Do Electric-Resource Portfolio Managers Have an *Inherent* Conflict-of-Interest with Energy Efficiency?

Devra Bachrach and Sheryl Carter, Natural Resources Defense Council

ABSTRACT

Sweeping claims are made about the presence or absence of conflicts-of-interest relative to energy efficiency faced by electric-resource portfolio managers, including investor-owned utilities, publicly-owned utilities, and Community Choice Aggregators. This paper examines the incentives and disincentives faced by these different types of portfolio managers, and finds that there is nothing *inherent* about the conflict-of-interest faced by portfolio managers. All types of portfolio managers, whether public or private, can face conflicts-of-interest when cost recovery and profits are tied to sales volume, but this problem can be solved and this paper provides the details. This paper also reviews the status of efforts around the country to implement policies that remove any disincentive for investments in cost-effective energy efficiency and distributed resources. While we focus here on providers of electricity service, natural gas providers face the same disincentive, and we briefly discuss progress in this area.

As the procurement options for portfolio managers have increased over the past decade, the incentives they face for procuring one type of resource over another have become more complex. Not only must they choose between supply- and demand-side resources, but between various types of owned and contracted resources as well. In order to create a more level playing field among all competing resources, and to allow the most cost-effective resources to prevail, the portfolio manager needs to have balanced incentives for all these types of resources. This paper looks at how to structure incentives for energy efficiency in the context of an entire portfolio of resources, drawing heavily on California's recent experience.

The Return of Electric-Resource Portfolio Management

Recent turmoil in the electricity industry has focused attention once again on one of the crucial responsibilities of utilities: electric-resource portfolio management. Effective portfolio management requires a fully integrated approach to identify system, statewide policy and customer electric service needs and select demand- and supply-side alternatives to meet those needs in a manner that results in a portfolio that minimizes total cost, environmental impacts, and has an acceptable level of risk (Harrington et al. 2002).

The failure to ensure responsible management of a resource portfolio to meet customer needs was a critical piece missing in California's effort to create a competitive market in electricity. Rather than proactively establish a process and framework for responsible portfolio management by the utilities, policy makers created a system that left all of California's electricity demand dependent on a volatile spot market and abandoned any focus on meeting long-term customer needs in an affordable, reliable and environmentally responsible manner. Abandoning this central policy direction has been almost universally condemned as a significant contributor to the higher costs for customers and society that California saw during the crisis. The California Legislature and Public Utilities Commission seized the opportunity to begin rectifying this gap in the electricity framework in California, by recognizing the significant potential benefits to customers and society in general that responsible portfolio management and oversight offers.

California provided perhaps the most dramatic example of the need for responsible portfolio management, but the state is not alone. Legislatures and regulators around the country have gained a newfound appreciation for the importance of portfolio management. States that chose not to pursue restructuring, as well as those that pursued it aggressively, are in the process of strengthening utilities' fundamental responsibility as portfolio managers to make long-term investments to meet customers' needs and establishing policy frameworks to guide that investment process.

Who Is Responsible for Portfolio Management?

Throughout the United States, the most common electric-resource portfolio manager is the hometown utility. This includes publicly-owned utilities that are governed by local boards, as well as investor-owned utilities that are regulated by state Public Utility Commissions. These boards and regulators are responsible for guiding the utilities' portfolio management and long-term investment activities. As a practical matter, however, many states' boards and regulators give little guidance to utilities with regard to the goals and objectives of truly comprehensive, integrated resource portfolio management.

In states that have restructured their electricity industry and established a competitive retail market, Energy Service Providers (ESP) also perform the portfolio management function on behalf of their customers, while management of the distribution system remains with the utility. Most ESPs are required to sign up each individual customer that they serve; however, a few states, including California, Massachusetts, Ohio, and Rhode Island have enacted legislation that enables local governments to become portfolio managers by providing energy services to utility customers in their jurisdictions on an "opt-out" and aggregated basis. These are commonly known as Community Choice Aggregators (CCA). Under this model, local governments can establish themselves as the default portfolio manager for all customers within their jurisdiction, while allowing individual customers to opt-out and return to the utility or another ESP.

In California, the Legislature passed Assembly Bill 117 in late 2002, permitting cities and counties to become Community Choice Aggregators and to provide energy services for customers in their respective jurisdictions (CPUC 2003, 1). No CCAs have been formed in California, although several cities are giving it serious consideration. In Massachusetts, the only CCA we are aware of is the Cape Light Compact, which serves about 180,000 customers (Cape Light Compact 2004). As of March 2002, there were about 600,000 customers in 158 municipalities in Northern Ohio who had joined municipal aggregations (Maine Public Advocate Office 2002, 3).[1] Two of the largest are the city of Parma and the Northeast Ohio Public Energy Council (NOPEC). NOPEC is the nation's largest CCA, representing 112 cities and townships with 450,000 customers in the Cleveland metro area (NOPEC 2004).

All Portfolio Managers Can Face a Conflict-of-Interest with Energy Efficiency

Any electric-resource portfolio manager's enthusiasm for pursuing cost-effective energy

[1] For a list of all communities participating in community choice aggregation, see www.ohioelectricchoice.com/residential/govagglist.asp.

efficiency and other demand reduction resources that reduce the volume of electricity sold, while still meeting or exceeding the customers' energy service needs, will depend on the incentives that manager faces. The incentive structure under which a portfolio manager operates (meaning the collective impact of the incentives and disincentives they face) is a matter of utmost importance, because it guides the portfolio manager's decision-making and ultimately their impact on society and the environment. Indeed, one of the fundamental purposes of the regulators and boards is to create an appropriate incentive structure to help align the portfolio manager's decisions and investments with the public interest.[2]

Sweeping claims are often made about the presence or absence of conflicts-of-interest relative to energy efficiency faced by various portfolio managers, including investor-owned utilities, publicly-owned utilities, and Community Choice Aggregators. In this section, we discuss how conflicts-of-interest arise for all types of portfolio managers, whether public or private, and how these conflicts can be removed.

The Problem with Traditional Regulation of Portfolio Managers

Under traditional regulation in the United States, utility regulators or publicly-owned utility directors establish an electricity sales forecast, determine an authorized revenue requirement (which includes both fixed and variable costs of electricity production), and set rates by dividing the revenue requirement by the sales forecast.

But once the rates are set, which usually occurs only once every few years, the utility's *actual revenue* depends in large part on the volume of electricity sold (Eto, Stoft & Belden 1994). This creates a problem because studies have shown that the volume of electricity sales is very poor at explaining the magnitude of fixed-costs (Eto, Stoft & Belden 1994; Van Lierop 2004, 13). If actual annual electricity sales diverge from the forecast used to set the authorized revenue requirement, the utility will either under- or over-recover the fixed-cost element of its revenue requirement.[3]

Thus, traditional regulation links the utility's financial health to the volume of electricity sold, providing a disincentive to invest in – or a so-called "conflict of interest" with – energy efficiency, distributed generation, and other demand-side resources that reduce electricity sales. This can prevent utilities from taking advantage of cost-effective resources that can minimize the long-term cost of providing service. It also impedes potentially crucial utility support for energy-efficiency standards and other policies that serve societal interests and reduce electricity needs without requiring *any* direct utility investment.

While this problem is most often discussed in the context of investor-owned utilities, publicly-owned portfolio managers, including municipal utilities and CCAs, can face equivalent conflicts-of-interest concerning energy efficiency.

Publicly-owned utilities. Publicly-owned utilities, such as the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD), are

[2] In the case of publicly-owned portfolio managers, the "incentive structure" established by the board means the collective incentives or disincentives the utilities' management faces to maintain the utilities' financial health and to provide any transfer payments to fund essential city services.

[3] For a simple numerical illustration of the problem utilities face under this outmoded form of price regulation and the best solution to it, see Bachrach, Ardema and Leupp (2003).

governed by local boards and are generally not regulated by Public Utilities Commissions.[4] Although municipal utilities are public entities, they suffer from the same "conflict of interest" with energy efficiency and distributed generation that privately-owned utilities face under traditional regulation.

This conflict arises because once the board sets a utility's rates, the utility's ability to meet its financial obligations is entirely dependent on meeting or exceeding expected sales volumes. And although they don't have shareholders, customer-owned utilities have comparable needs for fixed cost recovery and are often counted on to underwrite crucial city services;[5] when retail sales drop, these objectives are jeopardized. Although they face comparably strong disincentives to invest in energy efficiency, no publicly-owned utilities have yet enacted the policy solutions discussed below, despite strong urging from public interest organizations.

Community choice aggregators. CCAs are similar to publicly-owned utilities, except CCAs do not own distribution and transmission infrastructure and instead act as the portfolio manager while the local utility continues to provide distribution service. CCAs make resource commitments as well as other investments in order to meet the needs of their customers. Many of these commitments result in the need for fixed-cost recovery; these fixed-costs could include debt service (for example, to cover the financing costs of a power plant), customer service and billing infrastructure, take-or-pay contracts, etc. Clearly, CCAs will have financial obligations to meet and their enthusiasm for energy efficiency investments will depend in part on their mechanisms for determining revenues and setting rates. If CCAs follow the tradition in the utility industry of tying their cost recovery to throughput, then they will be faced with the same disincentive to invest in energy efficiency and other distributed resources as they seek to meet their financial obligations. Of course, since the local utility still provides distribution service to CCA customers, it is still important to eliminate the utility's conflict-of-interest with energy efficiency, so that the CCA and the distribution utility are not left working at cross-purposes.

To date, no CCA that we are aware of has corrected the disincentive to invest in energy efficiency that arises when revenues are tied to sales, nor has a CCA invested in energy efficiency through its procurement fund as the least-cost option to meet its customers' energy service needs. In the case of Cape Light Compact (Compact) in Massachusetts, the CCA essentially acts as an intermediary between its customers and an ESP (Cape Light Compact 2004; Downey 2004). The ESP is thereby the portfolio manager for Compact, but the ESP's revenues are based on the volume of kWhs sold, and not surprisingly, the ESP has not invested in energy efficiency (Downey 2004). Compact implements energy efficiency programs in its territory funded by the state's limited mandatory public benefits charge on all utility bills, but does not invest any additional funds to meet its customers' needs in a least-cost manner (Cape Light Compact 2003; Downey 2004). The Northeast Ohio Public Energy Council (NOPEC), the largest CCA in the country, similarly acts as an intermediary between its customers and an ESP (NOPEC 2004). NOPEC negotiated a contract with an ESP that provides customers with a

[4] Exceptions do exist; for example, Vermont's municipal utilities are regulated by the Public Service Board.

[5] For example, LADWP's annual transfer to the City of Los Angeles is a very important source of revenue for the City; in the last fiscal year, LADWP's transfer of more than $160 million was the seventh largest source of revenue for the City, comprising 5% of its total revenues. Several other customer-owned utilities in California transfer between 5% and 12% of electric revenues to their respective cities, providing between 6% and 16% of the cities' general fund revenues (Davis 2004). These cities also collect utility user taxes, ranging from 5% to 7% of revenues (Davis 2004). The national average for transfers from customer-owned utilities to cities is 5.7% of the utility's operating revenues (Silverstein 2004).

certain percentage off the default utility price (NOPEC 2004). To our knowledge, NOPEC does not invest in energy efficiency to provide least-cost energy services to its customers.

The Solution: Eliminating Disincentives for Energy Efficiency

Environmental and consumer organizations have long advocated policies that remove this disincentive to encourage policies and investments that promote environmentally superior resource alternatives such as energy efficiency. The solution is clearly summarized in the joint recommendation of the Natural Resources Defense Council and the Edison Electric Institute to the National Association of Regulatory Utility Commissioners in November 2003: "To eliminate a powerful disincentive for energy efficiency and distributed-resource investment, we both support the use of modest, regular true-ups in rates to ensure that any fixed costs recovered in kilowatt-hour charges are not held hostage to sales volumes." (Owens and Cavanagh 2003).

This solution has been successfully implemented by a number of regulators to eliminate their utilities' incentives to increase electricity sales in order to increase profits (Carter 2001; Eto, Stoft and Belden 1994; Marnay and Comnes 1990). This mechanism also protects the direct financial incentive for customers to conserve by allowing the Commission or Board to retain volumetric pricing, where the customer pays for each kWh of electricity used, instead of raising the fixed charge on customer bills to cover the utility's fixed costs.

Creating an appropriate incentive structure for the portfolio manager is of paramount importance regardless of who actually administers energy efficiency programs.[6] The importance is self-evident if the portfolio manager itself administers the programs. But it is also critical if another entity administers the programs, since the portfolio manager will continue to interact with its customers and policymakers on energy matters. If the portfolio managers' incentives are misaligned, they could potentially be left working at cross-purposes with the efficiency programs. Indeed, the experience of independent administrators of energy efficiency programs has confirmed the importance of getting the portfolio manager's incentives right under any administrative model.[7]

Status of Efforts to Eliminate Disincentives for Energy Efficiency Investments

California was one of the first states to recognize the problem traditional regulation created for investments in energy efficiency. The state began using mechanisms to decouple the regulated utilities' revenues from sales in 1982 (Marnay and Comnes 1990). Regulators in several other states, including Oregon, Washington, New York and Maine have also adopted some form of "decoupling" mechanism over the last two decades (Carter 2001). A strong trend in that direction was interrupted in the mid-1990s by a stampede toward an industry restructuring

---

[6] The electric-resource portfolio manager makes short- and long-term investments and assembles a portfolio of resources to meet its customers' overall energy service needs. The administrator of the energy efficiency programs oversees the implementation of the programs and/or contracts with other entities to implement the programs.

[7] For example, New York transferred responsibility for administration of energy efficiency programs to the New York Research and Development Authority (NYSERDA). But with the utilities' cost recovery and profits tied to sales volume, the utilities have actively opposed energy efficiency standards as well as continuation of the energy efficiency programs. In other states, where the utilities have not actively opposed the programs or standards, in some cases they have not been cooperative or particularly helpful to the administrator. In addition, the utilities do not invest additional procurement funds beyond the limited public benefits funds to capture all cost-effective energy efficiency resources.

model that denied utilities any substantial role in resource planning or investment. On that theory, there was no reason to worry about utilities' energy efficiency incentives because utilities would be transferring their resource management responsibilities to unregulated participants in wholesale and retail electricity markets.

The Western electricity crisis of 2000-2001 discredited that model, and as states seek to learn from the mistakes that led to the crisis, there is renewed focus on the need for effective portfolio management as well as decoupling policies that free utilities to plan for investment in the most cost-effective resources, including energy efficiency. Since the end of the crisis, regulators in states including California, Oregon, New York, Washington, and Idaho, have either implemented or are looking at implementing decoupling policies.

California

In early 2001, as California was digging its way out of the electricity crisis, the Legislature enacted Assembly Bill 29x, requiring the Public Utilities Commission to once again break the link between the utilities' revenues and sales.[8] The Commission is now in the process of implementing this policy in each of the utilities' general rate cases (GRC), as we discuss below.[9] Parties to the GRCs have strongly supported the implementation of these decoupling mechanisms. We expect the Commission to finish removing any remaining disincentives for utility investments in energy efficiency this year.

Pacific Gas & Electric (PG&E). In September 2003, PG&E reached a settlement agreement with parties in its general rate case, which included a new revenue decoupling mechanism to remove the disincentive to invest in energy efficiency (PG&E et al. 2003). The settlement agreement states that "the Distribution Revenue Adjustment Mechanism (DRAM) and Utility Generation Balancing Account (UGBA) balancing accounts will be implemented as revenue adjustment mechanisms effective January 1, 2004 to ensure that PG&E recovers its authorized electric distribution and electric generation revenue requirements regardless of the level of sales." (PG&E et al. 2003, Attachment A, 17) PG&E has proposed that rates be trued-up annually through an Electric Annual True-up Proceeding. In order to implement its bankruptcy settlement, PG&E filed an advice letter that includes the decoupling mechanisms agreed upon in the GRC (PG&E 2003). The Commission approved PG&E's decoupling mechanisms effective January 1, 2004, noting that "the revenue adjustment mechanisms comply with PU Code Section 739.10 by ensuring that errors in estimates of sales do not result in material over or undercollections." (CPUC 2004).

Southern California Edison (SCE). SCE has had a distribution-only revenue decoupling mechanism in place since April 2002 (CPUC 2002). This decoupling mechanism is part of SCE's performance-based ratemaking mechanism, which provides for an attrition mechanism that escalates the revenue requirement by inflation minus a productivity offset every year, and adds a factor to account for customer growth (CPUC 2002; SCE 2003). In SCE's current general rate case, the company proposed to extend and expand its decoupling mechanism to encompass

[8] Public Utilities Code Section 739.10, enacted by Assembly Bill 29x, provides that the Commission must "ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporation."
[9] California Public Utilities Commission proceedings A.02-11-017, A.02-05-004, A.02-12-028, and A.02-12-027.

generation as well as distribution revenue requirements. Both the proposed decision and the alternate decision in SCE's GRC would adopt this expanded decoupling mechanism, and would ensure that the utility is indifferent to the level of retail sales (Wetzel 2004, 265). A final decision by the Commission is expected on May 27, 2004.

San Diego Gas & Electric (SDG&E). In December 2002, SDG&E filed an application to implement a decoupling mechanism in its general rate case before the Commission. SDG&E proposed a revenue per customer mechanism, in order to provide "assurance that there is no disincentive for SDG&E to aggressively promote energy efficiency and environmental responsibility in the use of electricity and gas." (Reed 2002, 9) In May 2003, the Commission bifurcated the GRC, postponing consideration of SDG&E's proposed decoupling mechanism to Phase II of the GRC, which is now getting underway.

In its application, SDG&E proposes a margin per customer mechanism as part of a new distribution performance based ratemaking framework with a term of five years. This mechanism would establish an authorized revenue per customer that is adjusted annually for inflation and productivity; the annual authorized revenue requirement would be established by multiplying the revenue per customer by the forecasted number of customers annually through 2008 (Van Lierop 2004, 1, 4, 30, 31).[10] SDG&E proposes to establish an Electric Distribution Fixed Cost Account, which would operate as a balancing account to true-up the Company's authorized and actual revenues each year. The true-ups would be done through advice letter filings (Van Lierop 2004, 40-41). The Company notes that its proposed framework includes balancing account mechanisms identical to the Electric Revenue Adjustment Mechanism. A final decision on SDG&E's decoupling mechanism and performance based ratemaking framework is expected before the end of this year.

Southern California Gas Company (SoCal Gas). SoCal Gas has operated under a revenue per customer indexing mechanism since 1998. This methodology compensates SoCal Gas for the costs resulting from the growth in number of customers based on an established margin per customer, regardless of change in total throughput. This mechanism actually incents the utility to increase the efficiency of their service delivery per customer. SoCal Gas filed an application in December 2002 to extend this mechanism for five years, using the same reasoning presented in the SDG&E testimony noted above (Van Lierop 2003).

Oregon

In June 2001, Northwest Natural Gas Company filed an application to request Commission approval of a decoupling mechanism. The Public Utility Commission of Oregon subsequently adopted a settlement agreement signed by a number of parties to the Commission's proceeding, establishing a decoupling mechanism for the natural gas utility (Public Utility Commission of Oregon 2002). The mechanism includes monthly true-ups based on a comparison of weather-normalized usage to baseline volumes. In 2005, an independent assessment of the effectiveness of the decoupling mechanism will be conducted to inform the Commission's decision on whether to extend the mechanism (Public Utility Commission of Oregon 2002, 6).

[10] Note that this mechanism would exclude generation costs.

Washington

PacifiCorp's recent general rate case filing in Washington includes testimony by CEO Judi Johansen endorsing a decoupling mechanism:

> The Company's objectives in filing this rate case [include] eliminat[ing] financial disincentives to promoting energy efficiency improvements throughout the company's service territory . . . From a least-cost planning perspective, the problem with current ratemaking practice is the linkage of utilities' financial health to retail electricity throughput. Increased retail electricity sales produce higher fixed cost recovery and reduced sales have the opposite effect. To remove a conservation disincentive, we would propose that the parties agree to and the Commission endorse the adoption of a simple system of periodic true-ups to electric rates, designed to correct for the disparities between utilities' actual fixed cost recoveries and the revenue requirement approved by this Commission. The true-ups would either restore to the utilities or give back to customers the dollars that were under- or over-recovered as a result of annual throughput fluctuations. (Johansen 2003, 3,6)

The Utilities and Transportation Commission proceeding is just getting underway, and a decision is expected from the Commission by the end of the year.

Idaho

The Idaho Public Utilities Commission is currently considering a proposal to decouple Idaho Power Company's revenues from its sales in the utility's general rate case. The Northwest Energy Coalition and the Natural Resources Defense Council intervened in the GRC, and presented detailed testimony describing the disincentive currently faced by the utility in regards to investments in demand-side resources, and proposing a solution to the problem (Cavanagh 2004). A decision is expected from the Commission by mid-2004.

New York

When New York restructured its electricity industry, it left the utilities responsible for providing distribution service to customers and transferred central responsibility for administration of the energy efficiency programs (funded through a system benefit charge) to the New York Research and Development Authority (NYSERDA). While the utilities are no longer in the generation business, the current regulatory framework continues to tie their financial health to throughput over their wires. Niagara Mohawk Power Corporation filed comments at the New York Public Service Commission explaining that "[b]ecause a large proportion of the costs associated with the electricity delivery business do not vary with reductions in deliveries, most distribution companies have an economic disincentive to promote policies that reduce deliveries and their associated revenue." (Niagara 2003, 2)

This regulatory framework has created an incentive for the utilities to discourage investments in energy efficiency and other distributed resources, which has manifested itself in utility opposition to energy efficiency programs, the extension of New York's system benefit charge, and energy efficiency standards (Kennedy et al. 2003, 9-14).

On May 2, 2003, the New York Public Service Commission (PSC) opened a proceeding intended to "identify the degree to which New York electric delivery utility rate structures produce financial disincentives against the promotion of energy efficiency, renewable technologies and distributed generation and to develop recommendations for any necessary rate design changes to eliminate the disincentives." (NYPSC 2003, 4) Proponents of a true-up mechanism to decouple the utilities' revenues from sales form a diverse coalition of over 80 stakeholders, including Carrier Corporation, Johnson Controls, the Real Estate Board of New York, the Power Authority, and the New York Attorney General. A recommended decision in the PSC's proceeding is slated for summer of 2004.

Necessary, But Not Sufficient

The solution discussed above removes a perverse penalty on portfolio managers that reduces revenues and cost-recovery for promoting investments in energy efficiency and other distributed resources on the customer's side of the meter. This true-up mechanism is not an incentive; it only removes a disincentive. Under most current ratemaking structures, the earning opportunities for investor-owned utility portfolio managers are restricted to a rate of return on power plants and related capital investments that can be added to their rate base (in addition to selling more kWhs as addressed above). The ability to realize this return is not generally tied to performance, and this opportunity does not generally exist for other alternatives that minimize long-term costs. This not only disadvantages energy efficiency, it disadvantages long-term contracts with non-utility generators, clean distributed generation, and other more cost-effective alternatives for which assuming responsibility looks to management like a straight pass-through at best. Publicly-owned utilities and CCAs may not have an analogous "positive" incentive to invest in any particular type of resource, once their revenues are decoupled from sales.

Development of the most reliable, affordable, environmentally responsible energy service portfolio requires, among other things, a balanced, performance-based incentive system that provides the portfolio manager with risks and rewards to the extent it achieves (or does not achieve) these objectives. More than a decade ago, the National Association of Regulatory Commissioners urged its members to "ensure that the successful implementation of a utility's least-cost [investment and procurement] plan is its most profitable course of action." (Moskovitz 1989) The resolution framed the term "least-cost" over an extended time horizon. Congress endorsed NARUC's objective in the National Energy Policy Act of 1992, for both electric and gas utilities, although the final decision remains with state regulators.[11] In most states, currently regulatory incentives do not achieve NARUC's stated objective.

Some states do have performance-based incentives for investments in energy efficiency that help balance the incentives provided for some supply-side investments. For example, Massachusetts and Connecticut currently provide performance incentives for energy efficiency. California had several years of success with performance-based incentives for energy efficiency, but these too were abandoned as the state rushed to restructure its electric industry (Schlegel 1993).

Legislation recently enacted in California calls for the regulated utilities to file, for Commission review, procurement plans that include "[a]n incentive mechanism that establishes a procurement benchmark or benchmarks and authorizes the [utility] to procure from the market, subject to comparing the electrical corporation's performance to the commission-authorized benchmark or benchmarks. The incentive mechanism shall be clear, achievable, and contain quantifiable objectives and standards. The incentive shall contain balanced risk and reward

[11] See 16 USC section 2621 (d)(8).

incentives that limit the risk and reward of an electrical corporation."[12] The design of the performance-based mechanisms is being addressed in the Commission's current procurement proceeding. And the Commission plans to establish energy efficiency incentives as part of this comprehensive procurement incentive mechanism by the end of the year.

These performance-based incentives should be focused on the exemplary implementation of a comprehensive demand and supply resource procurement portfolio, and should ensure that investments in cost-effective energy efficiency and other demand reduction resources are at least as profitable as investments in generation, transmission and distribution services and equipment. With this type of balanced, performance-based incentive mechanism, there is no need for ratebasing of any new capital investments. All new resources should be competing on a level playing field.

Conclusion

There is nothing *inherent* about the conflict-of-interest faced by many portfolio managers relative to energy efficiency. All types of portfolio managers, whether public or private, can face conflicts-of-interest when cost recovery and profits are tied to sales volume, but this problem can be solved. Regulators and utilities in states around the country including California, New York, Oregon, Washington, and Idaho are implementing policies that remove any disincentive for investments in cost-effective energy efficiency and distributed resources.

Removing the link between financial health and sales is necessary, but not sufficient, to place energy efficiency investments on a more level playing field with competing resources. Development of the most reliable, affordable, environmentally responsible energy service portfolio requires, among other things, a balanced, performance-based incentive system that provides the portfolio manager with risks and rewards to the extent it achieves (or does not achieve) these objectives.

References

Bachrach, D., M. Ardema and A. Leupp. 2003. *Energy Efficiency Leadership in California: Preventing the Next Crisis.* Natural Resources Defense Council and Silicon Valley Manufacturing Group.

California Public Utilities Commission (CPUC). 2002. *Decision Granting Petition to Modify Southern California Edison Company's Performance Based Ratemaking Mechanism.* Decision 02-04-055. San Francisco, Calif.: California Public Utilities Commission. April 22.

California Public Utilities Commission (CPUC). 2003. *Interim Opinion Implementing Provisions of Assembly Bill 117 Relating to Energy Efficiency Program Fund Disbursements.* Decision 03-07-034. San Francisco, Calif.: California Public Utilities Commission. July 14.

California Public Utilities Commission (CPUC). 2004. *Resolution E-3862*. April 1.

[12] See California Public Utilities Code section 454.5 (c) (2).

Cape Light Compact. 2003. *Energy Plan 2015.* Barnstable, Mass.: Cape Light Compact.

Cape Light Compact. 2004. Available online: www.capelightcompact.org. Barnstable, Mass.: Cape Light Compact.

Carter, S. 2001. "Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions." *Electricity Journal* (December): 66-74.

Cavanagh, R. 2004. *Direct Testimony of Ralph Cavanagh.* Idaho Public Utilities Commission Case No. IPC-E-03-13. February 18.

Davis, R. (Burbank Water and Power). 2004. "Utility Support of the General Fund." Memorandum to City Manager, Burbank, Calif., May 13.

Downey, Maggie (Cape Light Compact). 2004. Personal Communication. May 13.

Eto, J., S. Stoft, and T. Belden. 1994. *The Theory and Practice of Decoupling.* LBL-34555. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Harrington, C., D. Moskovitz, W. Shirley, F. Weston, R. Sedano, and R. Cowart. 2002. *Portfolio Management: Protecting Customers in an Electric Market That Isn't Working Very Well.* Montpelier, Vt.: Regulatory Assistance Project for the Energy Foundation and the Hewlett Foundation.

Johansen, J.A. 2003. *Direct Testimony of Judith A. Johansen.* Washington Utilities and Transportation Commission v. PacifiCorp. Docket No. UE-032065. Ore.: PacifiCorp.

Kennedy, K., A. Gupta, N. Greene, F. Zalcman, D. Rosenblum. 2003. *Comments of the Natural Resources Defense Council and Pace Energy Project*. NYPSC Case 03-E-0640. October 23.

Maine Public Advocate Office. 2002. *Electricity Guide.* Available online: www.state.me.us/meopa/elec%20vol%206%2003-02.pdf. Augusta, Maine: Maine Public Advocate Office.

Marnay, C. and G.A. Comnes. 1990. *Ratemaking for Conservation: The California ERAM Experience.* LBL-28019. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Moskovitz, D. 1989. *Profits and Progress Through Least-Cost Planning.* Washington, D.C.: The National Association of Regulatory Utility Commissioners.

New York Public Service Commission (NYPSC). 2003. *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*. NYPSC Case 03-E-0640. May 2.

Niagara Mohawk Power Corporation (Niagara). 2003. *Comments by Niagara Mohawk Power Corporation*. NYPSC Case 03-E-0640. October 23.

Northeast Ohio Public Energy Council (NOPEC). 2004. Available online: www.nopecinfo.org. Ohio: Northeast Ohio Public Energy Council.

Owens, D. and R. Cavanagh (Edison Electric Institute and Natural Resources Defense Council). 2003. Letter to National Association of Regulatory Utility Commissioners. November 18.

Pacific Gas and Electric Company (PG&E). 2003. *Implementation of the Ratemaking Provisions Supporting the Settlement Agreement Adopted in Decision 03-12-035.* Advice 2510-G / 2460-E. December 31.

Pacific Gas and Electric Company et al. (PG&E). 2003. *Motion of Pacific Gas and Electric Company, Office of Ratepayer Advocates, The Utility Reform Network, Aglet Consumer Alliance, Modesto Irrigation District, Natural Resources Defense Council and the Agricultural Energy Consumers Association for Approval of Settlement Agreement.* A.02-11-017 et al. San Francisco, Calif.: Pacific Gas and Electric Company. September 15.

Public Utility Commission of Oregon. 2002. Order No. 02-634. Salem, Ore.: Public Utility Commission of Oregon. September 12.

Reed, D.L. 2002. *Prepared Direct Testimony of Debra L. Reed on Behalf of San Diego Gas & Electric Company.* CPUC A.02-12-028. San Diego Gas & Electric Company. December 20.

Schlegel, J. et al. (Wisconsin Energy Conservation Corporation). 1993. *Evaluation of DSM Shareholder Incentive Mechanisms.* Madison, Wisc.: Wisconsin Energy Conservation Corporation for the California Public Utilities Commission.

Silverstein, K. 2004. "Cities Eye Munis for New Revenues." *UtilitPoint International IssueAlert.* March 24.

Southern California Edison (SCE). 2003. *Electric Distribution Revenue Adjustment Balancing Account*, Preliminary Statement XX. Available online: www.sce.com/sc3/005_regul_info/005 tariffbook/005a2prelim.htm. November 3.

Van Lierop, J. 2003. *Revised Direct Testimony of Johannes Van Lierop on Behalf of Southern California Gas Company*. CPUC A.02-12-027. Southern California Gas Company.

Van Lierop, J. 2004. *Revised Direct Testimony of Johannes Van Lierop on Behalf of San Diego Gas & Electric Company.* CPUC A.02-12-028. San Diego Gas & Electric Company.

Wetzel. 2004. *Proposed Decision: Opinion on Base Rate Revenue Requirement and Other Phase I Issues*, CPUC A.02-05-004 et al. San Francisco, Calif.: California Public Utilities Commission. February 13.