollar penalty for net negative benefits. Under this scenario, if after Measurement and Verification a utility's energy efficiency programs fail the benefit-cost test developed by the BPU, a utility would be subject to a penalty equal to the amount by which the utility fails the test. This penalty would be weighted by Quantitative Performance Indicator performance.

expensing may provide a benefit to the utility, however, annual program costs may be excessive and harmful to ratepayers.

Lost Revenue Recovery

Rate Counsel has previously expressed its preference for no decoupling, particularly if a utility is able to earn a return on its energy efficiency investments and earn energy efficiency incentives. While Scenario 1 does not allow a utility to earn a return on its EE program investments it does provide for incentives and a return on carrying costs. As such, Rate Counsel would find this scenario with no decoupling preferable.

Incentives and Penalties

The incentives and penalties outlined in Scenario 1 are not clear on how exactly they will be "weighted" by the Quantitative Performance Indicator ("QPI") performance. Is this weighting on a total program basis or by the performance at each individual component of the program?[4] How will these weighted amounts be determined? Are they the same for each utility or will they be different? Further, the manner in which the penalty is defined in this Scenario could be harmful for a utility particularly if a utility significantly fails its CBA. Also a smaller utility that fails by a small margin may also be more significantly and negatively impacted. For instance, a $15 million failure would impact a smaller utility differently than a larger utility.

Interest on Carrying Costs

Rate Counsel would prefer not to allow interest on carrying costs. As previously provided in comments, however, if interest on carrying costs is allowed then such a rate should be set at the rate of a 2-year Treasury Bill, an interest rate comparable to those held on ratepayer deposits, another comparable short term rate that usually follows the London Inter-bank Offered

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[4] See N.J.S.A. 48:3-87.9(c).

Rate ("LIBOR") or commercial paper rates, or some other transparent and commonly reported rate (a rate similar to the societal benefits charge fund).

WACC

Rate Counsel believes that a utility should not be allowed to earn a return on its EE investments. New Jersey is unique in that it currently allows a return on EE investments, being only one of four states in the U.S. that allow for this incentive. Eliminating the opportunity for a utility to earn a return on EE investments would be in line with current regulatory practices in the U.S.

Rate Cap

Rate Counsel is supportive of rate caps in the context of multiple clauses not tied directly to providing service to an individual customer. A rate cap is a crucial ratepayer protection since it limits the impact of a utility's capital expenditures on household, business, or industrial customers' utility bills to some pre-defined percent. The part of the utility's revenue requirement that is above the fixed percentage cap should either be deferred to a later period or treated in a fashion consistent with traditional ratemaking practices. A rate cap on base rates is preferable to a total bill rate cap. A two percent rate cap on base rates appears reasonable from a ratepayer prospective and would prevent rates from spiraling upward.

SCENARIO 2

Asset / Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Full Decoupling
Incentives/Penalties	Fixed Dollar Incentive/ Fixed Dollar Penalty (Thresholds related to QPI performance)

Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case
Rate Cap	No Cap

The combination of components in Scenario 2 are most favorable for the utility. Ratepayers will be overpaying for EE programs under this scenario as it awards the utility multiple benefits all at the cost of ratepayers. If the utilities are allowed to earn a return on EE investments through a surcharge as they do now, be awarded incentives, and also recover alleged lost revenues through decoupling, ratepayers will carry all the risk and burden and potentially overpay for EE programs and measures.

Investment Treatment/Recovery Period

As previously stated, Rate Counsel prefers amortization over expensing and the amortization period should be evaluated in the context of projected rate impacts.

Lost Revenue Recovery

Rate Counsel is not supportive of full decoupling, particularly when combined with a return on EE investments, amortization, EE incentives, and interest on carrying costs. It is also important to note that there is no clear definition of the "Full Decoupling" recovery mechanism stated in this scenario. Decoupling has manifested in various forms in different states where some form of lost revenue recovery is permitted. Notwithstanding Rate Counsel's detailed comments below on full decoupling in its general form, if provided with more details about the specific full decoupling mechanism envisioned in this scenario, Rate Counsel could provide additional comments on why specific aspects of a full decoupling do not benefit ratepayers. In general, Rate Counsel's position is that full decoupling is a more robust and blunt lost revenue recovery mechanism than that envisioned in the CEA.

The CEA states that each electric public utility and gas public utility shall file an annual petition with the Board to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency and peak demand reduction programs required by the Clean Energy Act, pursuant to N.J.S.A. 48:3-98.1, including but not limited to (1) recovery of and on capital investment and (2) recovery of the revenue impact of sales losses resulting from implementation of these programs.[5] The cost recovery calculation in the annual filing should also include any performance incentives or penalties, as determined by the Board through an accounting mechanism established pursuant to N.J.S.A. 48:3-98.1 and N.J.S.A. 48:3-87.9(e)(2).

While the CEA allows the utility to request recovery of lost revenues, it does not guarantee recovery. Additionally, the CEA provides that such recovery would only occur if costs are found to be reasonable and prudent. A decoupling mechanism allows cost recovery regardless of cause or reason and there is no also prudency review evaluating the reasoning for the adjustment(s) or if lost revenues were prudently incurred as a result of effective energy efficiency programs or measures or demand reduction programs.

The CEA specifically provides that utilities can request recovery of costs including revenues associated with the "sales losses resulting from implementation of the energy efficiency and peak demand reductions" that are mandated under the legislation.[6] The CEA's ratemaking treatment of lost revenues, therefore, is much more specific than a decoupling mechanism. A full decoupling mechanism allows recovery of all revenue losses associated with any change in

[5] N.J.S.A. 48:3-87.9(e)(1).
[6] N.J.S.A. 48:3-87.9 (e)(1), emphasis added.

sales, regardless of reason: weather; electric and natural gas commodity price changes; economic conditions; exogenous shocks; efficiency changes; technological change, to name a few. The CEA, however, is much more specific and calibrated, only allowing utilities to ask for lost base revenues that are shown to be resulting from their respective energy efficiency activities. This language limits the recovery of lost base revenues to those that are directly attributable to the utility's activities. A revenue decoupling mechanism shifts a large part of the revenue losses from efficiency activities away from participants and onto non-participating customers with little benefit. Rate Counsel is not supportive of a full decoupling mechanism under any scenario.

Incentives and Penalties

The incentives and penalties outlined in Scenario 2, again, are not clear on how exactly these fixed amounts will be set or determined. However, Rate Counsel supports the use of an incentive/penalty mechanism in the form of an adjustment to the applicable ROE. Here, in Scenario 2 with full decoupling, the applicable ROE would need to be adjusted to a lower baseline level to reflect the reduced risk of lost revenue inherent with decoupling. The incentive/penalty should take the form of an upward or downward adjustment to this baseline ROE. (See additional comments under Scenario 3)

Interest on Carrying Costs

See Comments under Scenario 1 above. Interest on carrying costs set at the level of the 2-year Treasury bill plus 60 basis points is similar to the interest allowed on other clause-type recovery mechanisms such as the Societal Benefits Charge.

WACC

See comments under Scenario 1. Rate Counsel would prefer that a utility not be allowed to earn a return on its EE investments. Should a utility be allowed to earn a return on its EE investment then that return should be set at a rate lower than the utility's overall base rate return since inclusion of a return on EE investments is yet another incentive for the utility funded by ratepayers and, furthermore, it is subject to less risk through a clause-type recovery mechanism.

Rate Cap

Rate Counsel is not supportive of "no rate cap" structure. See comments under Scenario 1 above.

SCENARIO 3

Asset / Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Limited Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill
WACC	Base Rate Case
Rate Cap	No Cap

The combination of components under Scenario 3 primarily benefit the utility, similar to Scenario 2. Ratepayers are only slightly advantaged when compared to Scenario 2 in that Scenario 3 provides for limited decoupling but otherwise there is very little, if any benefit to ratepayers under this scenario. Ratepayers will be overpaying for EE programs under Scenario 3. The Board as well as stakeholders need to be cognizant of this as ratepayers cannot continue to fund and assume all of the risk without any corresponding benefit or reward. As more and more costs are pushed onto ratepayers their investments in EE measures become less financially viable which is a "lose-lose" situation for all stakeholders, particularly when the utility has a statutory mandate to reduce usage and peak demand.

Investment Treatment/Recovery Period

Rate Counsel is supportive of amortization and the amortization period should be evaluated in the context of projected rate impacts. See comments under Scenario 1 and Scenario 2.

Lost Revenue Recovery

See comments under Scenario 1 and Scenario 2. Overall, Rate Counsel is not supportive of full decoupling, particularly when combined with a return on EE investments, amortization, EE incentives, and interest on carrying costs. Yet, if the Board were to allow for decoupling, a limited decoupling mechanism would likely be preferable; however, such a mechanism should not be allowed when combined with all of the incentives outlined in Scenario 3. Additionally, it is important to note that the Board's presentation of a "Limited Decoupling" mechanism is not defined in this scenario. A limited form of decoupling would likely be marginally more preferable to full decoupling. More details of what a "Limited Decoupling" mechanism would entail are necessary in order for Rate Counsel to provide reasoned comments on how each feature of the mechanism would affect ratepayers.

There must be a balance between ratepayer interests and those of the utility. Scenario 3, similar to Scenario 2, provides a utility with a "we win and ratepayers lose" approach to incentive/penalty mechanisms. Scenario 3 provides multiple incentives for the utility including limited decoupling, performance incentives, interest on carrying costs, full rate case WACC, and no rate caps on recovery. Ratepayers are only given an undefined "limited decoupling" mechanism, as opposed to the alternative of full decoupling as a "benefit." Rate Counsel is not supportive of limited decoupling under Scenario 3, since under this scenario the Company is afforded multiple benefits and incentives which unreasonably burden ratepayers. In sum, ratepayers will assume all of the risk without any commensurate benefit in return.

Incentives and Penalties

As provided in Rate Counsel's previous comments filed on November 14, 2019 and set forth in Scenario 2 above, Rate Counsel's position is that incentives should be in the form of an adjustment to a lower baseline ROE.

Interest on Carrying Costs

See Comments under Scenario 1 above. If carrying costs are allowed, interest on carrying costs should be set at the level of the 2-year Treasury Bill plus 60 basis points since this is similar to the interest allowed on the Societal Benefits Charge.

WACC

See comments under Scenario 1. Rate Counsel would prefer that a utility not be allowed to earn a return on its EE investments. Should a utility be allowed to earn a return on its EE investment, then that return should be set at a rate lower than the utility's overall base rate of return since in inclusion of a return on EE investments is yet another incentive for the utility funded by ratepayers. In the past, the Board has approved a number of settlements for accelerated pipeline replacement programs for natural gas utilities which set a return on those program investments at a level lower than the utility's overall rate of return awarded through a base rate proceeding.

Rate Cap

Rate Counsel is not supportive of a "no rate cap" structure. See comments under Scenario 1.

SCENARIO 4

Asset / Investment Treatment	Amortization
Recovery Period	10 Years
Lost Revenues	No Decoupling
Incentives/Penalties	% of return (Weighted by QPI performance)
Carrying Cost on Over/Under Recovery	2 Year T-Bill + 60bps
WACC	Base Rate Case less 200BP
Rate Cap	3% annual increase of total customer bill

Investment Treatment/Recovery Period

Rate Counsel is supportive of amortization. See comments under Scenarios 1 – 3.

Lost Revenue Recovery

Rate Counsel is supportive of no decoupling. See comments under Scenarios 1 – 3.

Incentives and Penalties

As noted in Rate Counsel's comments filed on November 14, 2019 and in Scenarios 2 and 3 above, Rate Counsel supports the use of an incentive/penalty in the form of an adjustment to a baseline ROE. In other words, where a utility is permitted to earn a return on EE-related additions to its rate base and where a baseline ROE is lower than its base rate case ROE to reflect the reduced risk to the utility of a clause-type recovery of its EE expenditures.

Interest on Carrying Costs

See Comments under Scenario 1 above. If carrying costs are allowed, interest on carrying costs should be set at the level of the 2-year Treasury Bill plus 60 basis points since it is similar to the interest allowed on the Societal Benefits Charge.

WACC

See comments under Scenario 1 – 3 above. Rate Counsel would prefer that a utility not be allowed to earn a return on its EE investments. Should a utility be allowed to earn a return on its EE investment, that return should be set at a rate lower than the utility's overall base rate return since inclusion of a return on EE investments is yet another incentive for the utility funded by ratepayers. Therefore, Rate Counsel would generally be supportive of a WACC adjustments as that outlined in Scenario 4.

Rate Cap

Rate Counsel is supportive of rate cap protection for ratepayers. However, Rate Counsel would prefer a lower rate cap such as 1 or 2 percent applied to the base rate portion of the customer's bill. See comments under Scenario 1.

January 3, 2019

Re: Energy Efficiency – Cost Recovery Comments

To: Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 S Clinton Ave 9th Floor
Trenton, New Jersey 08625

Dear Secretary Camacho-Welch,

In the matter referred to above, the New Jersey Energy Coalition submits the following consensus comments on energy efficiency regarding cost recovery.

The New Jersey Energy Coalition is a broad-based advocacy organization. The mission of the NJ Energy Coalition is to generate public support for the production, delivery, and use of affordable, clean, reliable, American energy to help meet New Jersey's growing energy needs. Our members include investor owned energy companies who deliver the energy needed for New Jersey and its' economy.

New Jersey's energy industry is one of the oldest and most significant in the world. Each company and territory in New Jersey is unique. Over time bonding and issuances of securities have been done differently by each company, with oversite by the regulator. This process has worked in favor of the rate payer to enjoy a better life than those before them. A broader approach for energy efficiency standards would fit best with the goals of 2 percent for the EDCs and .75 percent for GDCs. Establishing something similar to the infrastructure investment rule, which gives guidance but does not impose limitations would work best.

The next generation of energy efficiency for New Jersey is best served with a utility-managed programs with a reasonable return on equity along with a decoupling mechanism, if needed, to ensure proper cost recovery. This does not mean removing the regulators from their job, only help to enhance New Jersey's opportunity to reach its goals. Given the recent FERC Order[i] to PJM there are concerns now of state-run programs will be negatively impacted from this order. Shifting these types of programs to the companies to run with proper oversight from the BPU would help to ensure energy efficiency programs are sustainable.

1. Asset investment treatment –

    For the needs of amortization vs expense of the investment we emphasize the need to take a look at this on an individual company basis. Each company has its own unique needs and there for needs to be treated with that respect. The investments needed for energy efficiency are no easy tasks and will require investments from the companies onto the systems. Investments have been made differently over time for each company and therefore treatment between amortization and expense should be left up to individual company filings.

2. Incentives –

   Incentives need to be a positive one. If New Jersey is serious about energy efficiency and wants the companies and the public to participate, incentives are the way to go. Any penalty placed on a company is felt by everyone in the economy. Investors will react, as will rate payers who may be burden by the penalties. To truly spur investments, a genuine incentive program for the companies must be in place and give everyone the opportunity to benefit from energy efficiency. Even more so incentives can be passed to rate payers there by adding to the energy efficiency dividend.

3. Lost revenue –

   Lost revenue will need to be addressed, since rates are based on volumetric sales in NJ. Without a proper mechanism for lost revenue to be recovered, lending institutes and investors may take a negative view of New Jersey, making it more difficult for investments in the rest of the economy. There is a direct connection between the energy industry and the economy and once its upset by negative government intervention it could take a long time to recover from poor decisions.

   With lost revenue, one way to deal with this is to allow the companies to apply for decoupling as it makes sense for their company. As energy consumption goes down this means less of sales and therefore less funding for jobs and infrastructure directly impacting the economy. New Jersey cannot afford to loss recession proof jobs.

   The Center for Climate and Energy Solutions[ii] shows there are 31 states that have a form of either decoupling or a lost revenue mechanism. Each state has its own way and interpretation to fit the needs of the companies and the state. For energy efficiency to be successful a mechanism for both electric and gas would be needed based on the individual electric and gas companies.

4. Cap –

   If a cap is placed on any aspect of energy efficiency then there will be a cap on investment and a cap on energy efficiency opportunities. This will lead to lost opportunity and will directly impede the 2018 Clean Energy Act. Additionally, placing a cap would take away the Board's inherent rights bestowed upon it. If caps are imposed what happens if a company does not reach the targets assigned? Who is responsible for the possible penalties if arbitrary caps are imposed on the companies not allowing them to make the investments needed for their systems to reach the goals set forth in the law?

5. Cost Recovery Mechanism –

Uniformity of the mechanism for energy efficiency is difficult to justify. A mechanism for all of New Jersey does not work in any aspect given the different regions and the different needs of those regions. Since 2006 New Jersey has had the Conservation Incentive Program (CIP), a modified form of decoupling, which has proven companies can successfully embrace strategies that help reduce customer energy usage and advance public policy. This mechanism proves the ability to decouple is capable of working, should a company determine it wants to do so. Decoupling when done correctly helps rate payers save money. This is part of the energy efficiency dividend.

In 2007 New York's Public Service Commission issued an ordered-on decoupling with case numbers 03-E-0640 and 06-G-0746[iii]. New York worked with the individual companies to ensure lost revenue was properly addressed. This is an example that decoupling mechanisms need to fit the individual companies not the other way around.

If a mechanism is established it needs to be broad in the sense that it allows the companies to make filings on an individual utility basis. If factors are to be taken into account the most important thing is that there is a difference across New Jersey. An example of an issue is rate payer who comes from Mercer County and has a coastal property in Cape May County is only shifting their usage but the assets for both areas still need to be paid for to ensure reliable delivery but because the assets have been bought at different times and investments are made differently means they will depreciate differently. What needs to be taken into consideration is that each company goes out for bonding and investment in their own way, just as we all do for our own personal lives. Those assets still depreciate and they also need support to continue to operate at optimal levels.

Conclusion:

The Clean Energy Act of 2018 called for reduction in energy usage for both electric and gas sectors. Dramatic reduction like this will mean a new mechanism for recover will need to be add into the tariffs. The new mechanism will need to allow the companies to recover properly, allow the companies to apply based on the system needs, allow the companies to maintain a proper return on equity while producing good paying jobs, reducing emissions, and helping to build a more sustainable way of life.

Respectfully,

Erick Ford
Executive Director,

[i] https://www.ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf

[ii] https://www.c2es.org/document/decoupling-policies/

[iii] http://www3.dps.ny.gov/W/PSCWeb.nsf/All/A0227F4885E1769485257687006F38C2?OpenDocument

New Jersey Energy Efficiency Transition

Energy Efficiency Technical Working Group—Cost Recovery

Comments of the New Jersey Large Energy Users Coalition

The New Jersey Large Energy Users Coalition appreciates the opportunity to provide these comments regarding the scenarios for utility cost recovery in connection with energy efficiency initiatives conducted pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.3 *et seq*.

As a preliminary matter, NJLEUC observes that energy efficiency has long been viewed as the most cost-effective mechanism available to reduce energy usage, peak demand and greenhouse gas emissions. In fact, energy efficiency projects may often be pursued on a self-funding basis, with the cost of energy efficiency measures fully offset by the savings derived from their use, enabling such projects to be pursued at low cost.

The Energy Savings Improvement Programs ("ESIP") Law provides a good example of how energy efficiency projects may be implemented on a self-funding basis, in this instance without ratepayer impact. The ESIP Law authorizes certain governmental entities to finance energy savings programs through long term lease purchase agreements on a budget neutral, fully self-funded basis based on the energy savings derived from the energy conservation measures implemented in ESIP projects, without requirement of up-front capital contributions by the contracting entities. The ESIP Law also provides an option for the projected savings to be guaranteed by the contracted energy service company, which is obligated to reimburse the governmental entity for all projected savings that are not actually realized, thereby eliminating any financial risk associated with an ESIP project.

More generally, well-designed programs, which have been determined through use of appropriate evaluation metrics and market research to achieve program goals in a cost-effective manner, using properly calibrated customer incentives and controlled administrative costs, should provide maximum energy and cost savings without unduly burdening ratepayers. In this regard, investments in energy efficiency by commercial and industrial customers, supported by incentives provided by the Office of Clean Energy, have long been recognized to provide the biggest "bang" for the energy efficiency buck, producing returns of up to eleven times the capital invested in these projects.

Given the beneficial results obtained in these circumstances, the Board should approach the current exercise with the view that utility energy efficiency programs should likewise be delivered in a cost-effective manner, including administrative costs, and that the utilities should be fairly, but not overly compensated for their efforts, including the potential to be compensated for provable lost revenues in appropriate circumstances. However, the Board should reject the invitation by some to provide multiple layers of compensation and other regulatory bells and whistles—such as the combination of accelerated cost recovery, WACC, a non-risk adjusted ROE, and rate decoupling--that are unwarranted and excessive, and have the clear potential to more than erase any cost reduction benefits that may otherwise be derived from prudent investments in energy efficiency measures.

In these comments, NJLEUC does not directly address the four hypothetical scenarios that have been presented by staff, but instead addresses the issues raised in a generic fashion that we view as applicable to each scenario.

1. Asset/Investment Treatment

Expensing vs. Amortizing

Given the size of many recent utility investment programs, as reflected in the two scenarios initially presented, expensing and recovering costs in the year in which they were incurred would likely not be an acceptable option as it would create the potential for significant rate shock. In most instances, the use of amortization to spread the cost recovery over a period of years would be the preferred option. Depending on the size of a particular utility program, the amortization period could either be coincident with the duration of the program or for an alternative period of time that properly balances concerns regarding the potential for rate shock and intergenerational cost recovery. As a general proposition, the amortization period for a given utility program should not be permitted to exceed ten years.

With regard to the interest rate to be permitted for carrying costs, because cost recovery of approved program costs is contemplated by the Clean Energy Act, the carrying charges should reflect a low/no risk rate of return and should not exceed the utility's cost of debt. The potential for the utility to annually recover lost revenues caused by its energy efficiency programs further reduces any risk associated with these programs and provides additional justification for low carrying charges.

2. Potential for Lost Revenues

The Clean Energy Act authorizes electric and gas utilities to petition the Board to recover the reasonable and prudent costs incurred in connection with utility energy efficiency programs and the "revenue impact of sales losses *resulting from* implementation of the energy efficiency and peak demand reduction schedules" set forth in the Act. N.J.S.A. 48:3-87.9 (e) (emphasis supplied). The clear language of the Act therefore underscores that it is the utilities' burden to demonstrate in their annual petitions to the Board that any claimed lost sales revenues "result from"—e.g. are directly attributable to--the utilities' energy efficiency and peak demand initiatives, and not to exogenous factors unrelated to these initiatives.

Further, lost revenues should be assessed on a "net" basis that takes into account any additional revenues earned by the utilities that are made possible by their energy efficiency investments. That is, if a utility can show its total revenues for a specific customer class of service have declined due to energy efficiency and peak demand programs for the customer class, it can be deemed to have compensable lost sales revenues. If these energy efficiency programs afford the utilities an opportunity to earn additional revenues from, among others, the sale of energy efficient products and services and sales of "freed up" incremental capacity and wholesale energy--as well as benefiting from accelerated cost recovery, and/or a return of and on their energy efficiency investments calculated at the utilities' weighted average cost of capital or existing return on equity--these additional revenues properly should offset any revenues arguably "lost" due to the utilities' energy efficiency investments. In such circumstances, a threshold question must be whether there are actual lost revenues to recover, because these additional revenue streams may offset the revenues that might otherwise be deemed "lost". In a word, permitting recovery of "lost revenues" where the energy efficiency programs provide utilities with additional revenue streams or generous cost recovery mechanisms could enable the utilities to inappropriately double recover their costs or earn excessive returns of and on their investments.

As an alternative to focusing on revenues, the Board could instead consider a compensation regime that more closely correlates to the effectiveness of energy efficiency programs by class of service. Measuring program effectiveness should focus on the extent to which the programs fulfill their purpose to reduce energy consumption and peak demand. For example, the Board could apply a metric that measures actual market penetration (e.g. how many energy efficient lighting fixtures, variable speed motors and other products were installed under a utility program) as an indication of program effectiveness. Such an approach would be reminiscent of the old Standard Offer Program, which provided compensation to utilities for reductions in energy consumption caused by the introduction of specific energy efficient products and services that were assigned unique efficiency and dollar values. Using this approach, the Board could translate the size of the reduction in energy usage caused by the number of "rated" products and services included in an energy efficiency program by class of service into an agreed dollar credit, an adjustment to the utilities' return on equity, or similar incentives. In the final analysis, any credit afforded the utilities for energy efficiency initiatives should be directly tied to affirmative, tangible actions taken to enhance efficient energy consumption, rather than predicated on subjective, after-the-fact lost revenue guesstimates.

Regardless of the measurement metric ultimately adopted, the Board must limit any utility compensation to lost revenues or reductions in energy consumption that have a demonstrable nexus to the utilities' energy efficiency initiatives. It is important that no credit be given for exogenous factors, such as vacillations in the economy, customer attrition, customer-initiated conservation projects, extreme weather events, or other non-energy efficiency program-related reductions, all of which cause reductions in usage wholly unrelated to a utilities' energy efficiency efforts and therefore should not provide a basis for compensation to the utilities. As noted, any actual losses shown to be directly caused by the utilities' energy efficiency and peak demand programs should be offset by any increases in utility revenues that are attributable to the programs.

Incentives and Penalties

As a threshold comment, because the Clean Energy Act makes utility participation in energy efficiency programs mandatory and imposes penalties for non-performance, there is a built-in incentive for utility involvement in such programs. That said, incentives and penalties could take the form of monetary awards or enhancements to a utility's allowed return on its energy efficiency program investments. If a utility exceeds the energy reduction target established by the Clean Energy Act, it should be eligible to receive a monetary award based on a formula that takes into account the results achieved as well as the costs incurred to achieve them. In other words, the incentive should not only encourage a utility to achieve and exceed the energy reduction goals established by the Clean Energy Act, but to do so efficiently and cost-effectively. As alternatives to a monetary award, the Board could (i) upwardly adjust the allowed return the utility would be eligible to receive on its program investments and/or (ii) permit the utility to "bank"/carry over to a future year excess reductions achieved in a given year to offset any shortfalls in future performance. In all instances, the utility's performance in cost-effectively reducing energy usage and peak demand should determine the amount of incentive the utility is eligible to receive.

Penalties should be assessed in the same manner for a utility that fails to achieve the prescribed energy usage reduction goals set forth in the Clean Energy Act. The severity of the penalty should take into account the extent to which the utility underperformed and the costs incurred to achieve those results. An example of this approach is Pennsylvania's Act 129, the law that established the Commonwealth's energy efficiency program and usage reduction targets. Act 129 provided for significant penalties—between $1 million and $20 million--to be assessed against a utility that failed to achieve the Act's mandated energy and peak reduction targets. The law required the utility to be responsible for payment of any such penalties and prohibited it from seeking to recover the penalty from ratepayers. It would be appropriate for the Board to likewise establish an appropriate range of monetary penalties tied to the utility's level of underperformance and to deny recovery of such penalties from ratepayers.

Alternatively, the Board could also adopt a penalty structure that would deny recovery of a certain percentage of program-related costs incurred during a year in which a utility fails to achieve its Clean Energy Act performance goals, with the amount of cost recovery denied directly linked to the utility's level of non-performance. The Board could implement such an approach by establishing a "holdback" arrangement, whereby a certain percentage of total program costs incurred by a utility are held in abeyance from expedited or timely cost recovery, pending a determination by the Board whether the utility has achieved its energy reduction goals. If the goals are met or exceeded, the amount held back would be released to the utility, together with any incentive deemed appropriate based on the utility's performance. However, if the utility fails to achieve program goals, recovery of all or a percentage of the holdback would be denied the utility, and the utility could be subject to further penalty if appropriate based upon the utility's level of non-performance.

Incentives and penalties should be scaled in some fashion to assure that they provide an ongoing incentive to the utilities to promote energy efficiency. For example, under the "holdback" approach, at least 20-25% of costs incurred should be deemed "in play" through the incentive/penalty mechanism. Bill credits could be utilized as the vehicle to return monies to ratepayers from a utility found to have underperformed its goals.

3. Caps on Rate Impact

NJLEUC strongly supports the implementation of rate caps, not only for the energy efficiency and peak demand programs at issue, but a generic cap on all energy-related programs pursued by the Board and the State. As mentioned by Rate Counsel at the last technical meeting, approximately 30% of residential ratepayers currently have difficulty paying their utility bills, or are forced to forego other necessities to do so. As we have stated repeatedly in the past, the situation for New Jersey's financially-challenged business community is no different. In addition to paying energy costs that are among the nation's highest, the State's large businesses have contributed millions of additional dollars annually to fund a multitude of programs designed to, among other things, upgrade utility electric and natural gas infrastructure, expand transmission, and subsidize unregulated nuclear power plants and solar and offshore wind facilities.

Adding to this burden, the recent FERC MOPR Order may soon require ratepayers to pay significantly higher capacity costs designed to "offset" the competitive impact of these state subsidies on the wholesale markets—essentially compelling ratepayers to pay twice for these programs. In their totality, the state and federal programs, whose costs are generally assessed on a usage basis, impose a significant financial burden on ratepayers over and above the cost of energy supply and transportation services. However, ratepayers, and in particular large energy users, should not be viewed as regulatory ATM machines, with endless revenues to be continually tapped to support new and expanded energy initiatives. There should be no question that energy costs are frequently cited as a significant factor why businesses elect to downsize, exit, or not locate their operations to New Jersey.

Given the many initiatives currently under consideration as part of the Governor's Energy Master Plan, it is particularly appropriate to establish a rate cap that places a fair limit on ratepayers' financial exposure to these many programs. To be clear, NJLEUC does not limit this comment to the proposed utility energy efficiency and peak demand programs under the Clean Energy Act. Rather, we encourage the Board and the State to view holistically all current and proposed energy programs, including previously-approved utility programs whose costs are currently being paid by ratepayers, and to establish an appropriate outer boundary for ratepayer responsibility for all program-related costs paid for electric and natural gas service.

Rate caps are important to prevent near-term rate shocks and spikes associated with the implementation of new programs, and to limit the overall exposure of ratepayers who must pay for these programs, but who in many instances do not receive any benefits from them. For new programs, a reasonable range should be established in which a cost recovery surcharge could "float", up or down, from year to year. More importantly, however, the Board should establish an all-in cost recovery cap that will define the total extent of ratepayer cost responsibility for *all* utility and other energy-related programs. Once established, barring extreme or unanticipated circumstances, the cap should be treated as an inviolate, not-to-exceed outer spending boundary. In the alternative, the cap could be defined by annual changes in identified benchmark indexes, such as the Consumer Price Index for New York/New Jersey/Pennsylvania, which could be utilized as reference points.

Appropriately set rate caps will have the benefit of providing certainty to ratepayers and limit their exposure to rate hikes and rate spikes that are unrelated to supply costs. Caps could also be utilized by the Board as a "scarcity-based" budgeting device for energy programs, limiting the total costs payable by ratepayers for the Board's and State's energy initiatives. This approach would facilitate the development of improved cost-benefit analysis, program evaluation methodologies and standardized metrics to facilitate program analysis and prioritizing program choices.

It is also evident that rate caps will be needed for the utility energy efficiency programs here at issue. While the utilities and their supporters have stated repeatedly that their energy efficiency programs are expected to reduce ratepayer costs, it is noteworthy that they have not expressed a willingness to establish rate caps. The Board should resolve this seeming non-sequitur in favor of ratepayers. If it is truly the case that costs will decline and customer savings will occur, the utilities should have the courage of their convictions and agree to appropriately cap program costs. We suggest a cap set at a percentage of distribution costs, as opposed to a percentage of the total customer bill as suggested in staff's Scenario 1. There is no reason why a cap should include supply-related costs and other unrelated components of the customer's total bill.

Rate Decoupling

NJLEUC continues to oppose unconstrained revenue coupling as a *quid pro quo* for utility support of energy efficiency and peak demand reduction programs. For the past decade, in numerous contexts before the Board and the Legislature, stakeholders have been unable to reach consensus regarding the implementation of rate decoupling, and for good reason. Rate decoupling represents a significant departure from traditional ratemaking principles as it would, for the first time, *guarantee* a utility an authorized level of revenues each year, rather than afford the utility an *opportunity* to prove entitlement to recoup its reasonable and prudently incurred costs. Proponents of rate decoupling claim that adoption of decoupling is necessary to gain utility support for energy efficiency programs that will cause reduced sales of energy. However, because decoupling would provide the utilities with guaranteed revenues, it would not provide an affirmative incentive to utilities to support efficiency programs, but only render the utilities indifferent to the programs' success or failure.

To overcome this indifference, other states have adopted mechanisms such as performance targets or efficiency incentives to induce utilities to actually promote energy efficiency programs, as opposed to merely tolerating them. As noted, in New Jersey, the issue of incentives has been rendered moot by the Clean Energy Act, which requires the utilities to reduce electric and gas usage to targeted levels by dates certain or be penalized for their failure to do so.

From a ratemaking perspective, rate decoupling is the ultimate example of single issue ratemaking. As applied here, decoupling would focus solely on a utility's costs and revenues associated with the energy efficiency and peak reduction programs, as opposed to an overall assessment of the utility's financial performance and health, as would occur in a base rate case. Single issue ratemaking is therefore highly disfavored because it does not present an accurate picture of the utility's overall finances and may lead to a utility over-earning its authorized return.

Further, it can be difficult to determine what portion of a utility's revenue fluctuations above or below the baseline revenues established by decoupling are attributable to the utility's conservation efforts, as opposed to wholly unrelated factors such as extreme weather, economic downturns, business closures, housing foreclosures, shifting population patterns, independent conservation efforts by customers and a host of other factors. Decoupling can therefore credit a utility for reductions in usage that have nothing whatsoever to do with the utility's energy efficiency and conservation initiatives. At the technical meeting, the utilities and other proponents of rate decoupling appeared to espouse a form of generalized rate decoupling, which would fully credit the utilities for reductions in usage caused by these exogenous events. This approach is quite different from the "decoupling" programs approved for New Jersey Natural and South Jersey Gas, which compensate the utilities only for benefits directly associated with their programs. It is assumed that these programs represent the type of "limited decoupling" referenced in staff Scenario 3.

If adopted, generalized decoupling would provide guaranteed annual revenue streams to the utilities, thereby reducing or eliminating the risks associated with the utilities' efficiency programs. It follows that in such a circumstance, the utilities' authorized return on equity should be significantly reduced to reflect the largely risk-free nature of the investments. It is noteworthy that the proponents of decoupling do not agree that it is appropriate to reduce the utilities' ROE in these circumstances.

It should also be underscored that rate decoupling can cause distorted market pricing signals to consumers, which could inhibit their participation in utility programs. From a consumer's perspective, a successful utility energy efficiency program that reduces consumption on a utility's system in year one would lead to a rate increase in year two, while an unsuccessful year one program that increases consumption on the utility's system would produce a rate decrease in year two. Customers who reduce their usage would therefore ultimately not be rewarded for their efforts, as the utility's rates would be permitted to increase to offset the reduced usage.

Large customers, which secure management approval of proposed energy conservation projects based on projected future cost savings, could be frustrated in their efforts because, in a decoupled rate environment, the reduced usage caused by the projects would lead to future rate increases, rather than the decreases that have historically provided the impetus for such projects. It is therefore important for the Board to view the incentive issue from both the utility and customer perspectives, as decoupling could cause perverse incentives that would stifle, rather than facilitate, conservation programs.

Further, rate decoupling provides little benefit to large energy users that do not pay volumetric service rates, but instead take service under tariffs that enable utilities to recover most of their costs of service through monthly demand charges, rather than the customers' actual usage. In effect, these rates are already decoupled from usage, so there is little to be gained from these customer classes by including them in a broader rate decoupling framework. In fact, numerous states that have adopted some form of rate decoupling have exempted large commercial and industrial customers from decoupled rate regimes for this reason.

In sum, NJLEUC urges the Board to use a well-devised system of financial incentives and penalties, tied to objective and measurable performance metrics, as the vehicle to incentivize utility energy efficiency and peak reduction initiatives. The Board should provide utilities fair compensation for their energy conservation efforts, but avoid adopting mechanisms that over-compensate the utilities or provide duplicative compensation. The Board should also implement rate caps that appropriately limit ratepayers' overall exposure to energy program costs.

NJLEUC appreciates the opportunity to provide these comments to the Board and will continue to participate in this process.

Respectfully submitted,

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Attorneys for the New Jersey
Large Energy Users Coalition

January 3, 2020

Docs #4098306-v1

VIA ELECTRONIC MAIL (energyefficiency@bpu.nj.gov)

January 3, 2020

Honorable Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 3rd Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: IN THE MATTER OF THE IMPLEMENTATION OF P.L. 2018, c. 17 REGARDING THE ESTABLISHMENT OF ENERGY EFFICIENCY AND PEAK DEMAND REDUCTION PROGRAMS
BPU DOCKET No. QO19010040

Dear Secretary Camacho-Welch:

New Jersey Natural Gas Company ("NJNG") looks forward to working with the Board of Public Utilities' ("BPU") on the implementation of P.L. 2018, c. 17 regarding the establishment of energy efficiency and peak demand reduction programs ("Clean Energy Act"). NJNG participated in October 31, 2019 and December 13, 2019 Technical Working Group meetings on Cost Recovery and previously submitted comments on November 14, 2019. Through this submission, we are responding to the BPU's December 19, 2019 Request for Comments on these issues.

In regard to the specific scenarios posed in that notice, NJNG supports the comments filed today by Gabel Associates in this matter. NJNG also supports the general comments filed today by the New Jersey Utilities Association. In the interest of streamlining the public record, NJNG will not readdress the content covered within those responses.

However, as noted in our November 14th submission, NJNG would like to strongly express support for decoupling. Through our experience with the Conservation Incentive Program, a modified form of decoupling in place since 2006, we have proven that companies can successfully embrace strategies that help reduce customer energy usage and advance public policy. It can change the culture of the company. Management is focused on reliability and delivering outstanding customer service, instead of obsessing over variations in usage patterns.

There are no marketing efforts devoted to encouraging our customers to increase their energy usage (e.g. no promotion of pool heaters or “outdoor rooms”). All employees receive updates on new energy efficiency programs and special promotions to engage customers on energy conservation. Employees are encouraged to be champions for energy efficiency and our call center even has metrics for proactively sharing energy saving tips. We would be happy to share more details about our experience to highlight how the alignment of priorities can be transformative. If New Jersey is going to be successful in reaching the aggressive clean energy goals and seek the rejoin the ranks of other states leading on clean energy, the state must support and approve strategies like decoupling.

NJNG appreciates the opportunity to provide comments on these topics. We look forward to working with the Board and other stakeholders as the State considers how to restructure the approach to energy efficiency as to enable the utilities to reach the aggressive clean energy goals established by Governor Murphy’s administration. Please feel free to contact me if you need any additional information regarding these issues.

Respectfully submitted,

Anne-Marie Peracchio

Anne-Marie Peracchio
Director- Conservation and Clean Energy

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January 3, 2019

VIA ELECTRONIC MAIL
Aida Camacho-Welch
Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
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energyefficiency@bpu.nj.gov

The New Jersey Utilities Association (NJUA) represents investor-owned utilities that provide electric, natural gas, telecommunications, water and wastewater services to residential and business customers throughout the State. I am writing on behalf of the electric and natural gas companies ("the utilities") that are members of the NJUA to present a high-level response to the broader questions posed in the "Cost Recovery Stakeholder Scenarios". Specifically, the scenarios ask for feedback regarding the makeup of a utility's cost recovery mechanism for energy efficiency and considerations regarding incentives and penalties. NJUA's member companies reserve the right to submit comments on an individual basis.

As described in more detail below, a cost recovery mechanism should include:

1. Full recovery of all reasonable and prudent costs incurred;
2. Recovery of and on any capital investment at the utility's weighed average cost of capital;
3. A decoupling or lost revenue recovery mechanism to remove the disincentive for utilities to promote energy efficiency; and
4. A performance incentive structure

It is important to consider that New Jersey's energy utilities recover the cost of their investments in the distribution system largely through volumetric rates, charged per kWh or per therm. There is thus, as currently structured, a fundamental disincentive in New Jersey's ratemaking process and designs to invest in energy efficiency programs. Implementation of energy efficiency programs result in lower throughput (sales) on the distribution system, while the costs of providing electric and gas distribution service (*e.g.* capital investment, and operation and maintenance expense) of the electric and gas distribution systems do not decrease. **Allowing the current structure and resulting disincentive to continue is in direct conflict with the State's goals regarding implementation of energy efficiency. To meet those goals, New Jersey must embrace 1) cost recovery for lost revenues and energy efficiency program implementation and 2) incentives to support performance.** The State has already recognized the need to incentivize energy efficiency investments in law. The language and structure of the Clean Energy Act and section 13 of the Regional Greenhouse Gas Initiative ("RGGI") (N.J.S.A.48-3-98.1), along with the historic treatment of public utility energy efficiency investment in New Jersey, is clearly consistent with the utilities earning a rate of return on these investments.

N.J.S.A.48:3-87.9e.(1) provides that each electric public utility and gas public utility shall file annually with the board a petition to recover on a full and current basis through a surcharge *all reasonable and prudent costs incurred* as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, *including but not limited to recovery* ***of and on capital investment****,* and the ***revenue impact of sales losses resulting*** from implementation of the energy efficiency and peak demand reduction schedules, *which shall be determined by the board pursuant to section 13 of P.L. 2007, c. 340 (C.48:3-98.1).* (Emphasis added).

Following the provision cited above, N.J.S.A.48:3-87.9e.(2) and N.J.S.A.48:3-87.9e.(3) require, respectively, that the Board establish incentive and penalty structures. Next, N.J.S.A.48:3-87.9.e.(4) states:

> The adjustments made pursuant to this subsection may be made through adjustments of *the electric public utility's or gas public utility's* ***return on equity related to the energy efficiency or peak demand reduction programs only, or a specified dollar amount,*** reflecting the incentive structure as established in this subsection. The adjustments shall not be included in a revenue or cost in any base rate filing and shall be adopted by the board pursuant to the Administrative Procedure Act. (Emphasis added).

This provision confirms that the utility will <u>have</u> a return on equity "related to" its energy efficiency programs. Similarly, section 13 of RGGI, (N.J.S.A.48:3-98.1), includes the following cost recovery language in subsection b. and in the definition of "program costs" in subsection d.:

> b. An electric public utility or a gas public utility seeking cost recovery for any program pursuant to this section shall file a petition with the board to request cost recovery. . . . *Ratemaking treatment may include placing appropriate technology and program cost investments in the respective utility's rate base, or recovering the utility's technology and program costs through another ratemaking methodology approved by the board, including, but not limited to, the societal benefits charge . . . All electric public utility and gas public utility investment in energy efficiency . . . programs may be eligible for rate treatment approved by the board, including a return on equity, or other incentives or rate mechanisms that decouple utility revenue from sales of electricity and gas.* (Emphasis added).
>
> d. … "Program costs" means all reasonable and prudent costs incurred in developing and implementing energy efficiency, conservation, or Class I renewable energy programs approved by the board pursuant to this section. *These costs shall include a full return on invested capital and foregone electric and gas distribution fixed cost contributions* associated with the implementation of the energy efficiency, conservation, or Class I renewable energy programs until those cost contributions are reflected in base rates following a base rate case if such costs were reasonably and prudently incurred. (Emphasis added).

As described above, the law in New Jersey allows electric and gas utilities to receive a return on energy efficiency investments and lost revenues related to energy efficiency programs.

Further, the Clean Energy Act of 2018 statutorily requires utilities to deliver energy savings. It is therefore critical, that when defining performance incentives and penalties for utilities, such incentives and penalties relate to the development, implementation, and administration of energy efficiency programs that are under the utilities' control. In their 2019 State Energy Efficiency Scorecard[1], ACEEE considers recovery of the direct costs associated with implementing energy efficiency programs as a minimum threshold requirement for every state to meet. Fixed cost recovery (in the form of either full revenue decoupling or lost revenue adjustment mechanisms) and performance incentives are held as best practices, with evidence showing that the top performing states on the scorecard all earn points in the category for Performance Incentives and Fixed Cost Recovery.

With that, NJUA recommends that an appropriate mechanism for recovery of lost revenue from energy efficiency programs is needed to align State energy efficiency policy goals with utility business models. A decoupling or lost revenue recovery mechanism will align the utilities with the goals of the State and make investment in energy efficiency comparable to investments in infrastructure. While it has been argued that the Clean Energy Act removed a utility's disincentive to invest in energy efficiency, providing a decoupling mechanism or lost revenue recovery mechanism has the potential to encourage utilities to achieve greater energy reductions. States that achieve the most energy reductions, such as Maryland, Massachusetts, and New York, have all adopted mechanisms to remove the throughput incentive. As noted above, utility recovery of lost revenues is authorized by the Clean Energy Act of 2018 and the "RGGI" law (N.J.S.A. 48:3-98.1), indicating that the State recognizes such recovery is necessary for successful programs.

Also, utilities should be permitted to invest capital in the provision of their energy efficiency programs. Under this approach, customers can pay program costs over the same period they realize the benefits. As noted above, the Clean Energy Act provides that utilities are entitled "to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency and peak demand reduction programs . . . including but not limited to recovery of and on a capital investment . . ." To best encourage and reward individual utility performance, flexible cost recovery and incentive options are necessary. The return utilities receive from these investments should be commensurate with the time-period over which the investment is recovered and must fully compensate the utilities for their costs.

And when capital is invested, the utilities should be allowed to earn a return at their allowed weighted average cost of capital consistent with the current recovery of utility sponsored energy efficiency investments. The cost recovery mechanism should align the State's goals with the utilities' incentives. Approving a rate of return lower than the utility's rate of return will make it more attractive for a utility to make infrastructure investments rather than to invest in energy efficiency. Further, the proxy groups used to set the ROE for a utility in a base rate case may already include utilities that have clauses with lost revenue recovery mechanisms. Therefore, all else equal, investing in energy efficiency would lower the Company's overall return below what was allowed in its last base rate case, which already factored in contemporaneous recovery and recovery of lost revenues from the proxy group.

Incentive opportunities should be included in a utility's cost recovery mechanism to encourage and reward effective performance. Performance incentive mechanisms that are achievable, linear, and meaningful will

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[1] ACEEE, October 2019, *The 2019 State Energy Efficiency Scorecard*, pg. 42, available at https://aceee.org/research-report/u1908.

generate focus on long-term goals. Simplifying the mechanism defining guidelines will allow utilities to focus on and achieve the long-term goals of the Clean Energy Act. Also, the number of Quantitative Performance Indicators (QPIs) should be limited and focused on energy impact. Creating a more limited set of targets creates clear objectives and minimizes distractions for utilities and the Board. QPIs can then be reassessed in year three (post-Clean Energy Act enactment) after programs are established. Further, there should be some deadband around which no incentive or penalty is instituted recognizing the magnitude of factors that cause uncertainty and variability with program performance over time.

Thank you for the opportunity to comment on this very important matter.

Sincerely,

Thomas R. Churchelow
President

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January 3, 2020

Via E-mail (EnergyEfficiency@bpu.nj.gov)

Aida Camacho-Welch, Secretary of the Board
Board of Public Utilities
44 S. Clinton Ave., 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: Energy Efficiency Transition, Cost Recovery Scenarios

Dear Secretary Camacho-Welch:

Please accept these comments on behalf of Public Service Electric and Gas Company ("PSE&G" or the "Company") in connection with the above-referenced matter. PSE&G thanks the New Jersey Board of Public Utilities ("BPU" or "Board") for its initiation of the energy efficiency transition stakeholder process and the opportunity to provide these comments. These comments are being submitted by PSE&G in addition to the comments of the New Jersey Utilities Association, submitted on this date as well.

PSE&G echoes at the outset of these comments what many stakeholders expressed at the October 31 and December 13, 2019 cost recovery technical meetings. Specifically, the State must significantly change the way it engages stakeholders if it is to meet the energy savings requirements of the Clean Energy Act ("Act") and become a national leader in energy efficiency. To meet these ambitious goals it is imperative that the State partner with New Jersey's utilities, and align the State's goals with utilities' business objectives by adopting a cost recovery mechanism for utility energy efficiency programs that authorizes: (1) a return of and on utility costs; (2) full revenue decoupling to break the link between utility sales and revenues; (3) the amortization of costs over the useful lives of the measures; and (4) an incentive and penalty structure that is simple and transparent, and based on quantitative performance indicators.

Introduction

Following the December 13, 2019 cost recovery technical meeting, Board Staff issued a Request for Comments, seeking feedback from stakeholders on four hypothetical cost recovery scenarios. These scenarios were each comprised of certain variable attributes, specifically: Asset/Investment Treatment; Recovery Period; treatment of Lost Revenues; the structure for Incentives/Penalties; Carrying Cost on Over/Under-Recovery; use of the utility's WACC; and application of a Rate Cap.

In these comments, PSE&G will first discuss these attributes. We then comment on each of the four scenarios. PSE&G will also demonstrate in these comments, and in the context of the four scenarios proposed by Staff, that the approach taken in PSE&G's pending Clean Energy Future – Energy Efficiency ("CEF-EE") program (BPU Docket Nos. GO18101112 and EO18101113), implemented effectively, will achieve the State's energy efficiency goals. We will specifically show that with: (1) PSE&G responsible for establishing, implementing, and operating the programs; (2) the Company earning on energy efficiency investments at its allowed rate of return; (3) rate decoupling, to properly align incentives to maximize energy savings; and (4) amortization of the cost of the programs over the lives of the energy efficiency measures employed, PSE&G will meet the energy efficiency objectives of the Clean Energy Act while providing significant bill savings to participating customers, with little to no impact on non-participating customer bills.

The comprehensive CEF-EE program contains several important, and undisputed, benefits for the State and its residents. First, it will reduce participating customers' bills by $5.7 billion through the implementation of a wide variety of energy efficiency measures. With its emphasis on engaging low income and other difficult to reach customer segments, as well as residential and commercial business communities, savings are created for all customers across the State's socioeconomic spectrum. Second, the CEF-EE Program will reduce harmful greenhouse gas emissions and put New Jersey on track to meets its emissions reduction goals. Third, it will help grow the "green economy" right here in New Jersey, including private sector, energy efficiency businesses. The CEF-EE investments will increase employment through the creation of approximately 5,000 jobs and facilitate associated economic activity over the proposed investment period. As part of the job creation associated with CEF-EE, PSE&G envisions a range of employment opportunities for unemployed, under-employed, low- and middle-income New Jersey residents. The utility has been engaged in ongoing, collaborative efforts with the New Jersey Department of Labor and various energy efficiency trade allies to discuss the full range of clean tech job opportunities that CEF-EE will provide, including job training programs throughout the State that will include specific programs to provide employment to residents in some of New Jersey's most vulnerable areas. These employment opportunities will include work with HVAC installation contractors, developers, engineers, plumbers, electricians, builders, retailers, and distributors of other energy efficiency service businesses.

In addition, as noted above, the CEF-EE program can help achieve these benefits with little to no impact on non-participating customers. Figure 1 below provides a graphic depiction of the residential non-participant bill impact for BPU Scenarios 1 and 2 as well as PSE&G's CEF-EE filing.[1] To reasonably compare the BPU Scenarios with CEF-EE, Figure 1 assumes that expenditures under those scenarios ramp up to a maximum of $1 billion annually ($250 million for Utility A and $750 million for Utility B) over 6 years, proportionately to the expenditures under the CEF-EE filing. Further, in addition to including base investment revenue requirements in all cases, and also to provide a more "apples-to-apples" comparison with PSE&G's CEF-EE filing,

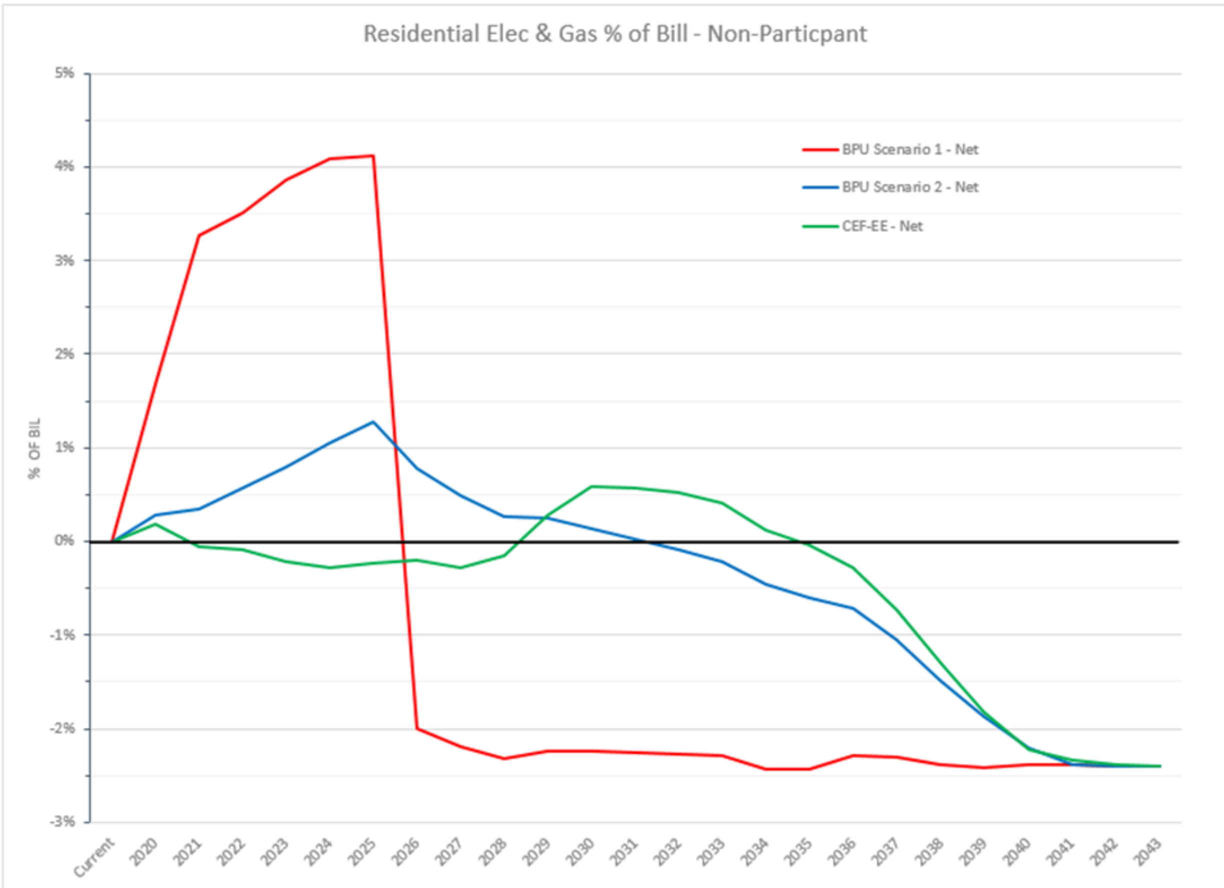
[1] The individual scenarios proposed by Board Staff are discussed in detail below. Under Scenario 1, all utility energy efficiency investments are expensed, while under Scenario 2 the investments are amortized for recovery over time.

the following energy efficiency program costs and benefits are incorporated into all three scenarios depicted in Figure 1:

1) Societal Benefits Clause (SBC) savings – cost savings associated with significantly reducing the current energy efficiency component of the SBC;
2) Market based savings – cost savings associated with reduced wholesale power prices and lower Renewal Energy Certificate ("REC") obligations;
3) Transmission & distribution savings – cost savings associated with lower consumption over time which reduces the necessity, and the cost, of future system upgrades;
4) Existing energy efficiency program savings – cost savings associated with phasing out the Company's existing energy efficiency programs; and
5) Lost revenue recovery – costs shifted from EE program participants to non-participants to recover lost revenues associated with energy efficiency investments (whether through decoupling, lost revenue adjustment mechanism or annual rate cases) and under-recoveries for existing clauses due to lower overall sales recovered in subsequent years.

BPU Scenario 1 clearly shows that if the energy efficiency investment required under the Clean Energy Act is expensed, customers will face immediate and significant rate increases that will be sustained over the life of the program; this approach would also conflict with the ratemaking principle of intergenerational equity (*i.e.*, aligning between the customers who benefit from the measures and the customers who pay for them). BPU Scenario 2, which includes amortization of the investments, better matches the cost to customers with program benefits. PSE&G's CEF-EE filing includes the same key attributes as Scenario 2, and also includes on-bill repayments and accelerated flowback of deferred taxes, as well as a slightly different investment mix and amount. As can be seen in Figure 1, it is clear that the CEF-EE approach offers a cost recovery mechanism that aligns the goals of the Clean Energy Act with the utility's goals, with energy and cost savings to participating customers and little to no impact even to non-participating customers.

Figure 1



Attributes of the Proposed Scenarios

1. Asset/Investment Treatment and Recovery Period -- Utility Program Costs Should Be Amortized Over the Useful Lives of the Energy Efficiency Measures

PSE&G agrees with the consensus opinion expressed at the October 31, 2019 technical meeting that utility energy efficiency program costs should be amortized, not expensed. This rate treatment is consistent with the historic approach towards utility energy efficiency investments in New Jersey, as well as the Clean Energy Act and Section 13 of the RGGI Act.[2]

[2] *See* N.J.S.A. 48:3-87.9e.(1) (utilities shall file annual petitions with the Board to recover "all reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required [by the Clean Energy Act], including but not limited to recovery of and on capital investment"); N.J.S.A. 48:3-87.9e.(4) (adjustments made pursuant to the

As illustrated in Figure 1 above, amortization of investment costs, as provided for under BPU Scenario 2 and the CEF-EE program but not under BPU Scenario 1, reduces customer bill impacts, without significant rate increases to customers. The recovery, or amortization, period should match the useful lives of the energy efficiency investments, so that the customers who pay for the investments are those who receive the benefits of the programs. Indeed, matching benefits with costs is a fundamental principle of utility ratemaking.

Conversely, expensing energy efficiency program costs or setting an artificially short amortization period (see Figure 1, BPU Scenario 1) will result in inequities among customers, as costs will be collected over a shorter period of time than the benefits will last. Expensing energy efficiency program costs will also result in significant and sustained rate increases for customers, including low income customers, which will only be exacerbated by the significant increase in energy efficiency investment the State must make to reach the requirements set forth in the Clean Energy Act.

2. Lost Revenues -- New Jersey Should Join the Leading Energy <u>Efficiency States in the Country and Adopt Electric Revenue Decoupling</u>

It is axiomatic that given their volumetric rate structure, utilities' revenues will decline if sales are reduced in the manner that the Clean Energy Act requires. Not permitting the utilities to recover those lost sales revenues would be unjust and unreasonable, and would contravene the express terms of the Clean Energy Act, which specifically authorizes utility recovery for, among other things, "the revenue impact of sales losses resulting from implementation of . . . energy efficiency."[3] Section 13 of the RGGI Act also permits "rate mechanisms that decouple utility revenue from sales of electricity and gas", and states that the Board "shall allow the recovery of program costs", with "program costs" defined to include "foregone electric and gas distribution fixed cost contributions associated with the implementation of the energy efficiency [program]."[4]

New Jersey, in fact, has successfully implemented revenue decoupling already, as two of its gas utilities have had a form of BPU-approved decoupling for more than a decade, specifically for New Jersey Natural Gas and South Jersey Gas via the Conservation Incentive Program ("CIP"). Anne-Marie Peracchio of New Jersey Natural Gas spoke convincingly at the October 31st meeting about how the CIP was the impetus that changed the company culture from focusing on incremental load growth to promoting energy efficiency.

Clean Energy Act's performance and incentive structure "may be made through adjustments of the electric public utility's and gas public utility's return on equity related to the energy efficiency or peak demand reduction programs only"); N.J.SA. 48:3-98.1(b) (utility energy efficiency programs "may be eligible for rate treatment approved by the board, including a return on equity. . ."); N.J.S.A. 48:3-98.1(a)(3) and (d) (the BPU "shall allow the recovery of program costs" associated with utility energy efficiency programs, with "program costs" defined to include "a full return on invested capital").

[3] *See* N.J.S.A. 48:3-87.9e.1.

[4] *See* N.J.S.A. 48:3-98.1b and d.

In addition to the lessons learned from successful use of decoupling already experienced in the state, below is a list of considerations about implementing lost revenue recovery given the Act's savings goals.

- With no lost revenue recovery, utilities will:
  - Likely file base rate cases more frequently, possibly every year; and
  - Be seen as more risky by credit rating agencies, ultimately leading to higher costs of debt that would result in higher costs to customers.
- Decoupling alone, unlike lost revenue adjustment mechanisms ("LRAM") that recover lost revenue specifically from energy efficiency programs:
  - Removes the utility disincentive to promote energy efficiency in all forms ***and*** to promote distributed energy, which allows utilities to be more innovative; without decoupling, these disincentives still exist irrespective of the Act's mandates to reduce energy usage and associated program cost recovery and incentives/penalties;
  - Provides a method to return revenue increases to customers, which can occur, for example, due to weather impacts or the penetration of electric vehicles (the latter being expected given the State's policy to promote electric vehicles); and
  - Is administratively simple for all stakeholders because it is agnostic as to the drivers of lost revenue, and simply adjusts revenues to levels agreed upon with regulators and other stakeholders.
- Decoupling should mirror PSE&G's Green Enabling Mechanism ("GEM") (included in the Company's CEF-EE filing) and the CIP by having these characteristics:
  - Be on a per-customer basis, maintaining the utilities' incentives to spur economic growth and serve new customers;
  - Be applied on a rate class-by-rate class basis, and applied only to customers in those rate classes that account for large amounts of distribution base rate revenues, ensuring that individual customers will experience *de minimis* impacts on their bills from recovery of lost revenue, thereby not impacting their decision to conserve; and
  - Use an earnings test that mirrors the test under the Infrastructure Investment Program requirements, and a soft rate cap to ensure modest customer rate increases.

As indicated above, PSE&G's GEM provides a revenue decoupling model for the State to follow and is similar to the New Jersey Natural Gas and South Jersey Gas CIP currently in effect. PSE&G submits that the GEM and CIP establish guiding principles for a statewide decoupling mechanism.

3. Incentives/Penalties -- The Incentive and Penalty Structure Should <u>Be Simple, Scalable, Symmetrical, Capped, and Recovered Over Time</u>

PSE&G supports the use of performance incentives and penalties to promote State policy goals and reach the targets outlined in the Clean Energy Act. Performance should be determined based on the results of the Quantitative Performance Indicators ("QPI"). In relating performance to the award of an incentive or payment of a penalty, PSE&G recommends following best-practice elements, which are illustrated in Figure 2 below:

- **Simple and transparent**. The mechanism must be as simple as possible, to translate performance on QPIs into incentives and penalties.

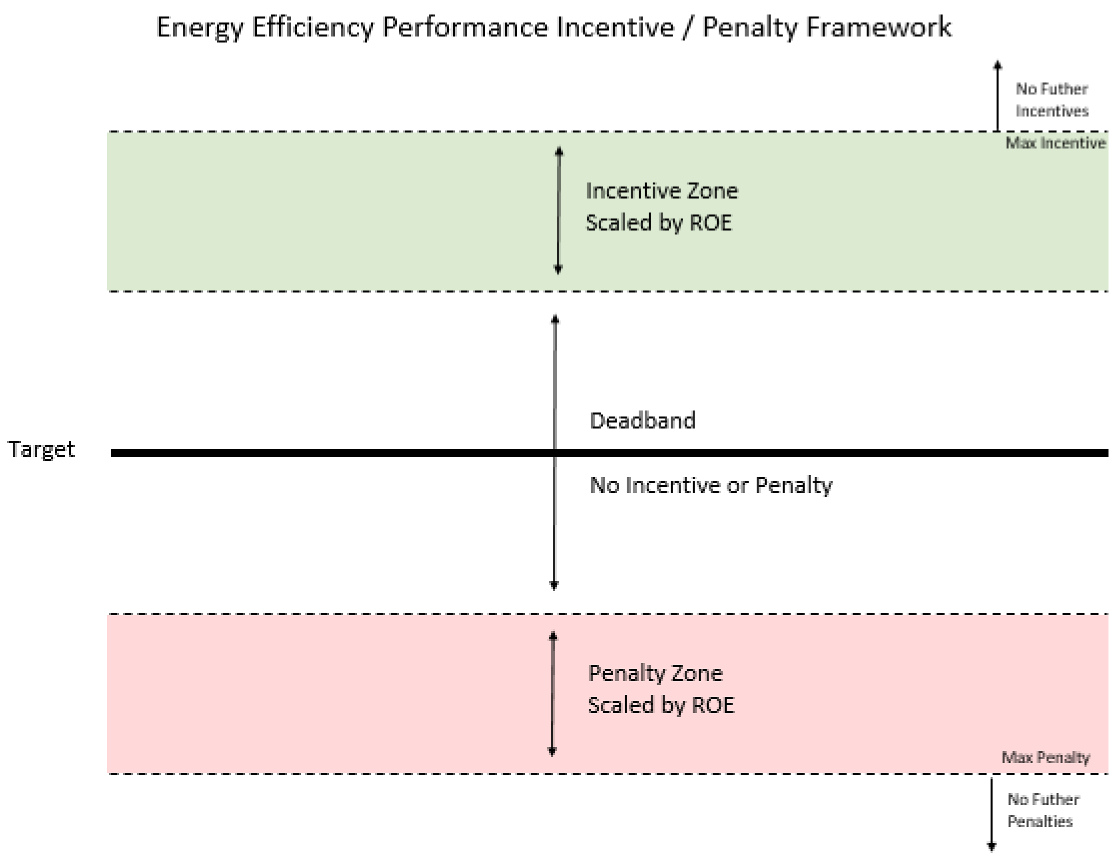
- **Dead band**. There should be a dead band around the targets in which no incentive or penalty is incurred.

- **Cap and floor**. The existence of a cap and floor serves to limit exposure by both customers and utilities in the event of significant under- or over-performance.

- **Linear scaling.** The incentives and penalties should scale linearly between the floor and the dead band, as well as between the dead band and the cap.

- **Recovered over time**. This approach aligns the incentive or penalty with the time over which customers receive the benefit from EE investment. It will also minimize the rate volatility that could flow from awarding the entire incentive or imposing the entire penalty in a single year.

Figure 2



To satisfy these guiding principles, PSE&G recommends that the incentive or penalty be awarded through an adjustment, up or down, to the return on equity ("ROE") earned on the energy efficiency investment at issue. This approach will naturally satisfy the principle to recover the incentive/penalty over time, and will keep the mechanism simple and transparent by tying it to the utility's existing ROE. This aligns with practices in both Illinois and New York, leading EE states that have both rate-of-return on EE investment and performance incentives.

4. WACC -- Utility Program Costs Should Be Allowed a Return On The Unamortized Balance Using a Rate Equal to the Utilities' Weighted Average Cost of Capital ("WACC")

Consistent with the historic approach towards utility energy efficiency investments in New Jersey, as well as the provisions of the Clean Energy Act and Section 13 of the RGGI Act described above (*see* note 1), utility program costs should be allowed a return on the unamortized balance using a rate equal to the utilities' weighted average cost of capital ("WACC"). The utilities' WACC is approved in base rate cases after BPU and Division of Rate Counsel review. As noted, Board precedent, consistent with the relevant statutes, is to use utilities' WACC for return on investment when establishing the cost recovery mechanism for energy efficiency programs under the RGGI law. Reducing utility returns on energy efficiency investment below the WACC (or worse, requiring that this investment be expensed) would make investment in energy efficiency far less attractive than investment in utility infrastructure. It makes no sense to allow lower returns on energy efficiency investment than on investments in new transformers, electric circuits, or gas M&R stations, when the Governor, the Legislature, and the Board itself have made clear the State's policy to increase energy efficiency.

Furthermore, authorized utility ROEs should not be adjusted were the Board to allow for electric decoupling. Such an adjustment would ignore all of the other factors that influence an ROE decision, such as utility risk associated with cost overruns. Moreover, utility ROEs are typically set based on a proxy group range that includes decoupled utilities. Thus, any risk reduction is already embedded in the ROE established in the utility's most recent base rate case.[5] It is also worth noting that full decoupling will not guarantee utilities earn their allowed rate of return. Decoupling addresses revenues only. If wages increase, for example, without a corresponding cost offset, the utility will not earn its allowed return, regardless of whether it has decoupling or not, because its costs will be higher than the costs used to set base rates, and putting aside customer growth, its revenues can no longer be higher than those established in the rate case.

5. Rate Cap – Imposition of a Rate Cap Would <u>Undermine the State's Energy Efficiency Goals</u>

A cost recovery mechanism that includes a rate cap would undermine the state's energy efficiency requirements expressed in the Clean Energy Act. If the cap is a "hard cap", precluding any deferral of costs not recovered under the cap, the utility would be incented to significantly reduce its energy efficiency efforts to stay under the bill cap. Doing so would result in the utility not reaching the Act's savings targets, contrary to the State's energy goals, and risking the assessment of penalties. Alternatively, the Board could establish the bill cap as a "soft cap", with the utility deferring expenses above the cap limit for future recovery. However, if expenditures significantly exceed the bill cap and spending on energy efficiency initiatives continues beyond year one, it would take a significant amount of time before the utility could recover its costs. To avoid this dilemma, energy efficiency program costs should be amortized over the useful lives of the measures. Most participants at the technical conferences appear to agree on this point.

[5] The scenarios proposed by BPU Staff providing for a return on energy efficiency investment (Scenarios 2, 3 and 4) each assume the utility's "Base Rate Case" WACC, or 9.6%, with Scenario 4 proposing a reduction of 200 basis points from that Base Rate Case figure. It is PSE&G's understanding that Staff has thereby withdrawn the suggestion in its initial scenario proposal that the hypothetical utilities operating under those scenarios have a WACC incorporating an 8.5% cost of equity.

Scenarios 1 Through 4

In this section, PSE&G discusses each of the 4 Scenarios, in light of the discussion above regarding the attributes characterizing each Scenario.

Scenario 1

Asset/Investment Treatment	Expense
Recovery Period	Annual
Lost Revenues	No Decoupling
Incentives/Penalties	% of Savings / $ for Negative Benefits
Carrying Costs on Over/Under	Treasury bill
WACC	None
Rate Cap	2% annual increase of total customer bill

Comments:

As several speakers at the December 13, 2019 technical meeting commented, this Scenario represents a "worst case" approach and will not achieve the savings that the Act requires in a cost-effective manner. It would also violate the Act, which permit the utilities to earn on their energy efficiency investments and recover lost revenues.[6]

Expensing costs for full annual recovery, as assumed under Scenario 1, would create immediate and sustained rate shock for customers, especially considering the significant expenditure entailed to achieve the energy savings that the Act requires (as shown in Figure 1 on page 3). With all costs expensed, the total revenue requirement for Utility A and Utility B would all be collected as expenditures are made. For a gas and electric utility such as PSE&G, assuming that 80% of costs are attributed to electric programs and 20% are allocated to gas programs, and putting aside the bill cap included in this Scenario, combined electric and gas customers would see an immediate, annual bill increase of approximately 3%, ramping up to 4% as expenditures ramp up to $1 billion per year, when incorporating a reduction to the current SBC and the net benefits of energy efficiency described in the Introduction to these comments.

The lack of any mechanism for the utility to recover lost revenues on energy efficiency investment under this Scenario is contrary to the Clean Energy Act and should not be considered. For all of the reasons listed above, PSE&G recommends a full decoupling mechanism. Further, the Company does not support a rate cap on recovery of program investment and recommends an ROE adjustment for the incentive/penalty structure.

[6] *See* N.J.S.A. 48:3-87.9e(1) (annual utility cost recovery filings shall seek "to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required pursuant to [the Act], including but not limited to recovery of and on capital investment, and the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules[.]").

The cost recovery methodology in Scenario 1 would adversely impact utilities' credit metrics, which in turn would result in higher debt costs for utilities that customers will absorb. Put simply, Scenario 1 would have an adverse impact on customers, utilities, and the State's ability to achieve its energy goals. As such, the Board should not consider this Scenario further.

Scenario 2

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-life
Lost Revenues	Full decoupling
Incentives/Penalties	Fixed dollar incentive/fixed dollar penalty
Carrying Costs on Over/Under Recovery	Two-year treasury bill plus 60 basis points
WACC	Base Rate Case
Rate Cap	No Cap

Comments:

Scenario 2 aligns the interests of the State, customers, and utilities, and will drive meaningful energy reductions consistent with the levels required by the Act. For that reason, the BPU should adopt most of the key attributes of this Scenario.

As PSE&G noted above in connection with Figure 1 and in its November 14, 2019 written comments following the first cost recovery technical meeting, amortizing costs mitigates customer bill impacts, allowing for the significant ramping up of investment in energy efficiency that the Act requires. Amortization is also consistent with the Act and the RGGI Law, N.J.S.A. 48:3-98.1, as well as the historic approach towards utility energy efficiency investments that the Board has taken. As shown in Figure 1, Scenario 2 does not result in the initial and sustained rate shock that is associated with Scenario 1. Further, with utility administration and on-bill repayments as proposed in the Company's CEF-EE filing, customers will see little to no net bill impact.

With respect to the incentive/penalty structure, the Company recommends an adjustment to the ROE for the program investment. If a fixed dollar incentive/penalty is implemented, as proposed under Scenario 2, it should be recovered or refunded over the remaining life of the investment to provide rate stability.

Of the four scenarios presented, Scenario 2 represents the best option for delivering energy savings in a cost-effective manner, while also aligning with the utilities' objectives. This scenario most closely resembles the cost recovery mechanism proposed in PSE&G's CEF-EE filing, and, as shown in Figure 1, when the additional features of PSE&G's CEF-EE filing are overlaid on Scenario 2 (specifically, reduced program expenditures and repayments by participants), the State's energy efficiency goals can be met with virtually no negative impact on customers. The Board should adopt Scenario 2 with the exception that the incentive/penalty methodology should be an adjustment to the ROE for program investment instead of a fixed dollar amount as discussed in the Incentive/Penalty section above.

<u>Scenario 3</u>

Asset/Investment Treatment	Amortization
Recovery Period	Weighted-Life
Lost Revenues	Limited Decoupling
Incentives/Penalties	% of return (weighted by QPI performance)
Carrying Costs on Over/Under Recovery	2 Year Treasury-Bill
WACC	Base Rate Case
Rate Cap	No Cap

Comments:

It is unclear what this Scenario contemplates when it references "limited decoupling." For the reasons stated above, in its November 14, 2019 written comments, and in other submissions to the BPU, PSE&G believes that full decoupling is needed for the State to achieve its energy efficiency goals. Any form of "limited decoupling" that is adopted should be transparent and formulaic so that the State's and utilities' goals are aligned. Examples include: (1) a variation of the Conservation Incentive Program that the Board has approved for New Jersey Natural Gas and South Jersey Gas, tailored to the other gas utilities and the electric utilities; (2) a decoupling mechanism that excludes weather impact on residential electric sales; and (3) a lost revenue adjustment mechanism that includes recovery of lost sales generated by utility and non-utility programs, such as the New Jersey Clean Energy Program, and is forward looking to reduce the lost revenue recovery lag.

As discussed above, the Company agrees with the proposed incentive / penalty structure of an adjustment to the ROE on the program investment.

Scenario 4

Asset/Investment Treatment	Amortization
Recovery Period	10 years
Lost Revenues	No Decoupling
Incentives/Penalties	% of return (weighted by QPI performance)
Carrying Costs on Over/Under Recovery	Two-year Treasury bill plus 60 basis points
WACC	Base Rate Case less 200 basis points
Rate Cap	3% annual increase of total customer bill

Comments:

The sharp decrease in the allowed ROE of 200 basis points, coupled with the inability to recover lost revenues in violation of the Act, would not align the State's and utilities' goals. In fact, if adopted, this Scenario would make investment in energy efficiency uneconomic, if not punitive. Notably, the methodology in this Scenario is significantly less favorable to utilities than the cost recovery mechanisms that the Board has approved over the past decade pursuant to N.J.S.A. 48:3-98.1.

All other factors considered equal, investing in an energy efficiency program with a lower ROE than that which the utility is allowed will drive the Company's overall return below what the Board has allowed in the most recent rate case. This would impair the Company's ability to raise capital, and credit agencies would certainly look negatively upon this structure with a significantly lower ROE and no lost revenue recovery.

Furthermore, by amortizing costs over a fixed period (10 years), this Scenario breaks the link between the bill impacts of the program and the benefits the program generates. Following ratemaking best practices, the benefits and costs should be matched as closely as possible. Using an artificially shorter time period, such as 10 years will cause the bill impact to peak earlier in the program, reducing the near-term net benefits generated. Lastly, benefits continue to accrue beyond the revenue requirement, resulting in inter-generational inequity between customers who benefit from the measures and the customers who pay for them. Traditional infrastructure investments are recovered over their average useful lives as determined through a depreciation study. A gas main, for example, is not recovered over an arbitrary 7-year period but rather over its expected life so that all customers who benefit from the gas main contribute toward it. The same approach should be utilized for energy efficiency investments. The societal benefits of the installed measures will last over the life of the investment and thus costs should be recovered over that same period. Finally, for the reasons stated in the Introduction above, the Board should not implement a rate cap on program recovery.

The Board should not consider Scenario 4 given the deleterious impact it would have on utilities.

Conclusion

Scenario 2 based on an ROE adder incentive rather than a fixed dollar amount, is the most appropriate utility incentive and cost recovery construct to support the State's energy reduction goals while at the same time balancing customer bill impacts and utility business objectives. Further modifying that Scenario to incorporate all features of CEF-EE, as shown in Figure 1, will further mitigate customer rate impacts. The combination of amortizing program costs over the weighted life of the energy efficiency measures, permitting a return on energy efficiency investments, and authorizing full revenue decoupling are the three policy pillars that are needed to make New Jersey a national leader in energy efficiency. For the foregoing reasons, the Board should adopt Scenario 2 with an ROE adjustment rather than fixed dollar incentive structure, along with the on-bill repayment feature of CEF-EE. PSE&G once again thanks the Board for the opportunity to provide these comments.

Respectfully submitted,

Joseph F. Accardo, Jr.

NJBPU Notice of November 26, 2019
Energy Efficiency Technical Meeting – Cost Recovery
Rockland Electric Company Comments

Executive Summary

Rockland Electric Company ("RECO" or the "Company") supports the Energy Efficiency ("EE") goals of the New Jersey Clean Energy Act[1] ("CEA"). The Board of Public Utilities' ("BPU") Notice expressed BPU Staff's interest in reviewing how EE cost recovery and EE incentives and penalties would be implemented using the hypothetical program costs and capital structure of four utility scenarios. In these Comments, the Company sets out its recommendations for cost recovery, incentives and penalties, and explains how these mechanisms would be implemented. Specifically, the Company recommends that the BPU establish a cost recovery framework that provides for the recovery of lost revenues, the amortization of EE investments with a return on the EE investments, and the development of incentives based on the achievement of energy reduction targets. The Company also recommends that the imposition of penalties be delayed to allow the utilities a ramp up period to develop and implement their EE programs. The Company's recommendations are based on both the legislature's intent, as expressed in the specific language of the CEA, and on studies that identify the state regulatory frameworks that support successful energy efficiency programs.[2]

At the outset, it is important to review the EE cost recovery sections of the CEA, which memorialize the legislature's intentions for utility cost recovery. The legislature expressly stated in the CEA that the utilities' cost recovery "shall" include, but is not limited to, the recovery of program costs,[3] lost revenues,[4] and a return on utility EE investments.[5] The CEA also references Section 13 of the Regional Greenhouse Gas Initiative Act ("RGGI"),[6] which states that the costs of RGGI programs "shall" include a full return on utility investments in their EE programs.[7] The

[1] P.L. 2018, Chapter 17. The EE portion of the CEA is codified at *N.J.S.A.* 48:3-87.9.

[2] *See, e.g., The 2019 State Energy Efficiency Scorecard,* American Council for an Energy Efficient Economy ("ACEEE") (October 2019) ("ACEE 2019 Scorecard"). (For example, the ACEEE Scorecard includes a list of the state EE programs with the highest reductions in energy usage, which includes Massachusetts, California, Rhode Island, Vermont, and New York.). Available at https://aceee.org/research-report/u1908.

[3] *See N.J.S.A.* 48:3-87.9e (1) ("Each electric public utility and gas public utility shall file annually with the board a petition to recover on a full and current basis through a surcharge all reasonable and prudent costs incurred as a result of energy efficiency programs and peak demand reduction programs required pursuant to this section, *including but not limited to* recovery of and on capital investment, and the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand reduction schedules…") (emphasis added).

[4] See footnote 3 above.

[5] See footnote 3 above.

[6] L.2007, c. 340, § 13 codified at *N.J.S.A.* 48:3-98.1

[7] *See N.J.S.A.* 48:3-98.1(b) ("Program costs" means all reasonable and prudent costs incurred in developing and implementing energy efficiency, conservation, or Class I renewable energy programs approved by the board pursuant to this section. *These costs shall include a full return on invested capital* and foregone electric and gas distribution fixed cost contributions associated with the implementation of the energy efficiency, conservation, or Class I renewable energy programs until those cost contributions are reflected in base rates following a base rate case if such costs were reasonably and prudently incurred.") (emphasis added)

legislature also expressly stated in the CEA that the utilities "shall" receive EE program incentives.[8] In addition, as explained further below, the CEA does not require that penalties be imposed during the "ramp up" phase of the utility programs, which provides the BPU with flexibility in program design.

In implementing the CEA, it also is important to review industry studies of successful utility EE programs. For example, the American Council for an Energy-Efficient Economy ("ACEEE"), a 501(c)(3) organization that conducts EE policy and technical analysis, has been studying state EE programs for several years. The ACEEE studies show the importance of including lost revenue recovery, the amortization of EE investments with a return on those investments, and appropriately designed incentive mechanisms.[9]

Below, the Company sets out its recommendations for lost revenue recovery, amortization, and incentives/penalties. The recommendations are consistent with the CEA and the many industry studies, as noted above, that establish the requirements for successful utility EE programs. Also, as requested by BPU Staff, at the end of the recommendations, the Company comments on the four EE cost recovery scenarios circulated by BPU Staff on December 19, 2019.

<u>Recommendation 1: Provide for Lost Revenue Recovery with a Revenue Decoupling Mechanism</u>

The BPU should implement a decoupling mechanism[10] that allows utilities to recover lost revenues to cover fixed costs. The term "decoupling" refers to severing the link between utility sales and revenues. In practice, this means that the regulatory body periodically "trues up" any difference between a utility's actual sales for a particular year and sales projections submitted by the utility as part of its revenue requirement. This true-up mechanism affects customer rates symmetrically: revenues associated with higher than expected sales are refunded to customers, while revenues associated with lower than expected sales are collected from customers. Providing for revenue decoupling is consistent with the requirements in the CEA and findings of industry studies of successful EE programs.

As noted above, the CEA expressly states that utility EE recovery includes "the revenue impact of sales losses resulting from implementation of the energy efficiency and peak demand

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[8] *See N.J.S.A.* 48:3-87e (2) ("If an electric public utility or gas public utility achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive as determined by the board through an accounting mechanism established pursuant to section 13 of P.L.2007, c. 340 (C.48:3-98.1) for its energy efficiency measures and peak demand reduction measures…").

[9] *See, e.g.*, Maggie Molina and Marty Kushler, *Policies Matter: Creating a Foundation for an Energy-Efficient Utility of the Future*, American Council for an Energy-Efficient Economy ("ACEEE") (June 2015), Available at https://aceee.org/sites/default/files/policies-matter.pdf; and *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities*, ACEE (December 2018). Available at https://aceee.org/sites/default/files/pims-121118.pdf.

reduction schedules."[11] This language in the CEA allows utilities to recover lost revenue, aligning the EE program and utility business models in order to achieve EE reductions.

Industry studies recognize that utility business models discourage utilities from investing in EE.[12] Specifically, while a utility's variable costs change in proportion to sales volume, a utility's short-term fixed costs do not.[13] As a result, a reduction in sales due to EE reduces revenue to a level where the utility is unable to cover fixed costs.[14] Without lost revenue recovery, utilities risk significant earnings loss. A decoupling mechanism aligns the utility business model with EE programs by providing for recovery of the utilities' costs even if sales decline; without such a mechanism, it will be difficult for a utility to recover fixed costs. The ACEEE has concluded that the ability to make up for this lost revenue is an essential component of a robust EE portfolio.[15] In addition, a 2019 study by the National Conference of State Legislatures showed that thirty-one states have implemented revenue decoupling. [16]

The Company recommends that the BPU implement a commonly used decoupling mechanism where a target revenue is established during a utility's base rate case. The difference between a utility's target revenues and its actual revenues is adjusted periodically, and the positive or negative adjustment is passed through a decoupling surcharge. The target revenue is developed in the base rate case after accounting for the utility's expenses, capital investment, and return. The target revenue results from a sales forecast for the rate year multiplied by delivery rates by class to calculate a target revenue level by class. Typically, the sales forecast is the result of negotiated settlements. The parties determine sales in a "normal" weather year by using a rolling average of either the past 20 years, or 10 years, or whatever the parties negotiate as a "normal" weather year.

At the end of each rate year, or more frequently, actual revenues are compared to the target revenue by class and either refunded or charged to the customer class over the following year through a decoupling surcharge. If the under-collection is significantly lower than the target, an annual adjustment may result in rate shock to customers, and negatively affects the utility's cash flow. Therefore, the utility should be allowed to adjust the decoupling charge more frequently if it appears that actual revenues are significantly below the target.

The Company cautions the BPU against adopting a Lost Revenue Adjustment Mechanism, or "LRAM." An LRAM attempts to tie lost revenue directly to the efficiency measures and

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[11] *N.J.S.A.* 48:3-87.9e (1).
[12] *See* Maggie Molina and Marty Kushler, *Policies Matter: Creating a Foundation for an Energy-Efficient Utility of the Future*, ACEEE (June 2015).
[13] *Id.*
[14] *Id.*
[15] *See, e.g.*, the ACEEE Scorecard, page 14.
[16] *State Policies for Utility Investment in Energy Efficiency*, page 3, the National Conference of State Legislatures (April 2019), Available at http://www.ncsl.org/Portals/1/Documents/energy/Utility_Incentives_4_2019_33375.pdf?ver=2019-04-04-154310-703310-703

eliminates other factors that may reduce energy use (such as weather or new Distributed Energy Resources). The LRAM continues the link between utility profit and sales, and as a result will not eliminate the disincentive, noted by the ACEEE, for a utility to invest in EE. For example, in a recent study, the National Conference of State Legislatures concluded that LRAMs remove the EE disincentive of unrecognized revenue, but they continue to promote increased energy sales for higher profits.[17] Also, unlike a decoupling mechanism, utility sales are not adjusted if utility sales exceed estimated savings or if utility sales are below projections. An LRAM only allows upward adjustments to recover EE costs but not downward adjustments when revenues exceed expectations.[18] As a result, the LRAM produces upward pressure on utility rates.[19] An LRAM also requires a much more complex evaluation, measurement and verification process than a revenue decoupling mechanism, in order to calculate actual energy savings achieved.[20] The LRAM process is not only more complex than decoupling, but also increases the potential for conflict over the LRAM calculations.[21]

<u>Recommendation 2: Provide for amortization and recovery of program costs</u>

RECO recommends that utility EE investments be amortized by the utility with a return on the EE investment, as required by the CEA. In a recent study the ACEEE found that the exclusion of a return on EE programs is a barrier to robust EE programs.[22] The ACEEE explained that investments in EE compete with other utility capital investment,[23] and without a return on EE investments, investments in EE reduce the utility's earnings.[24] Therefore, the exclusion of a return on EE investment creates a disincentive for utility investment in EE. Conversely, including a return on EE investment places EE investments on a level playing field with traditional utility investments, and removes a barrier to a robust EE program. The return on EE investments also changes the level of priority given to EE by the utility, making EE more comparable to the utility's traditional rate-of-return treatment for supply-side investments.[25] Similarly, to remove the disincentive to investment in EE, the carrying charge rate should be the utility's pre-tax overall Weighted Average Cost of Capital ("WACC"), as established by the BPU in the utility's last base rate case. Using the utility's WACC places utility EE and non-EE investments on an equal footing, and therefore eliminates the utility's disincentive to invest in EE.

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[17] *Id.*
[18] *Id.*
[19] *Id.*
[20] *Lost Margin Recovery*, ACEE (2017). Available at https://aceee.org/sector/state-policy/toolkit/utility-programs/lost-margin-recovery
[21] *Id.*
[22] *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities*, ACEEE (December 2018). Available at https://aceee.org/sites/default/files/pims-121118.pdf
[23] *Id.*
[24] *Id.*
[25] *Id.*

Additionally, RECO recommends that the costs of EE investments be amortized over the average life of a portfolio of EE investments or similar period (*e.g.*, a ten-year period of amortization).[26] Amortization eliminates the impact on customers, or rate shock, resulting when program costs are expensed in the year that costs are incurred. Also important, amortization allows utilities that are rapidly ramping up their EE investments to spread those costs over the entire amortization period, leveling out the costs of these large EE investments.

Amortization also is more equitable because customers contributing to program costs benefit from the program. If program costs are expensed, only customers in the utility's service territory when the costs are incurred will pay for the program. As a result, customers who leave the service territory during the life of a program will not receive all of the benefits, even though these customers contributed, through utility charges, to all of the costs. Similarly, customers who move into the service territory after the EE costs are expensed will benefit without contributing to the costs of the program. A 2018 study by the ACEEE confirmed that EE programs that amortize EE investment with a return are more equitable, encourage utility EE investment, and result in desirable EE outcomes.[27] The 2018 ACEEE study also concluded that amortization allows utilities to rapidly ramp up EE investment but spread the costs over the entire period that customers benefit from the investment.[28] In short, the cost recovery mechanism that is the most just and reasonable for customers is amortization over the average life of the portfolio of EE programs, or, as recommended by RECO, a proxy of ten years for the average life of an EE portfolio of programs.[29]

Some stakeholders in this BPU proceeding have suggested that the utility should not earn a return, or should earn a reduced return, because the addition of a decoupling mechanism reduces the utility's risk. However, a decoupling mechanism still leaves a utility with both business and financial risk,[30] and therefore the addition of a decoupling mechanism should not reduce the Company's return. For example, a utility's sales may increase (*e.g.*, due to hotter than forecasted weather).[31] However, under a decoupling mechanism, the utility will return to customers the revenues associated with these increased sales, rather than using such revenues to cover any unexpected increased costs.[32] As a result, the Company still experiences risk, even with a decoupling mechanism.[33] An ACEEE review of state programs concluded that in the majority of state programs where a decoupling mechanism was implemented, the state program did not

[26] The Company recommends an amortization period of ten years as a proxy for the average life of a portfolio of EE programs, which both simplifies the calculation and avoids extended litigation over the calculation of the average life of EE programs and EE program portfolios.
[27] *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities*, pp. 7-8, ACEEE (December 2018). Available at https://aceee.org/sites/default/files/pims-121118.pdf
[28] *Id.*
[29] See footnote 25 above.
[30] *A Decade of Decoupling for US Energy Utilities: Rate Impact, Designs, and Observations*, pages 14-17, ACEEE (May 2013). Available at https://aceee.org/files/pdf/collaborative-reports/decade-of-decoupling.pdf
[31] *Id.*
[32] *Id.*
[33] *Id.*

reduce the utility's return.[34] In addition, a recent empirical study of the impact of utility decoupling mechanisms in financial markets confirmed that decoupling did not lead to a decrease in the utility's cost of capital.[35]

Recommendation 3: Incentives and Penalties

RECO recommends that the BPU provide for incentives early in the EE program as they are critical to the success of EE programs during the "ramp-up" period. After allowing for utility EE programs to ramp-up, the BPU can then revisit the implementation of penalties. The CEA provides for both incentives and penalties,[36] but does not require that penalties and incentives be implemented for the same period. CEA Section e (2) on incentives states:

> If an electric public utility or gas public utility achieves the performance targets established in the quantitative performance indicators, the public utility shall receive an incentive….

CEA Section e (3) on penalties states:

> If an electric public utility or gas public utility fails to achieve the reductions in its performance target established in the quantitative performance indicators, the public utility shall be assessed a penalty….

In addition, the CEA sections that address utility cost recovery[37] and Quantitative Performance Indicators[38] ("QPIs") do not require that the BPU impose incentives and penalties for the same period.[39] By separating the award of incentives from the imposition of penalties the CEA provides the BPU with the authority and flexibility to implement incentives in the first year of the utilities' EE programs, and delay penalties until the utilities have ramped up their EE programs. The CEA does not require that penalties and incentives occur in the same year of the utilities' EE programs.

Incentives need to be in place at the beginning of the EE program to encourage the utility to meet and even exceed its energy reduction target. RECO's parent company, Orange and Rockland Utilities, Inc., has experience in New York implementing EE programs with linearly scaled incentives. In order to determine appropriate incentives, the New York Public Service

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[34] *Id.*
[35] *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utility: An Empirical Investigation*, p. 18, The Brattle Group (March 2014). Available at http://files.brattle.com/files/6081_effect_of_electric_decoupling_on_the_cost_of_capital.pdf
[36] *See* CEA e (2) and e (3).
[37] *N.J.S.A.* 48:3-87.9e (1).
[38] *N.J.S.A.* 48:3-87.9c.
[39] *N.J.S.A.* 48:3-87.9e (1) states that the utilities annually shall file a petition with the BPU "for cost recovery of the programs, including any performance incentives *or* penalties….) (emphasis added). Also, *N.J.S.A.* 48:3-87.9c states that in developing QPIs for utility performance, the BPU is to establish factors "to ensure that the public utility's incentives *or* penalties" are based on performance." (emphasis added).

Commission ("NYPSC") established a target MWh reduction and a $/MWh incentive. For example, if target achievement is greater than 80% of the target, then an incentive is earned. For achievement of 100% of the target, 100% of the incentive is earned, and for achievement of 90%, 50% of the incentive is earned. In addition, for achievement between 70%-80%, no incentives or penalties are imposed (*i.e.*, dead band). For achievement between 50%-70% penalties would be imposed with any achievement below 50% at 100% of the penalty. Achievement at 60% would incur 50% of the penalty.

Another option for designing incentives would be to implement a basis point method wherein incentive targets are established using basis points of return on common equity with higher basis point incentives for greater energy savings. This method of allocating basis points to performance has proven successful in New York's Reforming the Energy Vision ("REV") proceeding. An agreed upon number of basis points would be allocated to the performance of the overall electric or gas portfolio with breakpoints that align minimum, midpoint, and maximum achievement. For example, 30 basis points would be allocated to the minimum target, 60 basis points to the midpoint target, and 90 basis points to the maximum target. Basis points will be established in the utilities most recent base rate cases and will vary by utility.[40]

The NYPSC highlighted the importance of financial incentives in its successful EE programs in 2016, by stating:

> Aligning financial incentives with policy goals is the best way to assure the furtherance of [New York's energy efficiency] goals. Where possible, markets and positive financial incentives – rather than direct regulatory mandates with negative consequences - should be the primary drivers of the countless implementation actions, decisions, and initiatives needed to transform the industry. We therefore determine that the direction of rate regulation is towards aligning financial incentives with REV objectives by combining discrete reforms to conventional ratemaking with new earning opportunities that better align the utility and consumer economic welfare interests.[41]

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[40] A basis point of return on common equity is calculated by taking the rate base balance, multiplying by the equity ratio, dividing by the retention factor (*i.e.*, the adjustment for taxes and uncollectibles) and multiplying by the basis point target. Using numbers from Schedule A of RECO's most recent rate order (BPU Docket No. ER16050428) as an illustration, the value of 10 basis points at that time was approximately $150,000 (rate base of $178,727,000 x equity ratio of 49.70% ÷ retention factor of .5906 x 10 basis points, or 0.1%)

[41] Case 14-M-0101, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, issued May 19, 2016.

As a result of this policy direction, New York State is well on its way to reducing energy needs by 185 TBtu through 2025, reducing greenhouse gas emissions by 40 percent below 1990 levels in 2030, and sourcing 50 percent of the State's electricity from renewable resources by 2030.[42] Imposing penalties too early in the EE programs will undermine the achievement of the energy savings New Jersey needs. RECO recommends that no penalties be imposed during the utility ramp up period. After the EE programs have been approved by the BPU, the utilities will initiate their EE programs, which may require retaining vendors, customer education, and marketing. During this ramp up period the utilities and the BPU will learn where adjustments should be made in the EE programs. Imposing penalties during the ramp up period inhibits the long-term growth and sustainability of a robust EE program portfolio. For example, penalties imposed too early limit the utilities' ability to adjust EE programs if customers respond favorably to some EE measures but do not respond favorably to other EE measures. This could inhibit the ability to achieve the expected energy reductions. The development and implementation of a successful EE portfolio includes time and effort to include the right mix of measures, level of incentives, and measurement and verification. This requires that programs be dynamic and designed to incorporate market drivers and new technologies that benefit customers well into the future. RECO notes that the ACEEE has recognized that EE programs require a ramp up period, particularly where there is regulatory lag in examining the EE programs.[43]

<u>Cost Recovery Stakeholder Hypothetical Scenarios</u>

In an email circulated on December 19, 2019, BPU Staff requested comments on four specific cost recovery scenarios in order "to further clarify stakeholder input on cost recovery constructs." In its comments above, the Company has addressed certain of the elements of each of these four scenarios. Accordingly, the Company presents certain of its comments below in a summary form.

<u>Scenario 1</u>

In this scenario, the costs of a utility's EE program would be expensed, with a rate cap at two percent of a customer's bill, and with no revenue decoupling. The carrying cost for any under/over recovery would be at the T-bill rate. Incentives and penalties would be tied to a percentage of savings.

This scenario is least likely to drive the robust EE investment necessary to meet the CEA's ambitious goals. By not providing a return on investments, this scenario disadvantages EE

[42] "About Reforming the Energy Vision," NYPSC (February 2017). http://www3.dps.ny.gov/W/AskPSC.nsf/96f0fec0b45a3c6485257688006a701a/71bf9b959e12f08a85257fc5005e0679/$FILE/2017%20REV%20info%20sheet%20draft%20FINAL%202-10-17.pdf
Available at http://www3.dps.ny.gov/W/AskPSC.nsf/96f0fec0b45a3c6485257688006a701a/71bf9b959e12f08a85257fc5005e0679/$FILE/2017%20REV%20info%20sheet%20draft%20FINAL%202-10-17.pdf

[43] *Energy Efficiency Resource Standards: A New Progress Report on State Experience*, page 24, ACEEE (April 2014). Available at https://aceee.org/sites/default/files/publications/researchreports/u1403.pdf

investment as compared to traditional utility infrastructure investment. Further, as explained earlier in these Comments, expensing the costs of EE programs will place upward pressure on utility rates. While this scenario seeks to address this inevitability by imposing a rate cap, this further adversely affects utilities and their customers by limiting the amount utilities can invest in energy efficiency programs. Additionally, utilities will be prevented from recovering their expenditures in a timely fashion, while recovering minimal carrying costs (ten-year T-bill rates are currently at 1.83%) on their unrecovered balances. The lack of a revenue decoupling mechanism further disadvantages utilities for the reasons discussed above. In summary, utilities would be financing EE programs that cannibalize their own sales, while also being unable to recover the full costs of their efforts in a timely fashion.

Scenario 2

In this scenario, the costs of a utility's EE program would be amortized by means of a weighted-life recovery, with no rate cap, and with full revenue decoupling. Utilities would receive a return on their EE investments set at their WACC. The carrying cost for any under/over recovery would be at the T-bill rate plus 60 basis points. Incentives and penalties would be at a Fixed Dollar Incentive/ Fixed Dollar Penalty (thresholds related to QPI performance).

For the reasons discussed above, among the four scenarios, Scenario 2 this scenario will best encourage and facilitate the robust utility EE investment necessary to meet the CEA's ambitious goals. As noted above, the Company proposes that amortization occur over a ten-year period.

Scenario 3

In this scenario, the costs of a utility's EE program would be amortized by means of a weighted-life recovery, with no rate cap, and with limited revenue decoupling. Utilities would receive a return on their EE investments set at their WACC. The carrying cost for any under/over recovery would be at the two-year T-bill rate. Incentives and penalties would be at a percent of return (weighted by QPI performance).

This scenario is a limited variation of Scenario 2. BPU Staff has not divulged the nature of the limitation on revenue decoupling. For the reasons discussed above, limitations on revenue decoupling will impede the achievement of EE goals and therefore should be avoided. As to incentives/penalties, the Company favors the use of specific dollar amounts for the sake of clarity and simplicity. Any incentives/penalties should be directly related to the utility's performance.

Scenario 4

In this scenario, the costs of a utility's EE program would be amortized over ten years, with a three percent rate cap, and with no revenue decoupling. Utilities would receive a return on their EE investments set at their WACC less 200 basis points. The carrying cost for any under/over recovery would be at the T-bill rate plus 60 basis points. Incentives and penalties would be at a percent of return (weighted by QPI performance).

As noted above, the Company is agreeable to amortization over ten years. Reducing the utilities' return on their EE investments, rejecting revenue decoupling, and linking incentives/penalties directly to a utility's return will hinder the success of EE programs for the reasons discussed above.

Conclusion

The Company's recommendations above reflect the legislative intent of the CEA and the findings of studies on successful EE programs that will result in New Jersey successfully achieving its energy reduction goals. In order to implement the CEA as the legislature intended, and in order to achieve or even exceed energy reduction targets, the BPU should establish a cost recovery framework that supports energy reduction. That cost recovery framework, as explained in these Comments, permits the following: the recovery of lost revenues through a decoupling mechanism; the amortization of EE investments with a return on EE investments at the utility's WACC; and establishes appropriate incentives during the EE program's ramp-up period without imposing penalties during the ramp up period. The Company looks forward to continuing to work with the BPU and stakeholders to develop a successful EE program in New Jersey.

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Deborah M. Franco, Esq.
Director, Regulatory Affairs Counsel

January 3, 2020

VIA UNITED PARCEL SERVICE & ELECTRONIC MAIL
(EnergyEfficiency@bpu.nj.gov)

Honorable Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 S. Clinton Ave., 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: <u>December13, 2019 Energy Efficiency Technical Meeting - Cost Recovery</u>

Dear Secretary Camacho-Welch:

On December 13, 2019 New Jersey Board of Public Utilities Staff ("BPU Staff") held an energy efficiency stakeholder technical meeting focused on cost recovery ("December 13 Meeting"). Subsequent to the December 13 Meeting, BPU Staff provided four (4) cost recovery scenarios for stakeholder comment. BPU Staff requested that written comments be submitted by January 3, 2020. These comments are being submitted on behalf of South Jersey Gas Company ("SJG") and Elizabethtown Gas Company ("ETG") (collectively, the "Companies") in accordance with the BPU Staff request.

SJG and ETG remain committed to supporting the State's energy efficiency goals and appreciate the key role they play in achieving the energy consumption reduction targets contained in the New Jersey Clean Energy Act of 2018 (the "Act"). The Companies have been regularly engaged in the promotion of energy efficiency in New Jersey for many years with much success and will continue to support programs that encourage a reduction in energy consumption.

As it relates to cost recovery, through these comments, the Companies incorporate and support by reference the comments submitted by Gabel and Associates, Inc., as well as those submitted by the New Jersey Utilities Association. Under the Act (<u>N.J.S.A.</u> 48:3-87.9.e.(1)), utilities are entitled to recover on a full and current basis all reasonable and prudent energy efficiency program costs, including a return of and on capital investments, as well as the impact of lost sales revenues. It is vital that energy efficiency cost recovery constructs are designed in a manner consistent with the robust goals set forth in the Act. This can only be achieved by amortizing program costs over the weighted-average measure life of the EE portfolios, decoupling utility distribution revenues from sales volumes, and implementing incentive and penalty structures that are simple and provide clear signals to maximize energy savings.

SJG and ETG appreciate the opportunity to submit these comments and look forward to continued collaboration with all stakeholders.

Respectfully yours,

Deborah M. Franco

/DMF

January 3, 2020

Secretary of the Board of Public Utilities
Attn: Aida Camacho-Welch
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350

Re: New Jersey Energy Efficiency Transition Technical Working Group Meeting II for Cost Recovery, December 13, 2019, Written Comment

Uplight appreciates the opportunity to share our perspective and expertise with the New Jersey Board of Public Utilities ("BPU") on program cost recovery under the Clean Energy Act ("CEA") through both in-person participation and follow up through these written comments. While our most substantive input was included in our previous round of comments submitted on November 14, 2019 (including the report from The Brattle Group, *Energy Efficiency Administrator Models - Relative Strengths and Impact on Energy Efficiency Program Success*) we did want to supplement that input with the following.

Correcting Misperceptions on Performance of Decoupling

During the technical working group meeting on December 13th, a few commenters claimed that decoupling of any kind would result in a "death spiral" in New Jersey. These assertions are not supported by data. We supply to the Board of Public Utilities the attached report conducted by The Brattle Group, *Energy Efficiency Administrator Models: Relative Strengths and Impacts on Energy Efficiency Program Success*. This research shows that energy efficiency programs, as measured by overall savings, adjusted for per capita energy efficiency spending, **perform best when both decoupling and performance incentive mechanisms are in place.**

Table 5: Top and Bottom 10 Performing States with Respect to Average Annual EE Savings (%)

Rank	State	Admin Type	Ave EE Savings %	Max EERS Goal %	Incentive Types
	Top 10 Performers				
1	Rhode Island	Utility	3.0%	2.6%	Decoupling + PIM
2	Massachusetts	Utility	2.7%	2.9%	Decoupling + PIM
3	Vermont	Third Party	2.6%	2.2%	Decoupling + PIM
4	California	Hybrid	1.8%	1.2%	Decoupling + PIM
5	Connecticut	Utility	1.6%	1.5%	Decoupling + PIM
6	Hawaii	Third Party	1.4%	2.0%	Decoupling + PIM
7	Washington	Utility	1.4%	1.5%	Decoupling + PIM
8	Arizona	Utility	1.3%	2.5%	LRAM + PIM
9	Michigan	Hybrid	1.3%	1.0%	PIM Only
10	Maine	Government	1.3%	2.4%	Decoupling Only
	Bottom 10 Performers				
42	Tennessee	Utility	0.2%	0.0%	None
43	Texas	Utility	0.2%	0.1%	PIM Only
44	Delaware	Government	0.1%	0.0%	None
45	Florida	Utility	0.1%	0.0%	None
46	Virginia	Utility	0.1%	0.0%	LRAM Only
47	Louisiana	Utility	0.1%	0.0%	LRAM + PIM
48	Alabama	Hybrid	0.1%	0.0%	None
49	North Dakota	Utility	0.0%	0.0%	None
50	Alaska	Government	0.0%	0.0%	None
51	Kansas	Utility	0.0%	0.0%	LRAM

Notes and sources: Admin type: The Brattle Group, based on Richard Sedano, *Who Should Deliver Ratepayer-Funded Energy Efficiency? A 2011 Update*, RAP (2011); with verification and adjustment based on review of ACEEE State Database. EE savings and max. EERS goal: ACEEE State Energy Efficiency Scorecard (2012–2017). Incentive types: analysis of the ACEEE State Energy Efficiency Scorecard (2016–2017) and SNL RRA Regulatory Focus (2016–2017).

Source: *Energy Efficiency Administrator Models: Relative Strengths and Impacts on Energy Efficiency Program Success*. Prepared for Uplight by Sanem Sergici and Nicole Irwin, The Brattle Group, November 2019

Decoupling and amortization are broadly accepted by the energy efficiency industry writ large. In fact, when we speak to the regulators and staff from leading states, they are surprised that this is even an outstanding question in New Jersey.

Feedback on Cost Recovery Scenarios

We would like to echo the comments of our trade association Energy Efficiency Alliance of NJ (EEA-NJ) in saying that of the scenarios presented at the "Energy Efficiency Technical Meeting II" in

Trenton on December 13th, Scenario 3 is the closest to the optimal scenario; however, **instead of limited decoupling, the BPU should implement full decoupling.** EEA-NJ's comments on this matter further details the reasons why.

In addition to comments from EEA-NJ, we would like to take the opportunity to dig deeper on the question of incentives. Because this is a new paradigm for investment by the utilities, we encourage the BPU to recognize that incentives for strong performance should be significantly attractive enough to catalyze new and innovative investments. As such, if the utilities exceed the performance targets across potential Quantitative Performance Indicators (QPIs) they should be able to recover their investments at a greater percentage than their weighted average cost of capital (WACC.) Our understanding is that QPI development will be addressed in future stakeholder meetings, at which point we will share additional thoughts about the design of the incentive mechanisms.

Thank you once again for the opportunity to share our insights and perspectives. We look forward to continuing these conversations as part of the BPU's continued efforts to develop a sustainable and cost-effective energy system for the people and businesses of New Jersey.

Sincerely,
Tanuj Deora
Vice President, Market Development and Regulatory Affairs
Uplight