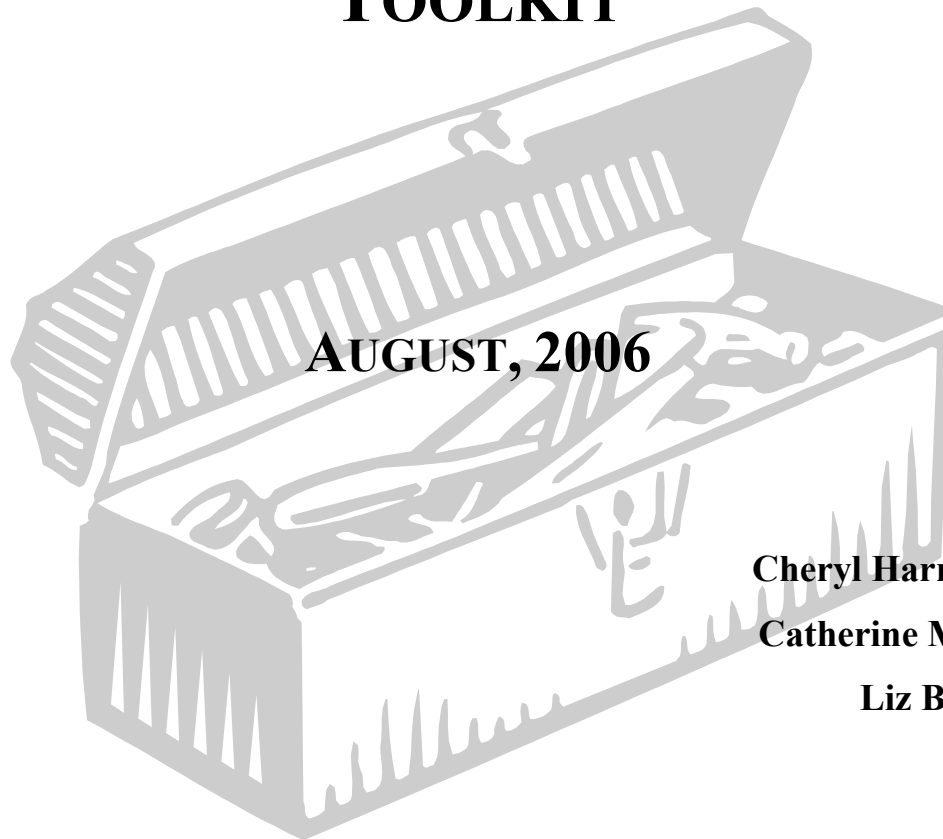


ENERGY EFFICIENCY POLICY TOOLKIT



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**Cheryl Harrington
Catherine Murray
Liz Baldwin**



The Regulatory Assistance Project

50 STATE STREET, SUITE 3
MONTPELIER, VT 05602
TEL: 802-223-8199
FAX: 802-223-8172

WEBSITE:
[HTTP://WWW.RAPONLINE.ORG](http://www.raponline.org)

177 WATER STREET
GARDINER, ME 04345
TEL: 207-582-1135
FAX: 207-582-1176

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Clean Energy Policies

For Electric and Gas Utility Regulators

In light of the higher natural gas prices and electricity prices occurring in their states, many electric and gas utility regulators have a growing interest in energy efficiency and renewable energy and in encouraging the use of distributed generation. These clean energy resources have high value in meeting the need for affordable, reliable generation, transmission and distribution for both electricity and natural gas, but they require careful policy groundwork to assure their development.

Rather than address *why* policy makers might want to develop more aggressive clean energy policies, this Energy Efficiency Policy Toolkit assumes you are already interested. It sets out a compendium of tried and true regulatory policies that will advance the development of cost-effective clean energy within both the electric and gas systems in your state. We examine policy options in four primary areas: energy efficiency, renewable energy, distributed resources and rate design. We also discuss the key importance of regulatory financial incentives which play an essential role in either discouraging or supporting the development of clean energy, particularly energy efficiency.

A decade of restructuring activity has created great variation among states in their models for electric sector regulation. But all states continue to set retail electric and gas rates for the vast majority of customers under standard offer arrangements. Regulatory policy continues to heavily influence clean resource decisions, by default if not by design.

ENERGY EFFICIENCY AS A RESOURCE

Available, cost-effective energy efficiency could greatly reduce the current demand for electricity and natural gas in the US. Even a modestly aggressive program could meet a high percentage of the load growth we now face. Using untapped efficiency is the single most effective step energy and energy market regulators can take to reduce environmental pollution, power costs, and price volatility.

Energy Efficiency Is A Resource

The required policy decision is that energy efficiency is a resource to be acquired on a basis equivalent to that of supply side resources at all levels within the electric system: generation, transmission, and distribution, as well as the natural gas supply system. When costs are the same, efficiency should be acquired first.

Declaration of Efficiency as a Resource

California: Energy Action Plan

The Energy Action Plan (EAP) was jointly adopted in 2003 by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the Consumer Power and Conservation Financing Authority (CPA). It has been endorsed by Governor Schwarzenegger, and continues to serve as the blueprint for subsequent resource acquisition decisions.

The Action Plan envisions a “loading order” of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to “get to scale,” the agencies also will support additional clean, fossil fuel, central-station generation.¹

. . . California should decrease its per capita electricity use through increased energy conservation and efficiency measures. This would minimize the need for new generation, reduce emissions of toxic and criteria pollutants and greenhouse gases, avoid environmental concerns, improve energy reliability and contribute to price stability. Optimizing conservation and resource efficiency will include the following specific actions:

1. Implement a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts by 2007.
2. Improve new and remodeled building efficiency by 5 percent.
3. Improve air conditioner efficiency by 10 percent above federally mandated standards.
4. Make every new state building a model of energy efficiency.
5. Create customer incentives for aggressive energy demand reduction.
6. Provide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects.
7. Increase local government conservation and energy efficiency programs.

¹ State of California Energy Action Plan I, p.4. See http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.DOC

8. Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction.
9. Encourage companies that invest in energy conservation and resource efficiency to register with the state's Climate Change Registry.²

Montana: Administrative Rules

Montana's Administrative Rules regarding Integrated Resource Planning state:

The goal of these integrated least cost resource planning guidelines is to encourage electric utilities to meet their customers' needs for adequate, reliable and efficient energy services at the lowest total cost while remaining financially sound. To achieve this goal utilities should plan to meet future loads through timely acquisition of an integrated set of demand- and supply-side resources. Importantly, this includes actively pursuing and acquiring all cost effective energy conservation. The cost effectiveness of all resources should be determined with respect to long-term societal costs.³

Note: Montana's two main utilities are regulated differently. The IRP rules quoted above apply to Montana's traditionally regulated utility; another utility is restructured and participates in a different planning process. See also Montana entries in "Least-Cost or Integrated Resource Planning" and "Portfolio Management and Default Supply Procurement" sections.

New Mexico: Statute

The legislature finds that:

A [E]nergy efficiency and load management are cost-effective resources that are an essential component of the balanced resource portfolio that public utilities must achieve to provide affordable and reliable energy to public utility consumers...⁴
"It is the policy of the Efficient Use of Energy Act that public utilities, distribution cooperative utilities and municipal utilities include cost-effective energy efficiency and load management investments in their energy resource portfolios and that any regulatory disincentives that may exist to public utility investments in cost-effective energy efficiency and load management are eliminated."⁵

Pacific Northwest: The Northwest Power Act

The federal Northwest Power Act of 1980 required the establishment of the Pacific Northwest Electric Power and Conservation Planning Council, which is tasked with promoting conservation and protecting fish and wildlife in the Pacific Northwest. The Council is required to prepare an electric resource plan as follows:

² Ibid, p.5

³ Administrative Rules of Montana 38.5.2001. See <http://arm.sos.state.mt.us/38/38-697.htm>

⁴ New Mexico Statutes, Chapter 62-17-2. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

⁵ New Mexico Statutes, Chapter 62-17-3. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

839b(e)(1). The plan shall, as provided in this paragraph, give priority to resources which the Council determines to be cost-effective. Priority shall be given: first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources.⁶

839d(a)(1). The Administrator shall acquire such resources through conservation, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load, as the Administrator determines are consistent with the plan, or if no plan is in effect with the criteria of section 839b(e)(1) of this title and the considerations of section 839b(e)(2) of this title and, in the case of major resources, in accordance with subsection (c) of this section.⁷

Energy Efficiency Portfolio Standard/Targets

A number of states have specific energy efficiency goals for utilities. These may be expressed as a percentage of load or load growth, or they may be utility-specific numeric targets. Other states have incorporated efficiency into a Renewable Portfolio Standard goal, allowing efficiency to meet renewable energy goals.

California

CPUC Decision 0409060, issued in September 2004, states that:

The Energy Action Plan . . . identifies reduction of energy use per capita as one of six sets of actions that are of critical importance. By today's decision, we have translated this mandate into explicit, numerical goals for electricity and natural gas savings for the four largest investor-owned utilities.⁸

The order established the expectation that the four utilities would achieve 70% of the economic potential and 90% of the maximum achievable potential energy efficiency available, quantified into explicit annual GWh/therm savings targets for each utility that increase yearly through 2012⁹. Some excerpts from the Order:

In submitting proposed energy efficiency program plans and funding levels to meet the savings goals adopted by the Commission, the program administrator(s) shall:

⁶ Northwest Power Act, 839b(e)(1). See http://www.nwcouncil.org/library/poweract/4d_4g_powerplan.htm

⁷ Northwest Power Act, 839d(a)(1). See http://www.nwcouncil.org/library/poweract/6_conservation.htm

⁸ CPUC D. 04-09-060. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm#P95_2834

⁹ Tables of savings goals available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212-07.htm#P285_94932 (bottom of page)

- a. Demonstrate that their proposed level of electric and natural gas energy efficiency program activities and funding is consistent with the Commission's -adopted electric and natural gas savings goals.,
- b. If there are differences between the near-term numerical goals and the savings levels associated with the program portfolios proposed for PY2006-PY2008, specifically describe how the numerical goals in later years will still be met by ramping up program efforts over time, by initiating innovative programs to improve program-effectiveness ratios, or by other means.
- c. Submit an analysis of a wide range of promising options to remove barriers to the rapid deployment of energy efficiency with the PY2006-PY2008 program plans, including on-bill financing of energy efficiency measures. In doing so, program administrator(s) should look to the practices used in other states to resolve the ratemaking, cost allocation and consumer protection issues raised by the parties in this proceeding regarding on-bill financing.
- d. Present specific proposals for programs that support new building and appliance standards.
- e. Present estimates of the net rate impacts and bill impacts associated with the proposed portfolio of programs designed to meet the Commission-adopted energy savings goals. The program administrator(s) shall work with Joint Staff to develop a consistent format for presenting these estimates in their filings.

The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term. To this end, our upcoming decisions in R. 04-04-003 concerning the long-term procurement plans and 2005/2006 ongoing procurement authorizations of PG&E, SCE and SDG&E shall be made in full recognition of the aggressive energy savings goals we adopt today. For the procurement plans that will be filed in 2006 and during subsequent procurement plan cycles, or for any updating to the long-term procurement plans required by the Commission before then, PG&E, SDG&E and SCE shall incorporate the most recently-adopted energy savings goals into those filings.

In any application or other filing in which PG&E, SCE, SDG&E or SoCalGas present projections of supply-side resource needs, pipeline or transmission needs, propose new facilities or otherwise utilize projections of energy demand, they shall demonstrate that such filings are fully consistent with and reflect today's adopted energy savings goals, or updates to these goals as adopted by the Commission.

PG&E, SDG&E and SoCalGas shall reflect the natural gas energy savings goals adopted in today's decision, or as updated from time to time by the Commission, in their BCAP filings and other proceedings where natural gas demand projections are submitted for Commission consideration.¹⁰

¹⁰ CPUC Decision 0409060. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212-07.htm#P285_94932

Connecticut

Connecticut's 2005 Energy Independence Act requires utilities to procure a certain percentage of supply from "Class III" resources, including certain types of DSM:

"Class III renewable energy source" means the electricity output from combined heat and power systems with an operating efficiency level of no less than fifty per cent that are part of customer-side distributed resources developed at commercial and industrial facilities in this state on or after January 1, 2006, or the electricity savings created at commercial and industrial facilities in this state from conservation and load management programs begun on or after January 1, 2006.¹¹

...
Sec. 16. (NEW) (*Effective from passage*) (a) On and after January 1, 2007, each electric distribution company providing standard service pursuant to section 16-244c of the general statutes, as amended by this act, and each electric supplier as defined in section 16-1 of the general statutes, as amended by this act, shall demonstrate to the satisfaction of the Department of Public Utility Control that not less than one per cent of the total output of such supplier or such standard service of an electric distribution company shall be obtained from Class III resources. On and after January 1, 2008, not less than two per cent of the total output of any such supplier or such standard service of an electric distribution company shall, on demonstration satisfactory to the Department of Public Utility Control, be obtained from Class III resources. On or after January 1, 2009, not less than three per cent of the total output of any such supplier or such standard service of an electric distribution company shall, on demonstration satisfactory to the Department of Public Utility Control, be obtained from Class III resources. On and after January 1, 2010, not less than four per cent of the total output of any such supplier or such standard service of an electric distribution company shall, on demonstration satisfactory to the Department of Public Utility Control, be obtained from Class III resources. Electric power obtained from customer-side distributed resources that does not meet air quality standards of the Department of Environmental Protection is not eligible for purposes of meeting the percentage standards in this section.

(b) Except as provided in subsection (d) of this section, the Department of Public Utility Control shall assess each electric supplier and each electric distribution company that fails to meet the percentage standards of subsection (a) of this section a charge of up to five and five-tenths cents for each kilowatt hour of electricity that such supplier or company is deficient in meeting such percentage standards. Seventy-five per cent of such assessed charges shall be deposited in the Energy Conservation and Load Management Fund established in section 16-245m of the general statutes, as amended by this act, and twenty-five per cent shall be deposited in the Renewable Energy Investment Fund established in section 16-245n of the general statutes, as amended by this act, except that such seventy-five per cent of assessed charges with respect to an electric supplier shall be divided among the Energy Conservation and Load Management Funds of electric distribution companies in proportion to the amount of electricity such electric supplier

¹¹ Connecticut Energy Independence Act, Section 1. See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>.

provides to end use customers in the state using the facilities of each electric distribution company.

(c) An electric supplier or electric distribution company may satisfy the requirements of this section by participating in a conservation and distributed resources trading program approved by the Department of Public Utility Control. Credits created by conservation and customer-side distributed resources shall be allocated to the person that conserved the electricity or installed the project for customer-side distributed resources to which the credit is attributable and to the Energy Conservation and Load Management Fund. Such credits shall be made in the following manner: A minimum of twenty-five per cent of the credits shall be allocated to the person that conserved the electricity or installed the project for customer-side distributed resources to which the energy credit is attributable and the remainder of the credits shall be allocated to the Energy Conservation and Load Management Fund, based on a schedule created by the department no later than January 1, 2007, and reviewed annually thereafter. The department may, in a proceeding and for good cause shown, allocate a larger proportion of such credits to the person who conserved the electricity or installed the customer-side distributed resources. The department shall consider the proportion of investment made by a ratepayer through various ratepayer-funded incentive programs and the resulting reduction in federally mandated congestion charges. The portion allocated to the Energy Conservation and Load Management Fund shall be used for measures that respond to energy demand and for peak reduction programs.

(d) An electric distribution company providing standard service may contract with its wholesale suppliers to comply with the conservation and customer-side distributed resources standards set forth in subsection (a) of this section. The Department of Public Utility Control shall annually conduct a contested case, in accordance with the provisions of chapter 54 of the general statutes, to determine whether the electric distribution company's wholesale suppliers met the conservation and distributed resources standards during the preceding year. Any such contract shall include a provision that requires such supplier to pay the electric distribution company in an amount of up to five and one-half cents per kilowatt hour if the wholesale supplier fails to comply with the conservation and distributed resources standards during the subject annual period. The electric distribution company shall immediately transfer seventy-five per cent of any payment received from the wholesale supplier for the failure to meet the conservation and distributed resources standards to the Energy Conservation and Load Management Fund and twenty-five per cent to the Renewable Energy Investment Fund. Any payment made pursuant to this section shall not be considered revenue or income to the electric distribution company.

(e) The Department of Public Utility Control shall conduct a contested proceeding to develop the administrative processes and program specifications that are necessary to implement a Class III conservation and distributed resources trading program. The proceeding shall include, but not be limited to, an examination of issues such as (1) the manner in which qualifying activities are certified, tracked and reported, (2) the manner in which Class III certificates are created, accounted for and transferred, (3) the

feasibility and benefits of expanding eligible Class III resources to include those resulting from electricity savings made by residential customers, (4) verification of the accuracy of conservation and customer-side distributed resources credits, (5) verification of the fact that resources or credits used to satisfy the requirement of this section have not been used to satisfy any other portfolio or similar requirement, (6) the manner in which credits created by conservation and customer-side distributed resources may best be allocated to maximize the impact of the trading program, and (7) setting such alternative payment amounts at a level that encourages development of conservation and customer-side distributed resources. The department may retain the services of a third party entity with expertise in the development of energy efficiency trading or verification programs to assist in the development and operation of the program. The department shall issue a decision no later than February 1, 2006.¹²

Illinois

The ICC in July 2005 adopted the governor's proposed Sustainable Energy Plan, including a provision that efficiency be acquired to reduce load growth:

IT IS THEREFORE RESOLVED by the Illinois Commerce Commission that the Commission hereby adopts the Governor's proposed Sustainable Energy Plan¹³ with modifications based on information gathered through the Sustainable Energy Initiative and Staff's Report.

IT IS FURTHER RESOLVED that the Energy Efficiency Portfolio Standard should be set as follows: years 2007-2008 at 10% reduction in load growth, years 2009-2011 at 15% reduction in load growth, years 2012-2014 at 20% reduction in load growth and years 2015-2017 at 25% reduction in load growth.¹⁴

New Jersey

The New Jersey Board of Public Utilities (BPU) has initiated two comprehensive Resource Analysis Proceedings that have guided procurement of efficiency resources. The first, in March 2001, established 2001-2004 funding levels for the Clean Energy Program. The second, in May 2004, initiated a series of meetings intended to address questions about the Clean Energy Program. An Order from Docket EX04040376, issued on 12/23/04, approved funding levels and savings goals for 2005 through 2008:

The Board concurs with Staff's recommendation that for the energy efficiency programs, goals should be established such that for every percentage increase in funding compared to 2003 funding levels, the goal should be to increase energy saving over 2003 levels by the percent increase in funding plus 10%. That is, if the energy efficiency funding level increases by 10% over the level expended on energy efficiency in 2003, the goal should be to increase energy savings by 20% over 2003 levels. The Board believes such goals

¹² Ibid., Section 16.

¹³ The full Plan is available at http://www.renewableenergyaccess.com/assets/download/IllinoisGov_RPS.pdf

¹⁴ Illinois Commerce Commission Resolution 05-0437. See http://eweb.icc.state.il.us/e-docket/reports/view_file.asp?intIdFile=148072&strC=bd.

are reasonable and will continue to exert pressure on the program managers to lower the cost of delivered energy savings.¹⁵

Pennsylvania

Act 213, passed in 2004, requires that a percentage of all electricity sold to PA customers come from “alternative energy sources”. Demand-side management is considered a Tier II resource (along with waste coal, distributed generation, large-scale hydro, and municipal solid waste). The Act states that:

Of the electrical energy required to be sold from alternative energy sources identified in Tier II, the percentage that must be from these technologies is for:

YEARS 1 THROUGH 4 - 4.2%.

YEARS 5 THROUGH 9 - 6.2%.

YEARS 10 THROUGH 14 - 8.2%.

YEARS 15 AND THEREAFTER - 10.0%.¹⁶

PUC Docket No. M-00051865 was opened to oversee implementation of the Act, including developing methodology for tracking and verifying DSM savings. The Final Order developed a Technical Reference Manual with formulas for tracking and verification:

The Commission will be guided by the following principles in establishing the rules for DSM/EE measures:

- Market values for individual measures or measures installed as group program items.
- Easily understood rules with minimal transaction and administrative costs.
- Reliance upon existing state and federal protocols.
- Equitable opportunities for residential, commercial and industrial customers to benefit directly.¹⁷

Texas

Texas’ 1999 restructuring statute, the Public Utilities Regulatory Act, requires distribution utilities to meet 10% of forecast load growth through efficiency.

a) It is the goal of the legislature that:

(1) electric utilities will administer energy savings incentive programs in a market-neutral, nondiscriminatory manner but will not offer underlying competitive services;

¹⁵ NJBPU Docket EX04040376, Order of 12/23/04, p. 30. See http://www.bpu.state.nj.us/wwwroot/cleanEnergy/EX04040276_20041223.pdf

¹⁶ Act 214 of the 2004 Pennsylvania Legislature. <http://www2.legis.state.pa.us/WU01/LI/BI/BT/2003/0/SB1030P1973.pdf>, p. 12

¹⁷ Pennsylvania Public Utilities Commission Docket No. M-00051865, Final Order, p. 4. See <http://www.puc.state.pa.us/PcDocs/569133.doc>.

(2) all customers, in all customer classes, have a choice of and access to energy efficiency alternatives and other choices from the market that allow each customer to reduce energy consumption and reduce energy costs; and

(3) each electric utility will provide, through market-based standard offer programs or limited, targeted, market-transformation programs, incentives sufficient for retail electric providers and competitive energy service providers to acquire additional cost-effective energy efficiency equivalent to at least 10 percent of the electric utility's annual growth in demand.

(b) The commission shall provide oversight and adopt rules and procedures, as necessary, to ensure that the goal of this section is achieved by January 1, 2004.¹⁸

In addition, a 2001 statute, SB5, requires 38 local governments to decrease electricity usage 5% annually for 5 years.¹⁹

Energy Efficiency Utilities

In order to address utilities' disincentive to pursuing energy efficiency (see following section, "Align Utility Profit Motives With Efficiency Investment Requirements"), some states have created a third party efficiency administrator, sometimes referred to as an "energy efficiency utility." These organizations provide efficiency programs on a statewide basis and their sole task is to reduce kWh usage.

Hawaii

The 2006 Legislature authorized the Hawaii Public Utilities Commission to create an energy efficiency utility.

§269-A Public benefits fund; authorization. (a) The public utilities commission, by order or rule, may redirect all or a portion of the funds collected through the current demand-side management surcharge by Hawaii's electric utilities into a public benefits fund that may be established by the public utilities commission.

(b) If the public utilities commission establishes a public benefits fund, the surcharge shall be known as the public benefits fee. Moneys in the fund shall be ratepayer funds that shall be used to support energy-efficiency and demand-side management programs and services, subject to the review and approval of the public utilities commission. These moneys shall not be available to meet any current or past general obligations of the State.

§269-B Public benefits fund administrator; establishment. (a) If the public utilities commission establishes a public benefits fund, the public utilities commission shall appoint a fund administrator to operate and manage any programs established under section 269-A. The fund administrator shall not expend more than ten per cent of the fund in any fiscal year, or other reasonable percentage determined by the public utilities commission, for administration of the programs established under section 269-A.

¹⁸ Texas Utilities Code 39.905. See <http://www.capitol.state.tx.us/statutes/ut.toc.htm>

¹⁹ Texas Health and Safety Code, Chapter 386. See <http://www.capitol.state.tx.us/statutes/hs.toc.htm>

(b) The fund administrator shall be subject to regulation by the public utilities commission, including pursuant to sections 269-7, 269-8, 269-8.2, 269-8.5, 269-9, 269-10, 269-13, 269-15, 269-19.5, and 269-28, and shall report to the public utilities commission on a regular basis. Notwithstanding any other provision of law to the contrary, the fund administrator shall not be an electric public utility or an electric public utility affiliate.

§269-C Requirements for the public benefits fund administrator. (a) Any fund administrator appointed pursuant to section 269-B shall satisfy the qualification requirements established by the public utilities commission by rule or order. These requirements may include experience and expertise in:

- (1) Energy-efficient and renewable energy technologies and methods; and
- (2) Identifying, developing, administering, and implementing demand-side management and energy-efficiency programs.

(b) The fund administrator's duties and responsibilities shall be established by the public utilities commission by rule or order, and may include:

- (1) Identifying, developing, administering, promoting, implementing, and evaluating programs, methods, and technologies that support energy-efficiency and demand-side management programs;
- (2) Encouraging the continuance or improvement of efficiencies made in the production, delivery, and use of energy-efficiency and demand-side management programs and services;
- (3) Using the energy-efficiency expertise and capabilities that have developed or may develop in the State and consulting with state agency experts;
- (4) Promoting program initiatives, incentives, and market strategies that address the needs of persons facing the most significant barriers to participation;
- (5) Promoting coordinated program delivery, including coordination with electric public utilities regarding the delivery of low-income home energy assistance, other demand-side management or energy-efficiency programs, and any utility programs;
- (6) Consideration of innovative approaches to delivering demand-side management and energy-efficiency services, including strategies to encourage third party financing and customer contributions to the cost of demand-side management and energy-efficiency services; and
- (7) Submitting, to the public utilities commission for review and approval, a multi-year budget and planning cycle that promotes program improvement, program stability, and maturation of programs and delivery resources.

§269-D Transitioning from utility demand-side management programs to the public benefits fund. If the public utilities commission establishes a public benefits fund pursuant to section 269-A, the public utilities commission shall:

- (1) Develop a transition plan that ensures that:
 - (A) Utility demand-side management programs are continued, to the extent practicable, until the transition date; and
 - (B) The fund administrator will be able to provide demand-side management and energy-efficiency services on the transition date;
- (2) Encourage programs that allow all retail electricity customers, including state and county agencies, regardless of the retail electricity or gas provider, to have an opportunity to participate in and benefit from a comprehensive set of cost-effective demand-side

- management and energy-efficiency programs and initiatives designed to overcome barriers to participation;
- (3) Encourage programs, measures, and delivery mechanisms that reasonably reflect current and projected utility integrated resource planning, market conditions, technological options, and environmental benefits;
 - (4) Facilitate the delivery of these programs as rapidly as possible, taking into consideration the need for these services and cost-effective delivery mechanisms;
 - (5) Consider the unique geographic location of the State and the high costs of energy in developing programs that will promote technologies to advance energy efficiency and use of renewable energy and permit the State to take advantage of activities undertaken in other states, including the opportunity for multi-state programs;
 - (6) Require the fund administrator appointed by the public utilities commission under section 269-B to deliver programs in an effective, efficient, timely, and competent manner and to meet standards that are consistent with state policy and public utilities commission policy; and
 - (7) Before January 2, 2008, and every three years thereafter, require verification by an independent auditor of the reported energy and capacity savings and incremental renewable energy production savings associated with the programs delivered by the fund administrator appointed by the public utilities commission to deliver energy-efficiency and demand-side management programs under section 269-A.²⁰

Oregon

Oregon's 1999 restructuring legislation established a public purpose charge and authorized the Oregon Public Utilities Commission to contract with a third party for administration of the funds.

(1) There is established an annual public purpose expenditure standard for electric companies to fund new cost-effective local energy conservation, new market transformation efforts, the above-market costs of new renewable energy resources, and new low-income weatherization. The public purpose expenditure standard shall be funded by the public purpose charge described in subsection (2) of this section. . .

(3)(d)The commission may also direct that funds collected by an electric company through public purpose charges be paid to a nongovernmental entity for investment in public purposes described in subsection (1) of this section. Notwithstanding any other provision of this subsection, at least 80 percent of the funds allocated for conservation shall be spent within the service area of the electric company that collected the funds.²¹

In October 2000, the PUC approved the concept of a non-profit PPC administrator, and the Energy Trust of Oregon, Inc., was established in 2001. The Energy Trust began running pilot programs in 2002.

²⁰ Hawaii 2006 Legislature, Senate Bill 3185. Amends Chapter 269 of the Hawaii Code. See http://www.capitol.hawaii.gov/sessioncurrent/bills/SB3185_CD1_.htm

²¹ 1999 Oregon Legislative Session SB 1149. See <http://www.energytrust.org/library/policies/sb1149.pdf>

Vermont

A 1999 Memorandum of Understanding (MOU) between The Department of Public Service and Vermont utilities was approved by the PSB. In the MOU, signatory parties agreed that the PSB should establish an Energy Efficiency Utility (EEU) to deliver statewide efficiency programs. EEU funding would come from the EEC, which would be determined by the PSB for each utility on an individual basis, with total funding starting at \$8.25 million in 2000, increasing to \$16.5 million in 2004²².

The total each DU must collect from its customers for the EEU program is set forth in each bilateral agreement. . . . The MOU provides that this EEU program budget will be funded through a separately stated, non-bypassable, volumetric system benefits charge on the bill from the electric utility to customers, as authorized under newly enacted 30 V.S.A. § 209(d)(3). The MOU provides that rate design for the benefits charge will be set by the Board. In its 2002 evaluation report, the DPS may make recommendations about whether to eventually create a uniform state-wide charge.²³

Budget levels for the EEU have subsequently been revised upwards. See “System Benefit Charges” section for more information.

Align Utility Profit Motives With Efficiency Investment Requirements

In conventional “cost plus” utility regulation, utility revenues and profits are linked to unit (kW, kWh, mcf or therms) sales. Under this system, loss of sales due to successful implementation of energy efficiency will lower utility profitability, and the effect may be quite powerful. For example, a 5% decrease in sales can lead to a 25% decrease in net profit for an integrated utility. For a stand-alone distribution utility, the loss to net profit is even greater – about double the impact. This basic sales incentive is at odds with a requirement to invest in cost-effective energy efficiency. Policies can, instead, align utilities’ profit motives with acquisition of all cost-effective energy efficiency.

The most effective method for eliminating this sales incentive/efficiency disincentive is to *decouple* utility revenues from its sales. A utility’s revenue requirement is determined through ordinary rate cases. Differences between the allowed revenues and actual revenues received in each ensuing year can be tracked on a per-customer or other basis. The difference (positive or negative) is flowed back to customers in a small adjustment to unit rates in the following year.

Another method of addressing lost sales revenues due to utility ratepayer funded efficiency investments is through an adjustment that tracks the implementation of energy efficiency and uses statistical means to determine lost revenues. Recovery of lost revenue (actually, *net* lost revenue, which accounts for utility cost savings attributable to the

²² Docket 5980, September 30, 1999 Order, p. 43. See <http://www.state.vt.us/psb/orders/document/5980phase2fnl.pdf>

²³ *Ibid.*, p. 46

efficiency investment) can be contingent on achieving certain energy efficiency program goals.

States also can provide increased or diminished points on allowed rate of return for meeting predetermined (high and higher) levels of successful efficiency implementation.

Removing Disincentives

Connecticut

Sec. 16-19kk. Finding re conservation and load management programs. Department's investigation into a company's earnings and volume of sales. Rates of return for conservation and load management programs and programs promoting the state's economic development. Considerations in establishing company's authorized return. Performance-based incentives. Consumer Counsel authorized to retain experts. Regulations. (a) The General Assembly finds that if the earnings of electric, gas, telephone and water public service companies, as defined in section 16-1, are adversely affected by such companies' conservation and load management programs or other programs promoting the state's economic development, energy and other policy, those companies will have a disincentive to implement such programs. The General Assembly further finds that in order to further the implementation of such programs the earnings of electric, gas, telephone and water companies should be consistent with the principles and guidelines set forth in sections 16-19e, 16-19aa and 16-19kk to 16-19oo, inclusive, and 16a-49 notwithstanding participation in conservation and load management programs and other programs authorized by the Department of Public Utility Control, promoting the state's economic development, energy and other policy.

(b) The department shall complete, on or before December 31, 1991, an investigation into the relationship between a company's volume of sales and its earnings. The department shall, on or before July 1, 1993, implement rate-making and other procedures and practices in order to encourage the implementation of conservation and load management programs and other programs authorized by the department promoting the state's economic development, energy and other policy. Such procedures to implement a modification or elimination of any direct relationship between the volume of sales and the earnings of electric, gas, telephone and water companies may include the adoption of a sales adjustment clause pursuant to subsection (i) of section 16-19b, or other adjustment clause similar thereto. The department's investigation shall include a review of its regulations and policies to identify any existing disincentives to the development and implementation of cost effective conservation and load management programs and other programs promoting the state's economic development, energy and other policy.

(c) Notwithstanding the provisions of subdivision (4) of subsection (a) of section 16-19e, in a proceeding under subsection (a) of section 16-19 the department shall consider for an electric, gas, telephone or water public service company, as defined in section 16-1, in establishing the company's authorized return within the range of reasonable rates of return: Quality, reliability and cost of service provided by the company, the reduced or

shifted demand for electricity, gas or water resulting from the company's conservation and load management programs approved by the department, the company's successful implementation of programs supporting economic development of the state and the company's success in decreasing or constraining dependence on the use of petroleum or any other criteria consistent with the state energy or other policy. The department may also establish other performance-based incentives both related and unrelated to the company's rate of return designed to implement the purposes of said sections 16-19e, 16-19aa, 16-19kk to 16-19oo, inclusive, and 16a-49.

(d) In any proceeding before the department in which a company seeks beneficial rate treatment pursuant to this section, the Office of Consumer Counsel may retain independent experts to provide analysis, evaluation and testimony to address the issue of the appropriateness of such beneficial treatment under consideration in the proceeding, and all reasonable and proper expenses, to provide such analysis, evaluation and testimony, to a maximum of fifty thousand dollars per proceeding, shall be paid by the company and shall be proper rate-making expenses.

(e) The Department of Public Utility Control may adopt regulations, in accordance with the provisions of chapter 54, to carry out the purposes of this section.²⁴

New Mexico

E. it serves the public interest to support public utility investments in cost-effective energy efficiency and load management by removing any regulatory disincentives that may exist and allowing recovery of costs for reasonable and prudently incurred expenses of energy efficiency and load management programs;²⁵

The commission shall identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management and, if found, ensure that they are eliminated in order that public utilities are financially neutral in their preference for acquiring demand or supply-side utility resources.²⁶

Decoupling

California

Prior to restructuring, California had a decoupling mechanism known as the Electric Rate Adjustment Mechanism (ERAM). The ERAM was eliminated in 1996, when the state restructured its electric sector. In 2001, the state legislature mandated a return to decoupling. Public Utilities Code 739.10 states:

²⁴ Connecticut Statutes 16.277.16-19kk. See <http://www.cga.ct.gov/2005/pub/Chap277.htm#Sec16-19kk.htm>

²⁵ New Mexico Statutes, Chapter 62-17-2. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

²⁶ New Mexico Statutes, Chapter 62-17-5. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations.²⁷

From 2002-2005, California's three IOUs developed revenue caps and balancing accounts in order to comply with this provision. The accounts are designed to record certain costs and revenues, and will be trued up each year to that year's authorized revenues. Revenue requirements are adjusted each year based on inflation. Each utility has proposed individual mechanisms for determining annual revenue requirements. The CPUC has approved mechanisms for each utility, based on the initial proposals and, in some cases, settlements with intervenors, as follows:

Southern California Edison:

Excerpts from Decision 04-07-022²⁸:

Section 739.10 (added by Stats. 2001, 1st Ex. Sess., Ch.8, Sec. 10) provides that "[t]he commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations." Pursuant to this statute, in D.02-04-055, the Commission approved a revenue balancing account mechanism that assures recovery of SCE's authorized distribution revenue requirement under the PBR mechanism. SCE proposes in this GRC to utilize such a revenue balancing account during the test year and beyond to adjust for variations in sales. . . .

. . . we note that the need to establish an authorized annual revenue requirement for 2004 and 2005 in connection with the revenue balancing account does not mean, as SCE suggests, that the establishment of a particular post-test year ratemaking mechanism is required to determine annual revenue requirements. In other words, the objective of removing incentives to increase commodity sales does not require that an attrition allowance or other form of revenue requirement adjustment be established. Whether or not it is advisable to do so, it would be possible to apply the authorized test year revenue requirement to the following years. SCE's PTYR proposal will be evaluated on its merits, not on the basis that it is somehow required under Section 739.10 or D.02-04-055.

Whether called attrition or known by some other name, proposals such as SCE's PTYR mechanism have been approved in energy utility rate proceedings on several occasions over the past 20 years, but not invariably so. Attrition allowances for non-test years, and by extension SCE's PTYR proposal, are neither automatically granted nor are they entitlements. They are not intended to insulate utilities from economic pressures that all businesses experience.

We start with the proposition that a utility's opportunity to earn a fair return on the investments made to provide adequate utility service is realized with the adoption of a just and reasonable forecast test year revenue requirement. Then, to judge whether post-test year revenue adjustment provisions are appropriate, we inquire into whether there are, or will be, conditions that might undermine a utility's opportunity to earn its

²⁷ California Public Utilities Code 739.10. See <http://leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=727-755>

²⁸ Full Decision is available at http://www.cpuc.ca.gov/Published/Final_decision/38235.htm#P2659_467920

authorized rate of return after the test year. Such conditions need not be limited to those encountered 20 years ago, when the Commission was approving attrition adjustments because of high costs of utility debt and because the economy was unpredictable and volatile. Interest rates may be lower and the economy may be more stable now, but that does not mean there can be no other conditions that impact the utility's ability to earn a reasonable return.

With a revenue balancing account, variations between recorded revenues and the utility's authorized revenue requirement are tracked for subsequent recovery from, or refund to, ratepayers. Any additional revenues beyond the authorized revenue requirement that result from customer growth or increased usage per customer are returned to customers as a rate decrease. They are not available to offset any cost increases. SCE contends that in order for it to have a fair opportunity to earn its authorized return on equity, we should provide for an increase in the authorized annual revenue requirement so it can recover cost increases caused by customer growth, the need to replace aging infrastructure facilities, and the impact of price inflation on operating expenses.

Regarding the impact of a revenue balancing account, SCE paints only a partial picture by failing to note that the account protects it against any revenue shortfalls that might otherwise occur if usage declines. Nevertheless, even considering the full picture, we are persuaded that the use of a revenue balancing account provides added, though not full, justification for a revenue requirement adjustment mechanism such as those proposed by SCE and Aglet.

The rationale for approving non-test year revenue requirement adjustments is greater in this GRC than we have encountered in recent proceedings where we denied such mechanisms. SCE's financial condition was devastated by the events of 2000 and 2001, and it only narrowly avoided bankruptcy. While SCE's earnings have improved since the worst of the energy crisis in 2000 and early 2001, SCE is still working to regain full creditworthiness, an objective that no party opposes and one that this Commission has repeatedly endorsed. This weighs strongly in favor of adopting a revenue requirement adjustment mechanism for this GRC cycle for both 2004 and 2005.

. . . . To provide SCE with a reasonable opportunity to earn the authorized return on utility investments during this GRC cycle, we will adopt a PTYR mechanism applicable for both 2004 and 2005²⁹.

CONCLUSIONS OF LAW:

48. SCE's revenue balancing account proposal is approved.

49. To judge whether attrition allowances or similar post-test year revenue adjustment provisions are appropriate, we should inquire into whether there are, or will be, conditions that might undermine a utility's opportunity to earn its authorized rate of return after the test year.

²⁹ California Public Utilities Commission Decision 04-07-022, Sec. 10.2 – 10.3 (footnotes omitted). See http://www.cpuc.ca.gov/Published/Final_decision/38235.htm#P2647_463664

50. To provide SCE with a reasonable opportunity to earn the authorized return on utility investments during this GRC cycle, we should adopt a PTYR mechanism applicable for both 2004 and 2005³⁰.

Since Decision 0407022 was issued, SCE has established a Base Revenue Requirement Balancing Account as follows:

1. Purpose.

The purpose of the Base Revenue Requirement Balancing Account (BRRBA) is to record: 1) the difference between SCE's authorized distribution and generation base revenue requirements and recorded revenues from authorized distribution and generation rates; and 2) other amounts as authorized by the Commission. The BRRBA is established in accordance with D.04-07-022.

2. Definitions:

a. Authorized Distribution Base Revenue Requirement:

The Authorized Distribution Base Revenue Requirement (ADBRR) is the most current Commission-authorized Distribution-related base revenue requirement. The current ADBRR is listed below:

Table A
Authorized Distribution Base Revenue Requirement
(\$000)

Effective Date	ADBRR
May 22, 2003	\$ 2,432,380
January 1, 2004	\$ 2,665,448
January 1, 2005	\$ 2,770,383

b. Authorized Generation Base Revenue Requirement:

The Authorized Generation Base Revenue Requirement (AGBRR) is the most current Commission-authorized Generation-related base revenue requirement. The current AGBRR is listed below:

Table B
Authorized Generation Base Revenue Requirement
(\$000)

Effective Date	AGBRR
May 22, 2003	\$ 401,149
January 1, 2004	\$ 675,852
September 7, 2004	\$ 671,712
January 1, 2005	\$ 596,049

c. BRRBA Distribution Revenue:

BRRBA Distribution Revenue shall be determined each month as follows:

³⁰ Ibid. See http://www.cpuc.ca.gov/Published/Final_decision/38235.htm#P3125_609111

1. BRRBA Billed Distribution Revenue:
Shall be determined each month as follows:
 $(A / B) * C$

Where:

A = ADBRR included in rate levels plus the amount consolidated into Distribution rate levels associated with the Distribution Sub-account of the BRRBA.

B = Total Authorized Distribution Revenue Requirement in rate levels, including ADBRR, plus all other Commission authorized distribution-related revenue requirements.

C = Total recorded billed Distribution revenues, adjusted to remove the CARE discount, and CARE surcharge.

Plus: the change (plus or minus) in the amount of BRRBA unbilled Distribution revenue (the reversal of prior month's estimated unbilled revenue, plus the current month's estimate), (BRRBA distribution unbilled revenues will be allocated using the same percentage used to determine BRRBA Billed Distribution Revenue);

Less: a provision for FF&U.

d. BRRBA Generation Revenue:

BRRBA Generation Revenue shall be determined each month as follows:

1. BRRBA Billed Generation Revenue:
Shall be determined each month as follows:
 $(A / B) * C$

Where:

A = AGBRR included in rate levels plus the amount consolidated into Generation rate levels associated with Generation Sub-account of the BRRBA

B = Total Authorized Generation Revenue Requirement in rate levels, including AGBRR, plus all other Commission authorized generation-related revenue requirements

C = Total recorded billed Generation revenues adjusted to remove the impact of 20/20 Rebate Program and Residential Generation Tier 1 and Tier 2 revenue shortfall/surplus that occurs as the result of implementing Resolution E-3897.

Plus: the change (plus or minus) in the amount of BRRBA unbilled Generation revenue (the reversal of prior month's estimated unbilled revenue, plus the current month's estimate), (BRRBA generation unbilled revenues will be allocated using the same percentage used to determine BRRBA Generation Revenue);

Less: a provision for FF&U.

. . . . Pursuant to D.04-01-048, D.04-03-023, and D.04-07-022, SCE shall update its Distribution and Generation Rate levels to reflect the most current Commission adopted revenue requirements in its August Energy Resource Recovery Account (ERRA) application. The balance forecast to be recorded in the Distribution Subaccount of the BRRBA (either overcollected or undercollected) on December 31st of the current year, plus an amount for FF & U, shall be included in the Distribution revenue requirement to either be returned to, or recovered from, SCE's retail electric customers in Distribution rate levels. Likewise, the balance forecast to be recorded in the Generation Sub-account of the BRRBA (either overcollected or undercollected) on December 31st of the current year, plus an amount for FF & U, shall be included in the Generation revenue requirement to either be returned to, or recovered from SCE's retail electric customers in Generation rate levels. Prior to implementing consolidated Commission-authorized

revenue requirements and rate levels to recover those revenue requirements, the BRRBA balance will be updated to reflect the latest recorded balance available.³¹

San Diego Gas & Electric and Southern California Gas:

In March 2005, in Decision 0503023, CPUC adopted a post-test year ratemaking mechanism for SDG&E and So Cal Gas by approving a settlement between the two utilities and several intervenors. Under the agreement, each year's revenue requirement is determined by the previous year's base margin adjusted by the CPI, with minimum and maximum authorized adjustments (Between 3.2 and 4.2 for 2005):

The Base Margin Settlement would ask the Commission to adopt the CPI instead of the Gas and Electric Indices, but it also introduces a limitation. The parties would include a floor and ceiling in the index by setting maximum and minimum adjustments that change annually, differ between SoCalGas and SDG&E, and treat the SoCalGas gas department and the SDG&E gas department differently. We recognize that in order to reach a settlement, parties sometimes compromise a litigated position. We find that the parties have reached a reasonable compromise in light of the record.

Under reasonably foreseeable levels of inflation, the Settlement Agreement will reproduce a level of authorized revenue for each of SoCalGas and SDG&E in each of the three post-test years that is between the level that would have been produced given Applicants' litigation position and the lowest levels produced by the position of any interested party. We find this feature, limits on the adjustment, to be a reasonable outcome in the best interests of the ratepayers. Our objective is to ensure that SoCalGas and SDG&E have adequate revenues to provide safe and reliable service and, in return, that ratepayers can expect those revenues to be used for the safe and reliable operations of SoCalGas and SDG&E. . . .

. . . We recognize that settlements represent a compromise between parties' litigated positions rather than an agreement to any party's specific position. This Settlement is supported by parties representing all various affected interests in this proceeding and represents a fair and reasonable compromise of the issues. We find that the settlements' use of the CPI are reasonable indicators of inflation for SoCalGas and SDG&E for the post-test year period until the next GRC.³²

From the Settlement Agreement:

So Cal Gas' and SDG&E's annual authorized base margin for each of the years 2005, 2006, and 2007 shall be equal to the previous years' authorized base margin, with exclusions as provided herein, times one plus the forecast percentage change in the Consumer Price Index-All Urban Consumers ("CPI") for the upcoming year over the previous year.

³¹ SCE Preliminary Statement YY. See <http://www.sce.com/AboutSCE/Regulatory/tariffbooks/PreliminaryStatements.htm>

³² California Public Utilities Commission D. 05-03-023, Section 6c. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820-05.htm#P186_26137

. . . .Notwithstanding the forecast CPI change, the minimum and maximum authorized adjustments relative to the previous year’s authorized base margin will be as follows:

For SoCalGas:

	<u>2005</u>	<u>2006</u>	<u>2007</u>
Minimum	2.0%	2.5%	3.3%
Maximum	3.0%	3.5%	4.3%

For SDG&E:

	<u>2005</u>	<u>2006</u>	<u>2007</u>
Minimum	3.2%	3.5%	3.8%
Maximum	4.2%	4.5%	4.8% ³³

SoCalGas and SDG&E request "balancing", i.e., balancing account treatment, to ensure there is no unintended over- or undercollection of the adopted base margin revenues. The revenue is subject to risk caused primarily by differences between the forecast and actual sales/throughput volumes in kilowatt-hours or therms. Without a balancing account process overcollections are a risk to ratepayers and undercollections are a risk to the applicants. SDG&E argues balancing would satisfy the requirements of § 739.10 for the electric department, and would be consistent with D. 97-07-054, which protected SoCalGas from sales/throughput risk. SDG&E asks that this balancing process be extended to its gas department, notwithstanding that the Commission declined this protection in D. 99-05-030. No one opposed these requests. As noted in this decision, there are many similarities in the operations of SoCalGas and SDG&E, especially in the development of these rate cases and the daily management of the companies that would support aligning the revenue balancing protection for both gas departments and the electric department. We will continue revenue balancing for SoCalGas' gas operations and extend the process to both SDG&E's electric and gas operations.³⁴

Decision 0503023 also approved a sharing mechanism between customers and shareholders, as follows³⁵:

<u>Earnings Band</u>	<u>Shareholders</u>	<u>Ratepayers</u>
0 - 50	100%	0%

³³ Settlement Agreement Regarding Phase II Base Margin Issues, p. 10. See <http://www.cpuc.ca.gov/PUBLISHED/Graphics/44824.PDF>

³⁴ California Public Utilities Commission D. 05-03-023, Section 7c. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820-06.htm#P211_34446. Footnotes omitted.

³⁵ Ibid. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820-18.htm#P1138_120902

51 – 100	75%	25%
101 – 125	35%	65%
126 – 150	45%	55%
151 – 175	55%	45%
176 – 200	65%	35%
201 – 300	75%	25%
Over 300	Suspension	

Pacific Gas & Electric

In Decision 04-05-055 (May 27, 2004), the CPUC approved a settlement regarding PG&E's GRC. As part of this settlement, and pursuant to Public Utilities Code 739.10, PG&E was required to implement the DRAM (Distribution revenue adjustment mechanism) and UGBA (Utility Generation Balancing Account) as revenue adjustment mechanisms to ensure that over- or under-collections of generation and distribution revenues did not occur.

The CPUC adopted revenue requirements and approved attrition adjustments for the years 2004, 2005, and 2006 tied to the level of inflation, as measured by CPI-All-Urban Consumers, to provide PG&E the opportunity to earn its authorized rate of return in the attrition years:

The Distribution Settlement adopts a 2003 electric distribution revenue requirement of approximately \$2,493 million and a gas distribution revenue requirement of \$927 million. The Settling Parties agree that PG&E's revenues at present rates are \$2,257.44 million for electric distribution and \$874.895 million for gas distribution. Therefore, the Distribution Settlement would result in an increase from present rates of approximately \$236 million for electric distribution and \$52 million for gas distribution. . . .

. . . The Distribution Settlement reflects the Settling Parties' agreement to defer the test year for PG&E's next GRC until 2007, and to provide PG&E attrition adjustments for 2004, 2005, and 2006, based upon an agreed-upon formula and implemented through advice letter filings. The proposed annual electric and gas distribution attrition adjustments for 2004 and 2005 would be equal to the previous year's authorized revenue requirement times the forecast change in the CPI for All Urban Consumers. For 2006, the proposed annual electric and gas distribution attrition adjustments would be equal to the previous year's authorized revenue requirements times the forecast change in CPI-All Urban Consumers plus one percent.

Notwithstanding the forecast change in CPI-All Urban Consumers, the Distribution Settlement provides for minimum and maximum revenue requirement attrition adjustments as follows:

	2004	2005	2006
Minimum	2.0%	2.25%	3.0%
Maximum	3.0%	3.25%	4.0%

The Distribution Settlement would result in 2004, 2005, and 2006 estimated attrition increases of \$62 million, \$64 million, and \$89 million for electric distribution and \$23 million, \$24 million, and \$33 million for gas distribution.

The Generation Settlement also provides for annual electric generation attrition increases for 2004, 2005, and 2006, equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers, including a minimum increase of 1.5% and a maximum of 3% for 2004 and 2005, and an additional 1% for 2006³⁶

As part of the settlement, PG&E has established two balancing accounts, a Distribution Revenue Adjustment Mechanism (DRAM) and a Utility Generation Balancing Account (UGBA). Both accounts are trued up annually³⁷.

Connecticut

Connecticut's 2005 Energy Independence Act states that:

The Department of Public Utility Control shall conduct an investigation on how best to decouple the earnings of natural gas companies and other public service companies from their sales to promote the state's energy policy. The department shall report, in accordance with the provisions of section 11-4a of the general statutes, its findings and recommendations for legislation to the joint standing committee of the General Assembly having cognizance of matters relating to energy and technology on or before January 1, 2006.³⁸

Maryland: Baltimore Gas & Electric

Baltimore Gas & Electric employs a decoupling mechanism for residential and general service gas customers:

The Delivery Price under Schedules D and C [residential service and general service] is adjusted to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the change in the number of customers from the test year level. The change in revenues associated with the Customer Charge is the change in number of customers multiplied by the Customer Charge for the rate schedule. The change in revenues associated with throughput is the test year average use per customer multiplied by the net number of customers added since the like-month during the test year and multiplying that product by the Delivery Price for the rate schedule. The change in revenues associated with Customer Charge and throughput is added to test year revenue to restate test year revenues for the month to include the revised values. Actual revenues collected for the month are compared to the restated test year revenues and any difference is divided by estimated sales for the second succeeding month to obtain the

³⁶ California Public Utilities Commission Decision 05-05-055, Section 7.1. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086-06.htm#P300_37806

³⁷ Accounting procedures are available from PGE's tariff sheets at <http://www.pge.com/tariffs/pdf/EPSCZ.pdf> (DRAM) and <http://www.pge.com/tariffs/pdf/EPSCG.pdf> (UGBA)

³⁸ Energy Independence Act, Section 21. See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>.

adjustment to the applicable Delivery Price. Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month. The Monthly Rate Adjustment is calculated separately for Schedule D, Schedule C, excluding Daily Metered customers, and Schedule C Daily Metered customers only. Details of the calculation of the billing adjustment are filed monthly with the Public Service Commission.³⁹

North Carolina

In November, 2005, North Carolina's three major gas utilities were granted a decoupling mechanism. The North Carolina Utility Commission Order states:

In its Petition, the Company⁴⁰ proposed to implement a new mechanism, denoted as a Conservation Tariff, for residential and commercial customers . . . under the proposed Conservation Tariff mechanism, the Company's ability to recover its margin would be "decoupled" from the usage patterns of its customers, thereby allowing it to promote conservation measures without harming its ability to remain an economically viable entity.

While conservation benefits customers and the general public, the practical reality is that it has the potential to do financial harm to the utility and its shareholders. The decoupling of recovery of margin from usage will better align the interests of the Company and its customers with respect to conservation, and this is particularly important today. Reconciling this inherent conflict between the utility and its customers can help open opportunities for conservation of energy resources, savings for customers, and downward pressure on wholesale gas prices, while also helping the utility recover its margin and earn a reasonable return. Other ways to address the conflict include higher fixed customer charges or more frequent rate cases, but fixed charges are unpopular with customers who feel that their bill should be tied to usage, and rate cases are lengthy and expensive proceedings that impose costs on both customers and the utility. The CUT⁴¹ allows for a continuation of a highly volumetric rate structure and lower fixed customer charges. The Commission does not agree with the Attorney General's argument that the CUT will penalize customers for conserving. Even if conservation results in increments, the increment should offset only a portion of the conservation savings. Neither does the Commission agree with the Attorney's [sic] General's argument that there is no good reason for the CUT to apply to residential and commercial customers, but not industrial customers. The different usage patterns and tariffs of industrial customers provide good cause for such a distinction.

The Commission must also consider the effect of the CUT on shareholder risk. Piedmont agrees that there is no evidence of reduced risk to shareholders, but the Commission disagrees on the basis of the Company's own case. The CUT will preserve the rate case assumptions as to customer usage and make corresponding rate adjustments. In a period

³⁹ Baltimore Gas & Electric Monthly Rate Adjustment tariff rider. See <http://www.bge.com/portal/site/bge/menuitem.6b0b25553d65180159c031e0da6176a0/>

⁴⁰ Piedmont Natural Gas Company

⁴¹ The initial Conservation Tracker was renamed the Customer Utilization Tracker.

of declining per-customer usage, a mechanism that decouples recover of margin from usage, without requiring the utility to file frequent rate cases or increase unpopular fixed charges, clearly reduces shareholder risk.

In summary, the Commission . . . concludes that the CUT is fair and reasonable to the extent that it should be approved as an experimental tariff limited to no more than 3 years from the effective date of the rates herein . . . Further, during the life of the CUT, Piedmont shall contribute \$500,000 per year toward conservation programs and shall work with the Attorney General and the Public staff to develop appropriate and effective conservation programs to assist its residential and commercial customers.⁴²

Oregon: Northwest Natural Gas

In Order 02-634, the Oregon Public Utilities Commission (OPUC) decoupled Oregon NW Natural Gas' revenues from sales by approving a settlement agreement⁴³ between NW Natural and other parties:

Also on October 1, 2002, NW Natural will implement a partial decoupling mechanism, under which it will defer and subsequently amortize 90 percent of the margin differentials in the residential and commercial customer groups. Marginal differentials are the margins associated with the difference between each group's weather-normalized usage and usage baseline. The deferral for each monthly period would be a credit (refund) if the calculation is positive or a debit (charge) if the calculation is negative. The per-therm distribution margin for each customer group for initial use under the stipulation will be the margins developed in docket UG 132. For residential customers, this margin is \$0.34055 per therm. For commercial customers, this margin is \$0.21692 per therm. The per-therm distribution margins would be replaced by new margins adopted by the Commission in NW Natural's rate case described below.

The stipulating parties emphasize that the decoupling mechanism will be applied to weather-normalized usage. When the company calculates variations from baseline volumes each month, it will adjust actual volumes to account for abnormal weather using the approach to weather normalization adopted in UG 132. The decoupling adjustments would be determined based on a monthly comparison of weather-normalized usage to baseline volumes resulting from actual customer counts. NW Natural will defer and amortize 90 percent of margin differentials due to each month's decoupling adjustments, with interest.⁴⁴

After our review, we agree with NW Natural, CADO, and Staff that the stipulation should be adopted without modification. As the parties note, the agreement is a compromise that recognizes the interests of all the parties that participated in this docket, not just those that signed the stipulation. While not incorporating a true decoupling

⁴² Nov. 3, 2005 Order of the North Carolina Utilities Commission, p. 20-24. See

[http://ncuc.commerce.state.nc.us/cgi-](http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=JAAAAA70350B)

[bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=JAAAAA70350B](http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=JAAAAA70350B)

⁴³ Full Agreement is found in Appendix A of Order 02-634, available at

<http://apps.puc.state.or.us/orders/2002ords/02-634.pdf>.

⁴⁴ Order 02-634, p. 3, available at <http://apps.puc.state.or.us/orders/2002ords/02-634.pdf>

mechanism, the elasticity adjustment and partial decoupling mechanism substantially accomplishes NW Natural's goal of better aligning shareholder and customer interests. The conceptual purpose of decoupling has always been to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict. The stipulated mechanism will allow NW Natural to provide customer service support and information related to energy efficiency without causing a negative financial impact on its shareholders.⁴⁵

The Model Rule

The Regulatory Subgroup of the Mid-Atlantic Distributed Resources Initiative (MADRI) has drafted a revenue stability mechanism designed to decouple electric distribution utility sales and profits:

1. Applicability

This Rider is applicable to the following rate schedules:
[list applicable rate schedules].

2. Definitions

2.1. **Test Year Revenues** means the expected revenues for the applicable rate schedule as calculated when the rate schedule rates were last set, excluding the adjustments made in this rate schedule.

2.2. **Revenue Stability Demand Charge Adjustment Factor** means the additional demand charge or demand credit provided for in this rate schedule and to be applied to customers' bills during the Billing Month.

2.3. **Expected Demand Charge Adjustment Factor Revenues** means the amount of revenues for demand charges that had been expected to be collected during the Reference Month through the application of the Revenue Stability Demand Charge Adjustment Factor, based on the use of the estimated billing units used in the computation of the Revenue Stability Demand Charge Adjustment Factor for the Reference Month,

2.4. **Actual Demand Charge Adjustment Factor Revenues** means the amount of revenues for demand charges actually collected during the Reference Month, based on the actual billings units used in computation of bills sent to customers during the Reference Month.

2.5. **Change in Demand Charge Revenues** means the test year average use per customer (measured in kW demand) multiplied by the change in number of customers since the like-month during the test year and multiplied by the demand charge for the applicable rate schedule and multiplied by the Demand Charge K Factor.

⁴⁵ Ibid., p. 9

2.6. **Revenue Stability Energy Charge Adjustment Factor** means the additional energy charge or energy credit provided for in this rate schedule and to be applied to customers' bills during the Billing Month.

2.7. **Expected Energy Charge Adjustment Factor Revenues** means the amount of revenues for energy charges that had been expected to be collected during the Reference Month through the application of the Revenue Stability Energy Charge Adjustment Factor, based on the use of the estimated billing units used in the computation of the Revenue Stability Energy Adjustment Factor for the Reference Month,

2.8. **Actual Energy Charge Adjustment Factor Revenues** means the amount of revenues for energy charges actually collected during the Reference Month, based on the actual billings units used in computation of bills sent to customers during the Reference Month.

2.9. **Change in Energy Charge Revenues** means the test year average use per customer (measured in kWh multiplied by the change in number of customers since the like-month during the test year and multiplied by the energy charge for the applicable rate schedule and multiplied by the Energy Charge K Factor.

2.10. **Filing Month** means the month in which a Revenue Stability Adjustment Reconciliation filing is due.

2.11. **Reference Month** means the month that is two months prior to the filing month.

2.12. **Reference Month Revenues** means the actual revenues billed during the Reference Month.

2.13. **Billing Month** means the month that is the second succeeding month after the Filing Month and is the month during which the Revenue Stability Adjustment is applied to customers' bills.

2.14. **Estimated Customer Charge Billing Units** means the billings units expected to be used for customer charges on customers' bills during the Billing Month.

2.15. **Estimated Demand Billing Units** means the billing units expected to be used for demand charges on customers' bills during the Billing Month.

2.16. **Estimated Energy Billing Units** means the billing units expected to be used for energy charges on the customers' bills during the Billing Month.

2.17. **Average Energy Revenue** means the Test Year Energy Billing Units divided by the number of Test Year Customers and is computed separately for each billing class of customers.

2.18. **Incremental Energy Revenues** means the change in Test Year Energy Billing Units during the Test Year divided by the change in the number of Test Year Customers during the Test Year and is computed separately for each billing class of customers.

2.19. **Energy Charge K Factor (K_e)** means the Average Energy Revenue divided by Incremental Energy Revenues and is computed separately for each billing class of customers.

2.20. **Average Demand Revenue** means the Test Year Demand Billing Units divided by the number of Test Year Customers and is computed separately for each billing class of customers.

2.21. **Incremental Demand Revenues** means the change in Test Year Demand Billing Units during the Test Year divided by the change in the number of Test Year Customers during the Test Year and is computed separately for each billing class of customers.

2.22. **Demand Charge K Factor (K_d)** means the Average Energy Revenue divided by Incremental Energy Revenues and is computed separately for each billing class of customers.

3. Revenue Stability Adjustment Factor

In addition to the amounts otherwise due from the customer under the customer's applicable rate schedule, the customer shall pay an additional amount, in the case of a positive adjustment, or receive a credit, in the case of a negative adjustment, equal to the Customer Charge Revenue Stability Adjustment Factor, the Demand Charge Revenue Stability Adjustment Factor and the Energy Charge Revenue Stability Adjustment Factor as calculated in Section 4 of this rate rider multiplied by the customer's customer, demand and energy billing units, respectively, appearing on the actual bill to which each such adjustment factor is being applied.

4. Calculation of Revenue Stability Adjustment Factors

4.1. **Customer Charge Revenue Stability Adjustment Factor** – The Customer Charge Revenue Stability Adjustment Factors is equal to the sum of the amounts resulting from the calculations in Sections. 4.4.1.1 and 4.4.1.2 below:

4.1.1. **Change in Customer Charge Revenues** – The Change in Customer Charge Revenues divided by Estimated Customer Charge Billing Units.

4.1.2. **Reconciliation of Differences Between Previously Estimated Customer Charge Billing Units and Actual Customer Charge Billing Units for the Reference Month** – An amount equal to the difference between Expected Customer Charge Adjustment Factor Revenues and Actual Customer Charge Adjustment Factor Revenues divided by Estimated Customer Charge Billing Units.

4.2. **Demand Charge Revenue Stability Adjustment Factor** -- The Demand Charge Revenue Stability Adjustment Factor is equal to the sum of the amounts resulting from the calculations in items 4.2 and 4.2.1 below:

4.2.1. **Change in Demand Charge Revenues** – The Change in Demand Charge Revenues divided by Estimated Demand Charge Billing Units.

4.2.2. **Reconciliation of Differences Between Previously Estimated Demand Billing Units and Actual Demand Billing Units for the Reference Month** – An amount equal to the difference between Expected Demand Adjustment Factor Revenues and Actual Demand Adjustment Factor Revenues divided by Estimated Demand Charge Billing Units.

4.3. **Energy Charge Revenue Stability Adjustment Factor** -- The Energy Charge Revenue Stability Adjustment Factor is equal to the sum of the amounts resulting from the calculations in items 4.3.1 and 4.3.2 **Error! Reference source not found.** below:

4.3.1. **Change in Energy Charge Revenues** – The Change in Energy Charge Revenues divided by Estimated Energy Charge Billing Units.

4.3.2. **Reconciliation of Differences Between Previously Estimated Billing Units and Actual Billing Units for the Reference Month** – An amount equal to the difference between Expected Energy Charge Adjustment Factor Revenues and Actual Energy Charge Adjustment Factor Revenues divided by Estimated Energy Charge Billing Units.

5. Monthly Filing

A Revenue Stability Adjustment Factor Reconciliation shall be filed monthly with the Public Service Commission (Commission) and become part of the Company's approved rates and tariffs, subject to any other rules and procedures of the Commission.⁴⁶

Bonus Rate of Return

Nevada

Nevada allows a bonus rate of return for DSM investments 5% higher than authorized rates of return for supply investments:

1. All costs of implementing programs for conservation and demand management must be accounted for in the books and records of a utility separately from amounts

⁴⁶ Model Revenue Stability Rate Rider, Regulatory Subgroup of the Mid-Atlantic Distributed Resource Initiative. See <http://www.raponline.org/MADRI/Archives/000044.html>

attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. A utility may, pursuant to subsection 3, recover all prudent and reasonable costs incurred in implementing programs for conservation and demand management that have been approved by the Commission as part of the action plan of the utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing and evaluation. The utility may recover approved costs associated with monitoring and evaluating programs for conservation and demand management through a general rate case.

3. To recover costs incurred in implementing programs for conservation and demand management, a utility must:

(a) Calculate, on a monthly basis, the costs incurred in implementing each program since the end of the test period or period of certification in its last proceeding to change general rates.

(b) Record the cost of implementing each program, as calculated pursuant to paragraph (a), in a separate subaccount of Account 182.3 (Other Regulatory Assets) for each program and make an appropriate offset to other subaccounts.

(c) Maintain subsidiary records of the subaccounts of Account 182.3 for each program. These records must clearly delineate all costs incurred by the utility in implementing each program approved by the Commission.

(d) Apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the balance in the subaccounts of Account 182.3 for each program not included in the rate base.

(e) Clear any balance accumulated in the subaccounts of Account 182.3 for each program as a component of an application by the utility to change general rates as follows:

(1) The Commission will adjust the rate to amortize the balance over a period determined by the Commission to be appropriate for clearing the account and consistent with the life of the investment.

(2) The utility must begin amortizing costs on the date that the change in general rates becomes effective.

(3) The utility must include the balance in the subaccounts of Account 182.3 for each program, including carrying charges, in the rate base as of the date that ends the test period used in the utility's application to change general rates or as of the date that ends the period of certification, whichever is later.

(4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of Account 182.3 for each program that the utility has carried out on the authorized return on equity plus 5 percent.⁴⁷

Lost Revenue Recovery

Kentucky

Kentucky allows lost revenue recovery for both electric and gas DSM programs. Recovery mechanisms are determined on a case-by-case basis. The enabling statute reads:

⁴⁷ Nevada Administrative Code 704.9523. See <http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9523>

A proposed demand-side management mechanism including:

- (a) Recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs;
- (b) Obtain incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs; or
- (c) Both of the actions specified

may be reviewed and approved by the commission as part of a proceeding for approval of new rate schedules initiated pursuant to KRS 278.190 or in a separate proceeding initiated pursuant to this section which shall be limited to a review of demand-side management issues and related rate-recovery issues as set forth in subsection (1) of this section and in this subsection.⁴⁸

In Administrative Case 341, the Kentucky Public Service Commission reiterated its authority to approve DSM programs and cost recovery mechanisms, on a case-by-case basis:

The Commission has considered the responses of the parties. . . [W]e have concluded that the utilities should consider and pursue cost-effective DSM in the development of future resource plans just as they would consider any supply-side resource. House Bill 501 has given the Commission the statutory authority to establish cost recovery mechanisms and financial incentives to encourage a utility's use of DSM. The Commission will judiciously and carefully exercise that authority.

While there are some areas of consensus among the parties, particularly on the matter of methods for creating financial incentives for DSM, the Commission will not prescribe a generic approach or methodology for recovering DSM program costs and lost revenues or creating financial incentives for the implementation of cost-effective DSM programs. Utilities should have the flexibility not only to develop utility-specific DSM programs but also utility-specific cost recovery and financial incentive mechanisms.⁴⁹

Performance Incentives

Arizona

The shareholders of Arizona Public Service will be allowed a performance incentive for DSM program results, according to a 2005 Arizona Corporation Commission decision.

Funding for DSM comes in both base rates (\$10 million per year) and through implementation of an adjustor (average of \$6 million per year). DSM funding will be used for “approved eligible DSM-related items,” including “energy-efficiency DSM

⁴⁸ Kentucky Revised Statutes, Chapter 278, Title 285. See <http://www.lrc.ky.gov/KRS/278-00/285.PDF>

⁴⁹ Administrative Case 341, 7/14/1994 Order. See

http://psc.ky.gov/order_vault/Orders_1994/19000341_07141994.pdf, p. 4

programs,” a performance incentive, and low income bill assistance. APS is obligated to spend \$13 million in 2005 on DSM projects.⁵⁰

In the Decision, the footnote to the phrase “a performance incentive” directs the reader to paragraph 45 of the Settlement, which is appended to the Decision. It reads:

APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with paragraph 41. Such performance incentive will be capped at 10% of the total amount of DSM spending, inclusive of the program incentive, provided for in the Agreement (e.g., \$1.6 million out of the \$16 million average annual spending referenced in paragraphs 40 and 44 or \$4.8 million over the initial three-year period). Any such performance incentive collected by APS during a test year will be considered as a credit against APS’ test year base revenue requirement. The specific performance incentive will be set forth in and approved as part of the Final Plan referenced in paragraph 48.⁵¹

Connecticut

Each year, the two electric utilities managing C&LM programs are eligible for “performance management fees,” that is, incentives tied to performance goals approved by the ECMB and DPUC, including lifetime energy savings and demand savings, and other measures. Incentives are available for a range of outcomes from 70-130% of pre-determined goals. In 2004 the two utilities collectively reached 130% of their energy savings goals, and 124% of their demand savings goals. They received performance management fees totaling \$5.27 million. The 2006 joint budget anticipates \$2.9 million in performance incentives.

Massachusetts

In Docket 04-11, the Massachusetts Department of Transportation and Energy (DTE) updated NSTAR’s shareholder incentives for efficiency as follows:

NSTAR Electric proposed to (1) fix the after-tax shareholder incentive at five percent; (2) set the threshold level of performance at 75 percent; (3) set the exemplary level of performance at 110 percent; and (4) slightly reallocate the weights assigned to the savings and value determinants.

. . . Under its proposal, the Company’s shareholder performance incentive would amount to approximately \$3.025 million based on energy efficiency expenditures of about \$60.5 million in 2004. Under its threshold and exemplary proposal, NSTAR Electric’s shareholder incentive payment amount would range from 75 percent to 110 percent of its 2004 energy efficiency expenses. NSTAR Electric noted that a shareholder incentive would not be earned if an energy efficiency program failed to achieve the threshold level of 75 percent of design level performance (id.). NSTAR Electric stated that even if an energy efficiency program accomplished more than 110 percent of design level

⁵⁰ Arizona Corporation Commission Decision No. 67744, April 2005. See <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>, page 20.

⁵¹ <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>, paragraph 45 of Appendix A

performance, the shareholder incentive for such a program would nonetheless be capped at the 110 percent level.

. . . In determining incentive levels, the Department must reach a balance between two objectives: (1) promoting effective programs, and (2) protecting the interest of ratepayers. While NSTAR Electric's proposed five percent after-tax rate exceeds the rate now provided in the DTE Guidelines, it is near the middle of the range that DOER proposed in D.T.E. 98-100, and this rate was approved for NSTAR Electric's 2003 Energy Efficiency Plan. The Department reaffirms that an incentive must be large enough to promote good program management, but small enough to leave almost all of the energy efficiency funds to directly serve customers. The Company's proposal balances these two objectives, and is consistent with DOER information that the Department used in formulating the DTE Guidelines.

. . . NSTAR Electric raised the threshold performance level from the 70 percent approved in D.T.E. 03-48, to 75 percent, which is now in conformance with the D.T.E. Guidelines at § 5.2. Also in D.T.E. 03-48, at 13, the Department approved the use of an exemplary performance level of 110 percent of design level for use in calculation of shareholder incentives for 2003. In consideration of Department precedent, DOER's conclusions, and the support of the energy efficiency stakeholders, the Department finds that the Company has demonstrated the reasonableness of its proposal to set the exemplary performance level at 110 percent of performance goals. Accordingly, the Department accepts the Company's proposal to establish a threshold performance level of 75 percent and exemplary performance level of 110 percent of design level.⁵²

Minnesota

In 1999, nine Minnesota utilities, the Minnesota Department of Commerce, the Izaak Walton League of America, and the Center for Energy and the Environment jointly submitted "Joint Proposal for a Shared-Savings DSM Financial Incentive Plan," which was approved by the Minnesota Public Utilities Commission in 2000⁵³. Under the proposal, utilities receive a percentage of total net benefits resulting from Conservation Improvement Plan (CIP) expenditures when certain performance levels are met or exceeded.

1) Net Benefits

Net benefits will be calculated by subtracting each utility's CIP costs from the avoided costs resulting from each utility's CIP investment. The estimated avoided costs per unit of energy or demand saved will remain constant for the duration of an approved biennial CIP.

2) Incentive Trigger

As each utility approaches its energy-savings goal, it will begin to earn an incentive. The Commissioner of the Department of Commerce, the Public Utilities Commission, and the state's minimum statutory spending requirement determine the energy-savings goal for

⁵² Docket 04-11. See <http://www.mass.gov/dte/electric/04-11/819order.pdf>

⁵³ The Joint Proposal was approved on April 7, 2000 in Docket E,G-999/CI-98-1759, Order Approving Demand Side Management Financial Incentive Plans

each utility's DSM financial incentive plan. For incentive purposes, the goal is determined by the equation:

$$\frac{\text{Approved Energy Savings Goal}}{\text{Approved CIP Budget}} \quad * \quad \text{Minimum Spending Level}$$

If a utility reaches this level, it is said to have met 100% of its energy-savings goal. At every percentage point above 90% of goal, a utility would receive an increasing percentage of the total net benefits resulting from CIP investments. . . Utilities only receive a significant incentive once they are exceeding goals based on statutory requirements. Utilities will receive a small incentive for attaining 91% to 100% of the goal. This feature is included in the incentive to ensure that the utility receives an incentive large enough to move beyond 100% of its energy-savings goal. . .

This feature also motivates utilities to minimize the costs of achieving energy-savings goals. As a utility reduces its costs it is able to increase the amount of net benefits achieved and, thus, the amount of net benefits it receives as an incentive.

3) Cap on the Incentive for 1999

An absolute cap on the incentive will be set at the lower of

- 30% of a utility's approved CIP expenditures, or
- 30% of a utility's actual CIP expenditures.

...
The 30% cap is reasonable for two reasons. First, it is only achieved after a utility attains extraordinary results. . . Each utility has to significantly surpass the portion of energy-savings goal approved by the Commissioner of the Department of Commerce . . . that can be achieved at minimum statutory spending levels before receiving a substantial incentive. Second, the incentive level is significant at higher energy-savings goals. The size of the incentive will help ensure that a utility is motivated to achieve additional amounts of cost-effective energy savings.⁵⁴

New Hampshire

In 1999, the New Hampshire Energy Efficiency Working Group proposed a shareholder incentive mechanism (adopted by the NHPUC in November 2000):

The Group recommends that utilities be entitled to earn shareholder incentives. The shareholder incentive approach agreed to by the Group is based on the performance of the programs measured in terms of their actual cost-effectiveness and energy savings relative to the projected cost-effectiveness and energy saving savings, respectively. Separate target incentives are proposed for the residential and C/I sectors set at 8% of the total

⁵⁴ *Joint Proposal for a Shared-Savings DSM Financial Incentive Plan*, In the Matter of Requests to Continue Demand-Side Management (DSM) Financial Incentives Beyond 1998 Resulting From Docket No. E,G-999/CI-98-179. p. 2-3

program and evaluation budgets for each sector. Superior performance could be rewarded by up to 12% of the planned sector budgets.⁵⁵

The mechanism is as follows:

- 1) The proposed shareholder incentive is a sliding scale incentive with two components. The first, *the cost-effectiveness component*, is based on the relationship between the projected New Hampshire Cost-Effectiveness test (NHCE) and the actual year-end NHCE. The second, *the energy savings component*, is based on the relationship between the projected lifetime kWh savings from installed measures (planned savings) and the lifetime kWh savings from actual installations (installed savings).
- 2) There will be two separately calculated incentives – one for the combined programs in the *residential sector* and one for the combined programs in the *commercial/industrial (C/I) sector*.
- 3) Target or Design Performance
 - a) In each sector, a utility that achieves an actual NHCE equal to the projected NHCE and installed savings equal to the planned savings earns a before tax incentive of 8.0% of its planned energy efficiency program budget for that sector.
 - b) The proposed shareholder incentive will be calculated as follows:
 - i) Residential Sector Incentive = $[\text{actual NHCE} \div \text{projected NHCE}] * [4\% * \text{residential planned energy efficiency budget}]$, plus $[\text{installed savings} \div \text{planned savings}] * [4\% * \text{residential planned energy efficiency budget}]$
 - ii) C/I Sector Incentive = $[\text{actual NHCE} \div \text{projected NHCE}] * [4\% * \text{C/I planned energy efficiency budget}]$ plus $[\text{installed savings} \div \text{planned savings}] * [4\% * \text{C/I planned energy efficiency budget}]$
 - c) A utility will not earn anything on the cost-effectiveness component of its incentive in a sector if the actual NHCE for the combined programs in that sector is less than 1.0
 - d) A utility will not earn anything on the energy savings component of its incentive in a sector if the actual energy savings for the combined programs in that sector is less than 65% of its planned energy savings.
 - e) A utility's incentive in a given sector will be capped at 12% (before tax) of its planned energy efficiency budget. There is no cap on either component of the incentive as long as the combined incentive for any sector does not exceed 12% of that sector's planned budget.
 - f) "For incentive calculation purposes only, planned energy efficiency budget" is defined as the total program budget minus shareholder incentives and lost fixed cost recovery, if any.

⁵⁵NHPUC Order 23-574, issued November 2000. See <http://www.puc.state.nh.us/Regulatory/Orders/2000ords/23574e.pdf>

- g) The avoided costs used in calculating the actual NHCE shall be those used to calculate the Commission-approved projected NHCE.
- h) This incentive mechanism shall remain in place through the end of the transition service period of the last utility to introduce retail choice. At that time, the incentive structure will be revisited, along with the over-riding review of energy efficiency programs.
- i) The percentage incentive rates provided for in this proposal may be adjusted in the event of an extended period of either significant inflation or deflation following the effective date of this proposal.
- j) Any variance in spending for any individual program of 20% under or over budget shall require Commission approval.
- k) Final annual shareholder incentives will be determined retrospectively.⁵⁶

Nevada

Nevada’s Commission is authorized to use the following mechanism to encourage investment in “priority resources”, which may include efficiency (or other resources so designated by the Commission).

1. The Commission may, upon the request of a utility or an intervening party pursuant to subsection 2 or upon its own motion, make a determination as to whether to designate a facility of the utility as a critical facility. Such a determination may be made in conjunction with an order issued by the Commission pursuant to subsection 1 of [NAC 704.9494](#) or in another proceeding on the matter.
2. A utility and any party granted intervener status may request that the Commission designate a facility of the utility as a critical facility for the purpose of:
 - (a) Protecting reliability;
 - (b) Promoting diversity of supply and demand side sources;
 - (c) Developing renewable energy resources;
 - (d) Fulfilling specific statutory mandates;
 - (e) Promoting retail price stability; or
 - (f) Any combination of paragraphs (a) to (e), inclusive.

Such a request must be accompanied by supporting analysis and documentation.

3. If the Commission designates a facility as a critical facility, the utility may request that incentives associated with that facility be included in rates in an application to change general rates filed pursuant to [NAC 703.2201](#) to [703.2481](#), inclusive. The incentives may include, without limitation:
 - (a) Earning an enhanced return on equity on the designated critical facility over the life of the facility;

⁵⁶ “Report to the New Hampshire Public Utilities Commission on Ratepayer-Funded Efficiency Issues in New Hampshire”, New Hampshire Energy Efficiency Working Group, 1999. pp.27-28. See <http://www.raabassociates.org/main/projects.asp?proj=11&state=Completed>

- (b) The inclusion in the rates of construction work in progress associated with the designated facility; and
- (c) Designating costs incurred to construct the designated critical facility in a regulatory asset account, to be recorded as a subaccount to Account 182.3 (Other Regulatory Assets). The utility may recover the regulatory asset pursuant to subsection 3 of [NAC 704.9523](#).⁵⁷

Vermont

Efficiency Vermont, the state's "Energy Efficiency Utility" (EEU), receives performance incentives for meeting or exceeding specific goals. The following is excerpted from the 2000-2002 contract between Vermont's Public Service Board (PSB) and the EEU contract administrator, Vermont Energy Investment Corporation:

1. Overview

The *Contractor* and the *Board* agree that a portion of payments to the *Contractor* shall be based on the *Contractor's* performance in achieving the *Board's* objectives and successfully delivering the *Core Programs*. The *Contractor* can earn up to **\$795,000** in performance incentives for successfully meeting program performance indicators that are defined in this Attachment. The *Contractor* shall submit annual claims for Performance Awards, according to the schedule, documentation, and verification processes outlined in this Attachment. The *Contract Administrator* will verify the *Contractor's* claim for Performance Awards and make a recommendation to the *Board*; the *DPS* will provide input for specified indicators as described in this Attachment (see Paragraph 4).

Payment of any earned Performance Awards (up to a maximum of \$795,000) shall be made at the conclusion of this *Agreement*. Payment will be made in two installments: (1) January 15, 2003, for any Performance Awards earned for years 2000 and 2001; and (2) June 2, 2003, for any Performance Awards earned for the year 2002.

The *Contractor's* performance incentive mechanism is designed to reward superior performance by the *Contractor* in the overall administration and delivery of *Core Programs* and includes three major categories or types of incentives, with specific performance indicators that will govern the award of the incentives:

Program Results Incentives

Program Results Incentives reward the *Contractor* for successfully accomplishing aggressive targets for direct market impacts (e.g., electricity savings, lifetime resource benefits, cost savings, market penetration of specific technologies or equipment, and successful leveraging of ratepayer dollars).

Market Effects Incentives

Market Effects Incentives reward the *Contractor* for demonstrated significant market transformation that has been achieved through the *Work*.

Activity Milestone Incentives

⁵⁷ NAC 704.9484, available at <http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9484>

Activity Milestone Incentives reward the *Contractor* for achieving milestones that involve exemplary performance for rapid start-up and/or infrastructure development (e.g., program tracking and information management systems), timely and smooth transition to statewide programs from existing utility efforts, major improvements to existing *Core Programs* or successful development, introduction, and delivery of new *Core Programs*.

This performance incentive mechanism is intended to reward the *Contractor* for successfully accomplishing cross-program activities and for achieving superior performance across the portfolio of *Core Programs* as well as for achieving specific objectives for individual *Core Programs*.

Overall weights and dollars allocated to the various types of performance indicators are shown in Table C-1 below.

Performance Indicator	Total Amount of Award	Overall Weight	Amount of Total Award Eligible to be Earned In Each Year of the Agreement		
			2000	2001	2002
1. Program Results Incentives					
A. Annual Electricity Savings	\$198,750	25%	all three years		
B. Electricity Savings for Projects under Development	\$39,750	5%	\$0	\$0	\$39,750
C. Total Resource Benefits	\$119,250	15%	total amount earned across all three years		
D. Individual and Cross-Program Indicators	\$254,400	32%	\$0	\$X	\$254,400 - \$X
2. Market Effects Incentives	\$23,850	3%	total amount earned across all three years		
3. Activity Milestones Incentives	\$159,000	20%	\$100,000	\$59,000	\$0
Maximum Possible Performance Award (Cap)	\$795,000	100%			

Source: Final EEU Contract (2000-2002), Appendix C, online at <http://www.state.vt.us/psb/eeucontract.html>

Regulatory Proceedings Establishing The Efficiency Resource

The regulatory requirement that a utility or other licensed provider of electricity or gas service invest in all cost-effective energy efficiency can be established by rule, by rate case decision, by order in a Certificate of Need determination, in standard offer service resource decisions, or in the creation of funds to be spent to enhance public goods within the electricity system, such as System Benefit Charges (SBC) or Public Benefits Funds (PBF). In some states, the requirement may result from joint decisions of the legislature and the utility regulatory commission.

Regarding electricity, many states have Integrated Resource Planning (IRP) requirements which require demand as well as supply-side investment. Others, such as California and Montana, that have moved towards greater competition, require that the provider of electrical service to regulated customers (standard offer or default service) acquire a long-run portfolio of integrated resources, and that the distribution utility (whether or not the provider of energy services) also file an integrated resource plan.

Long Term Procurement Planning

Arizona

Arizona utilities are not required to submit IRPs, but a 2005 settlement with Arizona Public Service Corporation (APS) requires the utility to examine its procurement policies and to compare supply- and demand- side investments on an equal basis:

The Commission's Staff will schedule workshops on resource planning, focusing on developing needed infrastructure and a flexible, timely, and fair competitive procurement process.⁵⁸

Pursuant to the Settlement Agreement, APS is to invite DSM resources to participate in its [power procurement] RFP and other competitive solicitations⁵⁹, and must evaluate them in a consistent and comparable manner.⁶⁰

. . . IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall schedule workshops on resource planning issues and distributed generation issues within 90 days of the effective date of this Decision.⁶¹

⁵⁸ ACC Docket E-01345A-03-0437, Order of April 7, 2005, p. 26. See <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>

⁵⁹ This solicitation is more fully described later in this document. "The Settlement Agreement provides that APS will issue an RFP or other competitive solicitation(s) in 2005 seeking long-term resources of not less than 1000 MW for 2007 and beyond. "Long-term" resource is defined as acquisition of a generating facility or an interest in one, or any PPA of 5 years or longer." See p.25.

⁶⁰ ACC Docket E-01345A-03-0437, Order of April 7, 2005, p. 31. See <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>

⁶¹ *Ibid.*, p. 42.

California: Long-Term Procurement Planning (LTPP) process

In 2002, the California Legislature approved AB 57, which mandated a return to an IRP process after a hiatus during restructuring. In January 2004, the CPUC adopted the regulatory framework for the LTPP process in Decision 0401050:

Findings of Fact:

10. There is a broad range of resource applications and technologies that California can rely on to meet its reserve levels. . . .

11. The Energy Action Plan, as well as the guidance given for this proceeding, established a "loading order" for new resource additions emphasizing increased energy efficiency, demand response/dynamic pricing, and renewable energy. . .

25. The utilities should prioritize resource additions consistent with our direction in D.02-10-062 and the loading order of resources stated in the Energy Action Plan. . .

67. In guiding the utilities' long term planning process, we focus on developing an integrated resource approach, one that recognizes our policy priority for demand-side resource additions, and that optimizes generation and transmission resources.⁶²

Portfolio Management and Default Supply Procurement

The following restructured states now require either inclusion of DSM in default supply procurement, or the use of a "portfolio management" approach to default supply.

Maine

2006 legislation allows energy efficiency to be used in standard offer procurement⁶³, allows long-term contracting, and establishes a "loading order", with priority given to energy efficiency and demand response resources.

Demand response and energy efficiency. The commission may incorporate cost-effective demand response and energy efficiency into the supply of standard-offer service. The commission shall encourage entities based in this State that are not otherwise either a standard-offer service provider or its affiliate to participate in supplying cost-effective demand response or energy efficiency pursuant to this subsection.

Authority to establish various contract lengths and terms. For the purpose of providing over a reasonable time period the lowest price for standard-offer service to residential and small commercial customers, the commission, with respect to residential and small commercial standard-offer service, may, in addition to incorporating cost-effective demand response and energy efficiency pursuant to

⁶² California Public Utilities Commission Decision 0401050, Section X. See http://www.cpuc.ca.gov/Published/Final_decision/33625-09.htm#P1079_316447

⁶³ The Maine Public Utilities Commission is responsible for procurement of standard offer service.

subsection 4-B and to the extent authorized in section 3210-C, incorporating the energy portion of any contracts entered into pursuant to section 3210-C, establish various standard-offer service contract lengths and terms.

. . . **Commission authority.** The commission may direct large investor-owned transmission and distribution utilities to enter into long-term contracts for:

A. Capacity resources;

B. Any available energy associated with capacity resources contracted under paragraph A . . .

. . . In selecting capacity resources for contracting pursuant to subsection 3, the commission shall apply the following standards.

A. The commission shall select capacity resources that are competitive and the lowest price when compared to other available offers for capacity resources of the same or similar contract duration. The commission shall consider the cost of the capacity and the cost of related energy. The commission shall, by rules adopted pursuant to subsection 10, establish a methodology for calculating and considering the cost of related energy for capacity-only offers.

B. Among capacity resources meeting the standard in paragraph A, the commission shall choose among capacity resources in the following order of priority:

- (1) New interruptible, demand response or energy efficiency capacity resources located in this State;
- (2) New renewable capacity resources located in this State;
- (3) New capacity resources with no net emission of greenhouse gases . . .⁶⁴

Delaware

2006 legislation requires utilities to conduct integrated resource planning for default service:

(a)(4) On or after May 1, 2006, it is the policy of the State that Electric Distribution Companies subject to the oversight of the Commission and as part of their obligation to be Standard Offer Service Suppliers shall engage in Integrated Resource Planning for the purpose of evaluating and diversifying their electric supply options, efficiently and at the lowest cost to their customers.

. . . (a) All Electric Distribution Companies subject to the jurisdiction of the Commission shall be the Standard Offer Service Supplier and Returning Customer Service Supplier in their distribution service territories. Customers on Returning Customer Service may return to Standard Offer Service after receiving Returning Customer Service for a minimum of 12 consecutive months.

(b) Subject to the approval of the Commission, the Standard Offer Service Provider to meet its electric supply requirements shall have the ability to:

- (1) enter into short- and long-term contracts for the procurement of power necessary to serve its customers;
- (2) own and operate facilities for the generation of electric power;

⁶⁴ LD 2041 of the 2006 Legislature. See <http://janus.state.me.us/legis/LawMakerWeb/externalsiteframe.asp?ID=280020488&LD=2041&Type=1&SessionID=6>

- (3) build generation and transmission facilities (subject to any other requirements in any other section of the Delaware Code regarding siting, etc.)
- (4) make investments in Demand-Side resources, and
- (5) take any other Commission-approved action to diversify their retail load.

In order to take such action, DP&L as a Standard Offer Service Supplier must file an application with the Commission or have had such action approved as part of its Integrated Resource Plan pursuant to subsection (c). If DP&L as a Standard Offer Service Supplier files an application under this subsection, then the Commission shall hold an evidentiary hearing on DP&L's request and shall approve the request if the Commission finds that such action is in the public interest. If the Commission approves such a request, the Commission shall review all reasonable incurred costs of the contracts, facilities or programs in accordance with Chapter 1, Subchapter 3 of this Title. Costs from these projects which have been approved by the Commission shall be included in Standard Offer Service rates.

(c)(1) DP&L is required to conduct Integrated Resource Planning. On December 1, 2006, and on the anniversary date of the first filing date of every other year thereafter (i.e., 2008, 2010 et seq.), DP&L shall file with the Commission, the Controller General, the Director of the Office of Management and Budget and the Energy Office an Integrated Resource Plan ("IRP"). In its IRP, DP&L shall systematically evaluate all available supply options during a ten (10)-year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost. The IRP shall set forth DP&L's supply and demand forecast for the next ten (10)-year period, and shall set forth the resource mix with which DP&L proposes to meet its supply obligations for that ten-year period (i.e., Demand-Side Management Programs, long-term purchased power contracts, short-term purchased power contracts, self generation, procurement through wholesale market by RFP, spot market purchases, etc.).

1. As part of its IRP process, DP&L shall not rely exclusively on any particular resource or purchase procurement process. In its IRP, DP&L shall explore in detail all reasonable short- and long-term procurement or Demand-Side Management strategies, even if a particular strategy is ultimately not recommended by the Company. At least 30 percent of the resource mix of DP&L shall be purchases made through the regional wholesale market via a bid procurement or auction process held by DP&L. Such process shall be overseen by the Commission subject to the procurement process approved in PSC Docket #04-391 as may be modified by future Commission action.

2. In developing the IRP, DP&L may consider the economic and environmental value of:

- (i) resources that utilize new or innovative baseload technologies (such as coal gasification);
- (ii) resources that provide short- or long-term environmental benefits to the citizens of this State (such as renewable resources like wind and solar power);
- (iii) facilities that have existing fuel and transmission infrastructure;
- (iv) facilities that utilize existing brownfield or industrial sites;
- (v) resources that promote fuel diversity;

- (vi) resources or facilities that support or improve reliability; or
- (vii) resources that encourage price stability.

The IRP must investigate all potential opportunities for a more diverse supply at the lowest reasonable cost.

Maryland

2006 legislation authorizes energy efficiency procurement for standard offer service:

By regulation or order . . . the Commission shall require or allow the procurement of cost-effective energy efficiency and conservation measures and services with projected and verifiable energy savings to offset anticipated demand to be served by standard offer service, and the imposition of other cost-effective demand-side management programs.⁶⁵

Montana

Montana's two major utilities are regulated differently. While one utility is regulated traditionally and is required to do Integrated Resource Planning, the other utility restructured and is required to conduct Portfolio Management Planning for default supply. The Montana statute on Portfolio Management states:

(1) The default supplier shall:

- (a) plan for future default supply resource needs;
- (b) manage a portfolio of default supply resources; and
- (c) procure new default supply resources when needed.

(2) The default supplier shall pursue the following objectives in fulfilling its duties pursuant to subsection (1):

(a) provide adequate and reliable default supply services at the lowest long-term total cost;

(b) conduct an efficient default supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options;

(c) identify and cost-effectively manage and mitigate risks related to its obligation to provide default electricity supply service;

(d) use open, fair, and competitive procurement processes whenever possible; and

(e) provide default supply services at just and reasonable rates.⁶⁶

Montana's administrative rules further refine the process:

OBJECTIVES (1) In order to satisfy its default supply responsibilities, a DSU should pursue the following objectives in assembling and managing an electricity supply portfolio. The DSU should:

(a) provide default supply customers adequate and reliable default supply services, stably and reasonably priced, at the lowest long-term total cost;

⁶⁵ SB 1 of the 2006 Legislative Session. See <http://mlis.state.md.us/2006s1/billfile/SB0001.htm>

⁶⁶ Montana Code Annotated 69-8-419. See <http://data.opi.state.mt.us/bills/mca/69/8/69-8-419.htm>

- (b) design rates for default supply service that are equitable and promote rational, economically efficient consumption and customer choice decisions;
- (c) assemble and maintain a balanced, environmentally responsible portfolio of power supply and demand-side management resources coordinated with economically efficient cost allocation and rate design that most efficiently supplies firm, full electricity supply service to default supply customers over the planning horizon;
- (d) maintain an optimal mix of demand-side management and power supply sources with respect to underlying fuels, generation technologies and associated environmental impacts, and a diverse mix of long, medium and short duration power supply contracts with staggered start and expiration dates.⁶⁷

RESOURCE ACQUISITION (1) A DSU should apply industry accepted procurement practices to acquire default supply resources. The commission cannot prescribe in advance the precise industry accepted practices a DSU must apply since industry accepted practices vary depending on context and circumstances. Generally, an industry accepted approach to resource procurement should encompass the following basic steps:

- (a) obtain and consider upfront input and recommendations from an advisory committee throughout planning and procurement processes, as described in ARM [38.5.8225](#);
- (b) explore a wide variety of alternative supply and demand-side resources, products and prices;
- (c) collect proposals from various parties offering supply and demand-side resources and products;
- (d) analyze the proposals or offers with respect to price and non-price factors in the context of the goals and objectives of these guidelines;
- (e) select the most appropriate proposals and develop a shortlist;
- (f) negotiate the most appropriate contract; and
- (g) anticipate changing circumstances and remain flexible.⁶⁸

DEMAND-SIDE RESOURCES (1) Energy efficiency and conservation measures can effectively contribute to serving total default electricity load requirements at the lowest long-term total cost. A DSU should develop a comprehensive inventory of all potentially cost-effective demand-side resources available in its service area and optimize the acquisition of demand-side resources over its planning horizon.

(2) A DSU should evaluate the cost-effectiveness of demand-side resources and programs based on its long-term avoidable costs. Cost-effectiveness evaluations of demand-side resources should encompass avoidable electricity supply, transmission and distribution costs.

(3) A non-participant (no-losers) test considers utility-sponsored demand-side management programs cost effective only if rates to customers that do not participate in the program are not affected by the program. A DSU should not evaluate the cost-effectiveness of demand-side resources using a non-participant test.

(4) A DSU should develop and strive to achieve targets for steady, sustainable investments in cost-effective, long-term demand-side resources. A DSU's investment in

⁶⁷ Montana Administrative Code 38.5.8204, online at <http://161.7.8.61/38/38-6154.htm>

⁶⁸ MAC 38.5.8212, online at <http://161.7.8.61/38/38-6168.htm>

demand-side resources should be coordinated with and complement its universal system benefits activities.

(5) Except when the entire resource would otherwise be lost, a DSU's demand-side management programs should not be focused on "cream skimming;" the least expensive and most readily obtainable resource potential should be acquired in conjunction with other measures that are cost-effective only if acquired in a package with the least expensive, most readily available resources.⁶⁹

Rhode Island

Legislation enacted in 2006⁷⁰ extended standard offer service from 2009 to 2020 and mandated least-cost planning for standard offer procurement, among other requirements:

There is created a permanent joint committee of the general assembly on energy to consist of eight (8) members of the general assembly. . . to promote and encourage the development of effective and efficient plans, programs, strategies, and standards for energy conservation, energy efficiency, and energy resource procurement, use and development, including renewable energy, and in the furtherance to this purpose, it shall be the duty of the joint committee to provide oversight of the implementation of standard offer service through 2020 and all agencies and instrumentalities of the state with responsibility for energy programs, including, but not limited to, the office of energy resources, the Rhode Island energy efficiency and resources management council, the public utilities commission, and the division of public utilities.⁷¹

. . . (e) The legislature further finds and declares as of 2006:

- (1) That prices of energy, including especially fossil-fuels and electricity, are rising faster than the cost of living and are subject to sharp fluctuations, which conditions create hardships for **many households, institutions, organizations, and businesses in the state;**
- (2) That while utility restructuring has brought some benefits, notably in transmission and distribution costs and more efficient use of generating capacities, it has not resulted in **competitive markets for residential and small commercial industrial customers, lower overall prices, or greater diversification of energy resources used for electrical generation;**
- (3) That the state's economy and the health and general welfare of the people of Rhode Island benefit when energy supplies are reliable and least-cost; and
- (4) That it is a necessary move beyond basic utility restructuring in order to secure for Rhode Island, to the maximum extent reasonably feasible, the benefits of reasonable and stable rates, least-cost procurement, and system reliability that includes energy resource diversification, **distributed generation, and load management.**⁷²

. . . Through year 2009, and effective July 1, 2007, through year 2020, each electric distribution company shall arrange for a standard power supply offer ("standard offer") to customers that have not elected to enter into power supply arrangements with other

⁶⁹ MAC 38.5.8218. See <http://161.7.8.61/38/38-6175.htm>

⁷⁰ Bill text of H8205 is available online at <http://www.rilin.state.ri.us/Billtext/BillText06/HouseText06/H8025Aaa.pdf>.

⁷¹ Rhode Island General Laws, 22-7.10-1

⁷² Rhode Island General Laws, 39-1-1

nonregulated power suppliers. The rates that are charged by the electric distribution company to customers for standard offer service shall be approved by the commission and shall be designed to recover the electric distribution company's costs and no more than the electric distribution company's costs; provided, that the commission may establish and/or implement a rate that averages the costs over periods of time. The electric distribution company shall not be entitled to recover any profit margin on the sale of standard offer power, except with approval of the commission as may be necessary to implement fairly and effectively, system reliability and least-cost procurement.⁷³

. . . Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in section 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.

(a) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement, which shall include standards and guidelines for:

(1) System reliability procurement, including but not limited to:

(i) Procurement of energy supply from diverse sources, including, but not limited to, [renewable energy resources as defined in chapter 39-26](#);

(ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits;

(iii) Demand response, including, but not limited to, distributed generation, back-up generation and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;

(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) for qualifying distributed generation, demand response, and renewable energy resources, (B) for net-metering, (C) for back-up power and/or standby rates that reasonably facilitate the development of distributed generation, and (D) for such other matters as the [commission may find necessary or appropriate](#).

(2) Least-cost procurement, which shall include procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply, including supply for periods of high demand.

(b) The standards and guidelines provided for by subsection (a) shall be subject to periodic review and as appropriate amendment by the commission, which review will conduct not less frequently than every three (3) years after the adoption of the standards and guidelines.

(c) To implement the provisions of this section:

⁷³ Rhode Island General Laws, 39-1-27.3(b)

(1) The commissioner of the office of energy resources and the energy efficiency and resources management council, either or jointly or separately, shall provide the commission findings and recommendations with regard to system reliability and energy efficiency and conservation procurement on or before March 1, 2008, and triennially on or before March 1, thereafter through March 1, 2017.

(2) The commission shall issue standards not later than June 1, 2008, with regard to plans for system reliability and energy efficiency and conservation procurement, which standards may be amended or revised by the commission as necessary and/or appropriate.

(3) The energy efficiency and resources management council shall prepare by July 15, 2009, a reliability and efficiency procurement opportunity report which shall identify opportunities to procure efficiency, distributed generation, demand response and renewables, which report shall be submitted to the electrical distribution company, the commission, the office of energy resources and the joint committee on energy.

(4) Each electrical distribution company shall submit to the commission on or before September 1, 2008, and triennially on or before September 1, thereafter through September 1, 2017, a plan for system reliability and energy efficiency and conservation procurement. In developing the plan, the distribution company may seek the advice of the commissioner and the council. The plan shall include measurable goals and target percentages for each energy resource, pursuant to standards established by the commission, including efficiency, distributed generation, demand response, combined heat and power, and renewables.⁷⁴

. . . Each electric distribution company shall submit a proposed supply procurement plan or plans to the commission not later than March 1, 2009, and each March 1, thereafter through March 1, 2018. The supply procurement plan or plans shall be consistent with the purposes of least-cost procurement and shall, as appropriate, take into account plans and orders with regard to system reliability and energy efficiency and conservation procurement. The supply procurement plan or plans will include the acquisition procedure, the pricing options being sought, and a proposed term of service for which standard offer service will be acquired . . . All the components of the 6 procurement plans, shall be subject to commission review and approval. Once a procurement plan is approved by the commission, the electric distribution company shall be authorized to acquire standard offer service supply consistent with the approved procurement plan and recover its costs incurred from providing standard offer service pursuant to the approved procurement plan.⁷⁵

Least-cost or Integrated Resource Planning

Connecticut (gas only)

Connecticut's 2005 Energy Independence Act requires the state's gas utilities to submit biennial reports and annual gas conservation plans.

(a) On or before October first of each even-numbered year, a gas company, as defined in section 16-1, as amended by this act, shall furnish a report to the Department of Public

⁷⁴ Rhode Island General Laws, 39-1-27.7

⁷⁵ Rhode Island General Laws, 39-1-27.8

Utility Control containing a five-year forecast of loads and resources. The report shall describe the facilities and supply sources that, in the judgment of such gas company, will be required to meet gas demands during the forecast period. The report shall be made available to the public and shall be furnished to the chief executive officer of each municipality in the service area of such gas company, the regional planning agency which encompasses each such municipality, the Attorney General, the president pro tempore of the Senate, the speaker of the House of Representatives, the joint standing committee of the General Assembly having cognizance of matters relating to public utilities, any other member of the General Assembly making a request to the department for the report and such other state and municipal entities as the department may designate by regulation. The report shall include: (1) A tabulation of estimated peak loads and resources for each year; (2) data on gas use and peak loads for the five preceding calendar years; (3) a list of present and projected gas supply sources; (4) specific measures to control load growth and promote conservation; and (5) such other information as the department may require by regulation. A full description of the methodology used to arrive at the forecast of loads and resources shall also be furnished to the department. The department shall hold a public hearing on such reports upon the request of any person. On or before August first of each odd-numbered year, the department may request a gas company to furnish to the department an updated report. A gas company shall furnish any such updated report not later than sixty days following the request of the department.

(b) Not later than October 1, 2005, and annually thereafter, a gas company, as defined in section 16-1, as amended by this act, shall submit to the Department of Public Utility Control a gas conservation plan, in accordance with the provisions of this section, to implement cost-effective energy conservation programs and market transformation initiatives. All supply and conservation and load management options shall be evaluated and selected within an integrated supply and demand planning framework. The department shall, in an uncontested proceeding during which the department may hold a public hearing, approve, modify or reject the plan.

(c) (1) The Energy Conservation Management Board, established pursuant to section 16-245m, as amended by this act, shall advise and assist each such gas company in the development and implementation of the plan submitted under subsection (b) of this section. Each program contained in the plan shall be reviewed by each such gas company and shall be either accepted, modified or rejected by the Energy Conservation Management Board before submission of the plan to the department for approval. The Energy Conservation Management Board shall, as part of its review, examine opportunities to offer joint programs providing similar efficiency measures that save more than one fuel resource or to otherwise coordinate programs targeted at saving more than one fuel resource. Any costs for joint programs shall be allocated equitably among the conservation programs.

(2) Programs included in the plan shall be screened through cost-effectiveness testing that compares the value and payback period of program benefits to program costs to ensure that the programs are designed to obtain gas savings whose value is greater than the costs of the program. Program cost-effectiveness shall be reviewed annually by the department, or otherwise as is practicable. If the department determines that a program

fails the cost-effectiveness test as part of the review process, the program shall either be modified to meet the test or shall be terminated. On or before January 1, 2007, and annually thereafter, the board shall provide a report, in accordance with the provisions of section 11-4a, to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment, that documents expenditures and funding for such programs and evaluates the cost-effectiveness of such programs conducted in the preceding year, including any increased cost-effectiveness owing to offering programs that save more than one fuel resource.⁷⁶

Hawaii

Hawaii's IRP Framework was adopted in 1992 and states:

Integrated Resource Plans shall be developed upon consideration and analyses of the costs, effectiveness, and benefits of all appropriate, available, and feasible supply-side and demand-side options. . . The utility is entitled to recover all appropriate and reasonable IRP and implementation costs. In addition, existing disincentives should be removed and, as appropriate, incentives should be established to encourage and reward aggressive utility pursuit of demand-side management programs. Incentive mechanisms should be structured to that investment in suitable and effective demand-side management programs are at least as attractive to the utility as investment in supply-side options.⁷⁷

Indiana

A utility operating or owning, in part or whole, an electrical generating facility as of January 1, 1995, to provide electric service within the state of Indiana must submit to the commission on a biennial basis, beginning on or before November 1, 1995, an integrated resource plan consistent with this rule. . . .⁷⁸ For each year of the planning period, excluding subsection 6(a)(6) [*subdivision (6)*], recognizing the potential effects of self-generation, an electric utility shall provide a description of the utility's electric power resources that must include . . . A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy. . . .An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements.

⁷⁶ Connecticut Energy Independence Act, Section 22. See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

⁷⁷ "A Framework for Integrated Resource Planning", Hawaii Public Utilities Commission Decision and Order 11630, May 1992. p.4. See http://www.heco.com/images/pdf/HECO_IRP2_App_A.pdf

⁷⁸ Indiana Administrative Code, 170.4.7 Sec 3 (c). See <http://www.in.gov/legislative/iac/title170.html>

The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers.⁷⁹

Minnesota

A utility shall file a resource plan with the commission periodically in accordance with rules adopted by the commission. . . . As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.⁸⁰

Minnesota's rules define resource plans as follows:

'Resource plan' means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, modifying, and constructing utility plant and equipment; buying power generated by other entities; controlling customer loads; and implementing customer energy conservation.⁸¹

Missouri

The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. This objective requires that the utility shall . . . consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process.⁸²

Montana

Montana's integrated resource planning process applies to the state's one vertically integrated utility. (The other utility, which is restructured, is required to conduct portfolio management for default supply. See "Portfolio Management and Default Supply Procurement" section for more information.)

(1) "Integrated least cost resource planning" is an ongoing, dynamic and flexible process which:

(a) explicitly manages the consequences of uncertainty and risk associated with a utility's market characteristics and supply alternatives,

⁷⁹ Indiana Administrative Code, 170.4.7.6. See <http://www.in.gov/legislative/iac/title170.html>

⁸⁰ Minnesota Statutes 2005, 216B.2422. See <http://www.revisor.leg.state.mn.us/stats/216B/2422.html>.

⁸¹ Minnesota Rules, 7843.0100, Subp. 9. See

http://www.revisor.leg.state.mn.us/bin/getpub.php?pubtype=RULE_CHAP&year=current&chapter=7843

⁸² Missouri Code of State Regulations, 4 CSR 240-22. See <http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf>

(b) integrates the demand- and supply-side resources that represent the least cost to society over the long-term,

(c) explicitly weighs a broad range of resource attributes (e.g., environmental externalities) in the evaluation of alternative resources . . .⁸³

Nevada

Nevada utilities are required by statute to submit triennial resource plans:

1. A utility which supplies electricity in this state shall . . . submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the Commission.
2. The Commission shall, by regulation, prescribe the contents of such a plan including, but not limited to, the methods or formulas which are used by the utility to:
 - (a) Forecast the future demands; and
 - (b) Determine the best combination of sources of supply to meet the demands or the best method to reduce them.⁸⁴

By regulation, resource plans in Nevada must include demand side plans:

1. As part of its resource plan, a utility shall submit a demand side plan.
2. The demand side plan must include:
 - (a) An identification of end-uses for programs for conservation and demand management.
 - (b) An assessment of savings attributable to technically feasible programs for conservation and demand management, as determined by the utility. The programs must be ranked in a list according to the level of savings in energy or reduction in demand, or both.
 - (c) An assessment of technically feasible programs to determine which will produce benefits in peak demand or energy consumption. The utility shall estimate the cost of each such program. The methods used for the assessment must be stated in detail, specifically listing the data and assumptions considered in the assessment.
3. In creating its demand side plan, a utility shall consider the impact of applicable new technologies on current and future demand side options. The consideration of new technologies must include, without limitation, consideration of the potential impact of advances in digital technology and computer information systems.
4. The demand side plan must provide a list of the programs for which the utility is requesting the approval of the Commission. The list must include:
 - (a) An estimate of the reduction in the peak demand and energy consumption that would result from each proposed program, in kilowatt-hours and kilowatts saved. The programs must be listed according to their expected savings and their contribution to a reduction in peak demand and energy consumption based upon realistic estimates of the penetration of the market and the average life of the programs.

⁸³ Montana Administrative Code 38.5.2002. See <http://arm.sos.state.mt.us/38/38-698.htm>

⁸⁴ Nevada Revised Statutes 704.741. See <http://www.leg.state.nv.us/NRS/NRS-704.html#NRS704Sec741>

(b) An assessment of the costs of each proposed program and the savings produced by the program. If the program can be relied upon to reduce peak demand on a firm basis, the assessment must include the savings in the costs of transmission and distribution.

(c) An assessment of the impact on the utility's load shapes of each proposed and existing program for conservation and demand management.

(d) If a program is an educational program, the projected expenses of the utility for the educational program.

5. The utility shall include with its demand side plan a report on the status of all programs for conservation and demand management that have been approved by the Commission. The report must include tables for each such program showing, for each year, the planned and achieved reduction in kilowatt-hours, the reduction in kilowatts and the cost of the program.

6. On or before August 15 of each year following the filing of its resource plan, the utility shall file with the Commission a copy of the complete analysis the utility used in determining for the upcoming year which conservation and demand management programs are to be continued and which programs are to be cancelled. The Commission will process this analysis in the same manner as an amendment filed pursuant to [NAC 704.9503](#).⁸⁵

New Mexico

I. public utility resource planning to meet New Mexico's energy service needs should be identified and evaluated on an ongoing basis in accordance with the principles of integrated resource planning;⁸⁶

Pursuant to the commission's rulemaking authority, public utilities supplying electric or natural gas service to customers shall periodically file an integrated resource plan with the commission. Utility integrated resource plans shall evaluate renewable energy, energy efficiency, load management, distributed generation and conventional supply-side resources on a consistent and comparable basis and take into consideration risk and uncertainty of fuel supply, price volatility and costs of anticipated environmental regulations in order to identify the most cost-effective portfolio of resources to supply the energy needs of customers. The preparation of resource plans shall incorporate a public advisory process. Nothing in this section shall prohibit public utilities from implementing cost-effective energy efficiency and load management programs and the commission from approving public utility expenditures on energy efficiency programs and load management programs prior to the commission establishing rules and guidelines for integrated resource planning. The commission may exempt public utilities with fewer than five thousand customers and distribution-only public utilities from the requirements of this section. The commission shall take into account a public utility's resource planning requirements in other states and shall authorize utilities that operate in multiple states to implement plans that coordinate the applicable state resource planning

⁸⁵ Nevada Administrative Code 704.934. See <http://www.leg.state.nv.us/NAC/NAC-704.html#NAC704Sec9523>

⁸⁶ New Mexico Statutes, Chapter 62-17-2. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

requirements. The requirements of this section shall take effect one year following the commission's adoption of rules implementing the provisions of this section.⁸⁷

Vermont

Vermont's Least Cost Planning statute requires Vermont utilities to procure all cost-effective energy efficiency:

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

(a)(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. Proposed plans shall be submitted to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section.⁸⁸

Washington

Washington's Administrative Code states:

"Integrated resource plan" or "plan" means a plan describing the mix of generating resources and improvements in the efficient use of electricity that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers. . . .

"Lowest reasonable cost" means the lowest cost resulting from an exhaustive and detailed analysis of all alternative sources and mixes of supply, considerations of market-volatility risks of generating and demand-side resources, and of system reliability and operational risks. . . .

At a minimum, integrated resource plans must include:

⁸⁷ New Mexico Statutes, Chapter 62-17-10. See

<http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

⁸⁸ 30 VSA 218C. See <http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c>

(a) A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses.

(b) An assessment of technically feasible improvements in the efficient use of electricity, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the efficiency improvements.

(c) An assessment of technically feasible generating technologies. .

(d) A comparative evaluation of generating resources and improvements in the efficient use of electricity based on a consistent method for calculating cost-effectiveness.⁸⁹

Efficiency Planning

Efficiency plans are required in some states and may be done in the absence of, or in addition to, an IRP-type process.

California

In September 2004, the CPUC issued Decision 0409060, establishing explicit MWh savings goals for each of California's main IOUs and requiring that these goals be explicit in the IOUs' efficiency plans and resource plans:

The Energy Action Plan, adopted by this Commission, the California Energy Commission (CEC) and the California Consumer Power and Conservation Financing Authority (CPA), identifies reduction of energy use per capita as one of six sets of actions that are of critical importance. . . By today's decision, we have translated this mandate into explicit, numerical goals for electricity and natural gas savings for the four largest investor-owned utilities (IOUs): Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE) and Southern California Gas Company (SoCalGas). Electric and natural gas savings from energy efficiency programs funded by ratepayers through the public goods charge (PGC) and procurement rates will contribute to these goals, including those achieved through the low-income energy efficiency (LIEE) program.⁹⁰

Findings of Fact:

1. Numerical targets for electricity and natural gas savings should be established in the context of California's overriding goal to pursue all cost-effective energy efficiency opportunities.

⁸⁹ Washington Administrative Code 480-100-238. See <http://www.wutc.wa.gov/rms2.nsf/208e3d50fad2b39d88256a77006f9105/e091202136c29a8b88256feb0061419c!OpenDocument>

⁹⁰ California Public Utilities Commission Decision 0409060. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212.htm#P95_2834

2. The annual and cumulative numerical goals for energy savings must be aggressive and stretch the capabilities and efforts of all those involved in program planning and implementation. At the same time, these stretch goals need to reflect a pace for increasing program efforts that is achievable.

3. Today's adopted electricity and natural gas goals reflect the need to substantially increase efforts to procure energy efficiency over both the short- and long-term, based on recent assessments of its economic potential.

4. Today's adopted goals take into consideration the practical limits to effectively increasing program funding and ramping up programs to capture the full economic potential of energy efficiency in the near-term.

Conclusions of Law

1. The annual and cumulative savings goals presented in Tables 1A-1E are reasonable and should be adopted, subject to the updating process described in this decision.

IT IS ORDERED that:

3. Today's adopted savings goals will apply to the PY2006-PY2008 program cycle without further updates. These goals shall be updated every three years for use in subsequent program cycles. In preparation for the PY2009-PY2011 program cycle, Energy Division and California Energy Commission staff ("Joint Staff") shall jointly prepare recommendations for adjustments to today's adopted savings goals as appropriate, based on updated savings potential studies, accomplishment data, changes to mandatory efficiency standards and other evaluation studies and factors that staff deems appropriate. These studies shall continue to be funded out of public goods charge collections. The administration of savings potential and other evaluation studies, i.e., who contracts for and manages them, shall be addressed in a separate decision on energy efficiency administrative structure in this proceeding.

4. In submitting proposed energy efficiency program plans and funding levels to meet the savings goals adopted by the Commission, the program administrator(s) shall:

- a. Demonstrate that their proposed level of electric and natural gas energy efficiency program activities and funding is consistent with the Commission's -adopted electric and natural gas savings goals.,
- b. If there are differences between the near-term numerical goals and the savings levels associated with the program portfolios proposed for PY2006-PY2008, specifically describe how the numerical goals in later years will still be met by ramping up program efforts over time, by initiating innovative programs to improve program-effectiveness ratios, or by other means.

6. The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term. To this end, our upcoming decisions in R. 04-04-003 concerning the long-term procurement plans and 2005/2006 ongoing procurement authorizations of PG&E, SCE and SDG&E shall be made in full recognition

of the aggressive energy savings goals we adopt today. For the procurement plans that will be filed in 2006 and during subsequent procurement plan cycles, or for any updating to the long-term procurement plans required by the Commission before then, PG&E, SDG&E and SCE shall incorporate the most recently-adopted energy savings goals into those filings.⁹¹

In January 2005, the CPUC in Decision 0501055 adopted an administrative structure for the administration of efficiency programs. In this proceeding, responsibility for administering efficiency was returned to the IOUs:

As discussed in today's decision, we choose the fork in the road that returns the IOUs to the lead role in Program Choice and Portfolio Management. In considering our options, we recognize that the energy crisis of 2000 and 2001 has changed the regulatory landscape in a profound way for California. As a result of California's painful experience with electric industry restructuring, the Legislature and this Commission have directed the IOUs to resume responsibility for procuring resources to meet customer demand. The energy crisis has also brought about a renewed and expanded appreciation for energy efficiency as a cost-effective resource to meet that demand. Accordingly, the Energy Action Plan has placed energy efficiency at the forefront of energy policy and resource procurement in California.

Decisions in California concerning the optimal levels of energy efficiency and supply-side resources will now be made in the resource planning process undertaken by the IOUs, subject to our oversight and approval. In this context, making another entity (or entities) responsible for Program Choice and Portfolio Management of energy efficiency means that all of the program selection and day-to-day management decisions would be "handed down" to the IOUs to incorporate into their resource plans and resource adequacy projections. As we stated in Decision (D.) 04-01-050, California IOUs should not be required to adopt the forecasts and resource plans of others because "[w]e strongly believe that the utilities themselves must be responsible and accountable for providing their customers reliable service and just and reasonable rates; this is the utilities' statutory obligation to serve." . . .

. . . .By D.04-09-060, we adopted electric and natural gas savings goals by IOU service territory through the year 2013, subject to updates for 2009 and beyond. Completing all the remaining tasks in time for the 2006 funding cycle will require an ambitious schedule during 2005. We call on all the stakeholders to put past differences aside and work collaboratively in the months ahead. Working together, all stakeholders will benefit from the result of these efforts: The full recognition of energy efficiency as a viable resource that can be relied upon to reduce the demand for energy in California.⁹²

⁹¹ Ibid. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/40212-07.htm#P285_94932

⁹² D. 0501055 available online at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43628.htm (footnotes omitted)

Iowa

Iowa utilities are not required to file IRPs. However, once every five years they must file energy efficiency plans, which contain some of the same elements as traditional IRPs. Iowa statute states:

Gas and electric utilities required to be rate-regulated under this chapter shall file energy efficiency plans with the board. An energy efficiency plan and budget shall include a range of programs, tailored to the needs of all customer classes, including residential, commercial, and industrial customers, for energy efficiency opportunities. The plans shall include programs for qualified low-income persons including a cooperative program with any community action agency within the utility's service area to implement countywide or communitywide energy efficiency programs for qualified low-income persons. Rate-regulated gas and electric utilities shall utilize Iowa agencies and Iowa contractors to the maximum extent cost-effective in their energy efficiency plans filed with the board.⁹³

From Iowa's administrative code:

Each gas or electric utility required by statute to be rate-regulated shall file an assessment of potential energy and capacity savings and an energy efficiency plan which shall include economically achievable programs designed to attain the performance standards developed by the board.⁹⁴

Establish The Measure Of Cost Effectiveness

Investing in cost-effective energy efficiency at the generation, transmission, or distribution level requires establishing criteria for determining the cost-effectiveness of demand-side resources. Standard criteria are used to compare the costs and benefits of efficiency investments. These cost-effectiveness tests measure several perspectives: for society as a whole (Total Resource Cost), for all customers collectively of the utility (Utility Cost), and the price impact on non-participant ratepayers (Rate Impact Measurement). The available reservoir of energy efficiency is significantly dependent on the cost-effectiveness tests used to decide what programs will be invested in. States with the most successful efficiency development have used TRC as the primary test, while taking into account the information provided by the other tests.

California

California uses the Total Resource Cost Test and the Program Administrator Test to evaluate efficiency program cost-effectiveness. Programs are evaluated on an individual basis, but also on a portfolio basis, to allow education-only and pilot programs to be included in an overall portfolio that meets the cost-effectiveness tests.

⁹³ Iowa Code 476.6(16). See <http://coolice.legis.state.ia.us/Cool-ICE/default.asp?category=billinfo&service=IowaCode>

⁹⁴ Iowa Administrative Code 199—35.3(476). See <http://www.legis.state.ia.us/Rules/Current/iac/199iac/19935/19935.pdf>

By D.94-10-059, the Commission established a program performance basis for pre-1998 resource programs that was based on a cost-effectiveness metric comprised of a weighted average of the Total Resource Cost (TRC) test and Utility Cost (UC) tests. Both tests produce a net present dollar value for "net resource benefits" (program benefits minus program costs), but from somewhat different perspectives. The TRC test looks at the net resource benefits of an energy efficiency measure, program or portfolio of programs from the perspective of whether or not energy efficiency is cost-effective as a resource option compared to the supply-side options it would defer or replace. Therefore, the test measures the net effect of energy efficiency based on the total costs of the program, including both the participating customer's and the utility's (or more generically, the program administrator's) costs. The TRC test attempts to quantify the changes in total resource costs for the utility and ratepayers within the relevant service territories. The costs for the TRC test are the equipment or measure costs, including installation, operation, maintenance and administration costs, no matter who pays for them. In addition, costs for this test include the increase in supply costs for the periods in which load is increased. The benefits are the avoided supply-side costs—the reduction in transmission, distribution, generation and capacity costs valued at marginal cost. In the Societal Test variant of the TRC test, the effects of certain externalities are included, such as the benefit of avoided environmental damages, and a societal discount rate is used to calculate net present value of costs and benefits. The TRC-Societal Test attempts to quantify the change in the total resource costs to society as a whole, rather than only to the service territory (the utility and its ratepayers). The UC test, which has subsequently been renamed the Program Administrator Cost (PAC) test, looks at cost-effectiveness from the perspective of the administrator of energy efficiency programs. The benefits are the same as the TRC test, but costs are defined differently to include the costs incurred by the program administrator, and not the participating customer. That is, this test does not include the participating customers' out-of-pocket expenses, but does include the financial incentives paid to the customer to install the measure, along with other program costs incurred by the administrator.⁹⁵

Findings of Fact:

. . . 14. Considering the results of both the TRC and PAC tests of cost-effectiveness ("dual test") when evaluating all resource program proposals ensures that program administrators and program implementers do not spend more on financial incentives or rebates to participating customers than is necessary to achieve TRC benefits. . .

. . . 23. Weighting the TRC test of cost-effectiveness by two-thirds and the PAC test by one-third in the calculation of performance basis is preferred to an equal weighting of these two tests. As discussed in this decision, putting more weight on the TRC results reflects our policy that the TRC should be the primary test of cost-effectiveness for ranking and funding resource programs. At the same time, including the PAC test in the performance basis appropriately acknowledges the dual-cost issue unique to energy efficiency investments. . .

⁹⁵ CPUC Decision 05-04-051, issued April 21, 2005. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783-03.htm#TopOfPage

... IT IS ORDERED THAT:

... Programs that are designed to defer or avoid more costly supply-side alternatives are referred to as "resource programs." These include programs that offer financial incentives (e.g., rebates) to customers to encourage them to install energy efficient measures or equipment. The performance basis for resource programs shall reflect the net resource benefits (energy savings minus costs) of the programs, utilizing a weighted average of the Total Resource Cost (TRC) and the Program Administrator's Cost (PAC) tests of cost-effectiveness. As discussed in this decision, the TRC net benefits shall be weighted two-thirds and the PAC net benefits shall be weighted one-thirds in that calculation. The value of the energy savings for both the TRC and the PAC tests shall be calculated using the avoided costs that are adopted in R.04-04-025, including the non-price components (e.g., environmental adders). The TRC and PAC net benefit calculations shall be conducted utilizing the IOUs' weighted cost of capital, as discussed in this decision. The savings and resource benefits counted towards the performance basis shall reflect installations in a given year, regardless of the year in which any given installation was funded. However, for the reasons discussed in this decision, savings resulting from commitments made prior to 2006 will not count towards the savings goals or in the calculation of performance basis for 2006 and beyond.⁹⁶

Connecticut

Connecticut's Energy Independence Act states that:

Programs included in the plan developed under subdivision (1) of subsection (d) of this section shall be screened through cost-effectiveness testing which compares the value and payback period of program benefits to program costs to ensure that programs are designed to obtain energy savings and system benefits, including mitigation of federally mandated congestion charges, whose value is greater than the costs of the programs. Cost-effectiveness testing shall utilize available information obtained from real-time monitoring systems to ensure accurate validation and verification of energy use. Program cost-effectiveness shall be reviewed annually, or otherwise as is practicable. If a program is determined to fail the cost-effectiveness test as part of the review process, it shall either be modified to meet the test or shall be terminated. On or before March 1, 2005, and [March 1, 2006] on or before March first annually thereafter, the board shall provide a report, in accordance with the provisions of section 11-4a, to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment [which] (A) that documents expenditures and fund balances and evaluates the cost-effectiveness of such programs conducted in the preceding year, and (B) that documents the extent to and manner in which the programs of such board collaborated and cooperated with programs, established under section 17 of this act, of municipal electric energy cooperatives.⁹⁷

Connecticut requires similar cost-effectiveness measures for gas conservation programs. See "Least-cost or Integrated Resource Planning" section for more information.

⁹⁶ Ibid. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783-07.htm#TopOfPage

⁹⁷ See (d)(3) in Section 5 of The Energy Independence Act (Public Act 05-1)
<http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

Iowa

Iowa Administrative Code states:

- (1) Cost-effectiveness tests. The utility shall analyze for cost-effectiveness proposed programs, using the societal, utility, ratepayer impact and participant tests. The utility's analyses shall use inputs or factors realistically expected to influence cost-effective implementation of programs, including the avoided costs filed pursuant to rules 35.9(476) and 35.10(476) or avoided costs determined by the utility's alternative method. If the utility uses a test other than the societal test as the criterion for determining the cost-effectiveness of utility implementation of energy efficiency programs and plans, the utility shall describe and justify its use of the alternative test or combination of tests and compare the resulting impacts with the impacts resulting from the societal test.
- (2) Cost-effectiveness threshold(s). The utility shall describe and justify the level or levels of cost-effectiveness, if greater or less than a benefit/cost ratio of 1.0, to be used as a threshold for cost-effective utility implementation of programs. The utility's threshold of cost-effectiveness for its plan as a whole shall be a benefit/cost ratio of 1.0 or greater.⁹⁸

Massachusetts

G.L. c. 25, § 19 requires the Department ensure that the programs funded by this mandatory charge are delivered in a cost-effective manner using competitive procurement processes to the fullest extent practicable.

Therefore, the Department concludes that the Total Resource Cost Test is the appropriate determination of program cost-effectiveness, for programs implemented by electric and gas companies and by municipal aggregators, pursuant to G.L. c. 164, § 134(b). As noted above, the Total Resource Test assesses program cost-effectiveness by valuing all of the direct economic benefits and costs of a particular program. Accordingly, that test includes as components all energy system benefits and costs; all participating customer benefits and costs including (a) savings in other resources such as oil, water and wastewater (sewerage) as appropriate; (b) such other benefits as increased productivity and reduced late payments; and (c) certain other "non-resource benefits" that do not arise directly out of electric or gas consumption but should be included because (1) reasonably foreseeable changes in regulation will increase industry cost structures and (2) such cost increases are avoidable by prudent actions today. The Department notes that several of the specific components we include in the Total Resource Cost Test capture the general benefits that the Joint Commenters include in their proposed Societal Test, in particular, a number of benefits and costs specific to low-income programs. Section IV, below, addresses the specific components that should be included in the Total Resource Test.⁹⁹

[D.2.c...] the Department reiterates our conclusion that the Total Resource Test is appropriate for determining the cost-effectiveness of energy efficiency programs.

⁹⁸ IAC 35.8(1)(e)

⁹⁹ DTE 98-100 Order re: cost-effectiveness. See <http://www.mass.gov/dte/electric/98-100/order.htm>

[Attachment I] 3.4 Discount Rate. Benefits and costs that are projected to occur over the term of each Energy Efficiency Program shall be stated in present value terms, using a discount rate that is equal to the yield on 30-year United States Treasury Bonds available at the close of trading on the first business day each year.

3.5 Cost-effectiveness. An Energy Efficiency Program shall be deemed cost-effective if its benefits are equal to or greater than its costs, as expressed in present value terms.¹⁰⁰

New Mexico

"cost-effective" means that the program being evaluated satisfies the total resource cost test...

“total resource cost test” means a standard that is met if, for an investment in energy efficiency or load management, on a life-cycle basis the avoided supply-side monetary costs are greater than the monetary costs of the demand-side programs borne by both the utility and the participants...¹⁰¹

Before the commission approves an energy efficiency and load management program for a public utility, it must find that the portfolio of programs is cost-effective and designed to provide every affected customer class with the opportunity to participate and benefit economically. The commission shall determine the cost-effectiveness of energy efficiency and load management measures using the total resource cost test.¹⁰²

Oregon

Order 05-920, dated August 2005, directs the Energy Trust of Oregon (the state’s efficiency programs administrator) to use the following cost-benefit tests:

The Commission expects the Trust to report the benefit/cost ratio for its conservation acquisition programs in its annual report based on the utility system perspective and societal perspective. The Commission expects the Trust to report significant mid-year changes in benefit/cost performance as necessary in its quarterly reports.¹⁰³

The Energy Trust’s cost-effectiveness screen uses three perspectives: utility, societal and consumer. The elements of these benefit/cost ratios are described in the Energy Trust’s cost-effectiveness policy paper

(see http://www.energytrust.org/Pages/about/library/policies/costeffectiveness_030414.pdf).

The Energy Trust uses a 3% real discount rate to bring costs and benefits to a present value in

¹⁰⁰ DTE 98-100 Final Order re: cost-effectiveness, Attachment I

<http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm>

¹⁰¹ New Mexico Statutes, Chapter 62-17-4. See

<http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

¹⁰² New Mexico Statutes, Chapter 62-17-5. See

<http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

¹⁰³ Order 05-920, Appendix A, page 11. See: <http://apps.puc.state.or.us/orders/2005ords/05-920.pdf>

its cost-benefit evaluations. The cost-benefit evaluation is not the only factor in Energy Trust investment decisions, but only programs and measures that pass the cost-effectiveness test qualify for Energy Trust funding.

The utility system perspective compares Energy Trust costs to the benefits to the utility system. The Energy Trust employs the utility system perspective prospectively, when deciding whether to proceed with programs and measures, and retrospectively to report end-of-year results and again when evaluations are completed.

The societal perspective (total resource cost) compares all benefits that can be quantified with reasonable effort to the combined cost to all parties in the efficiency investment. The societal perspective is employed prospectively. The Energy Trust uses any new information about societal costs in updated societal perspective calculations when it considers continuation of programs. The societal perspective includes a credit for carbon dioxide reduction.

Finally the Energy Trust applies the consumer perspective to check that the incentive options lead to a reasonable payback for the customer.¹⁰⁴

Establish The Appropriate Method To Compare Supply Costs To Demand Reduction Costs

Cost comparisons need to take into account the way in which a supply or demand side resource changes a utility's load curve (hourly demand), as each hour has its own costs. Averaging costs across many hours often will fail to reveal the true value of a demand-side resource. (The same can happen with renewable and customer-owned resources. A section specific to these resources may be added to this toolkit at a later date.)

Impact on Load Curve

Avoided Cost Methodologies

California

In April 2004, the CPUC opened docket R.0404025 to develop consistent methodologies for determining avoided costs. In Decision 0504024, issued in April 2005, the IOUs were directed to adopt avoided cost methodology¹⁰⁵ developed by E3, an independent contractor:

IT IS ORDERED that:

1. We adopt the *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted on

¹⁰⁴ Ibid, page 5.

¹⁰⁵ Complete methodology is available in the E3 document at http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.doc.

October 25, 2004, updated as discussed herein, for purposes of evaluating energy efficiency programs in Rulemaking 01-08-028 and related energy efficiency proceedings.

2. Until further order by the Commission, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), and San Diego Gas and Electric Company (SDG&E) shall each undertake its Energy Efficiency program evaluation for program year 2006 and beyond using avoided cost forecasts in conformance with the adopted methodology.¹⁰⁶

Iowa

Avoided capacity costs shall be based on the future supply option with the highest value for each year in the 20-year planning horizon identified in subrule 35.9(6). Avoided energy costs shall be based on the marginal costs of the utility's generating units or purchases. The utility shall use the same costing periods identified in 35.9(6) "b" when calculating avoided capacity and energy costs. A party may submit, and the board shall consider, alternative avoided capacity and energy costs derived by an alternative method. A party submitting alternative avoided costs shall also submit an explanation of the alternative method.

a. Avoided capacity costs. Calculations of avoided capacity costs in each costing period shall be based on the following formula:

AVOIDED CAPACITY COST = C x (1 + RM) x (1 + DLF) x (1 + EF) C (capacity) is the greater of NC or RC.

NC (new capacity) is the value of future capacity purchase costs or future capacity costs expressed in dollars per net kW per year of the utility's new supply options from paragraphs 35.9(6) "b" and "c" in each costing period.

RC (resalable capacity) is the value of existing capacity expressed in dollars per net kW per year that could be sold to other parties in each costing period.

RM (reserve margin) is the generation reserve margin criterion adopted by the utility.

DLF (demand loss factor) is the system demand loss factor, expressed as a fraction of the net power generated, purchased, or interchanged in each costing period. For example, the peak system demand loss factor would be equal to peak system power loss (MW) divided by the net system peak load (MW) for each costing period.

EF (externality factor) is a 10 percent factor applied to avoided capacity costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor, but must document its accuracy.

b. Avoided energy costs. Calculations of avoided energy costs in each costing period shall be based on the following formula:

AVOIDED ENERGY COSTS = MEC x (1 + ELF) x (1 + EF)

MEC (marginal energy cost) is the marginal energy cost expressed in dollars per kWh, inclusive of variable operations and maintenance costs, for electricity in each costing period.

ELF (system energy loss factor) is the system energy loss factor, expressed as a fraction of net energy generated, purchased, or interchanged in each costing period.

¹⁰⁶ Full Order available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45284-07.htm#P326_75353

EF (externality factor) is a 10 percent factor applied to avoided energy costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor, but must submit documentation of its accuracy.¹⁰⁷

Massachusetts

As the Department noted in the NOI at 10-11, cost-effectiveness tests traditionally have included benefits associated with the avoided electric generation and gas supply costs that result from the implementation of energy efficiency programs. The Department concludes that avoided electric generation and gas supply costs should continue to be included in cost-effectiveness analyses for both electric and gas programs, because, even in the restructured industries, these costs would continue to be directly incurred by users of the electric and gas systems absent the energy efficiency programs, as the Total Resource Cost Test recognizes. Therefore, the proposed Guidelines provide that avoided electric generation and gas supply costs be included in cost-effectiveness analyses. Electric and gas industry restructuring means that avoided energy costs may be incurred on a regional, rather than on a utility-specific, basis in the future. For example, before restructuring of the electric industry, the avoidance of generation costs through the implementation of energy efficiency programs served to lower the costs of a specific utility. All customers of the utility benefitted by the reduction in costs. After restructuring, the avoidance of generation costs through the implementation of energy efficiency programs may serve to lower costs of the electric system regionally. The Department understands that a working group from the Joint Commenters is developing consensus projections of avoided energy costs for use by program administrators. The Department expects that electric and gas distribution companies will file projections of avoided energy costs either in this proceeding after the Guidelines are final, or with their energy efficiency plans. In order to ensure that program cost-effectiveness is assessed using reasonably current avoided energy cost information, the attached Guidelines direct that projected energy cost values shall be updated at least bi-annually, or whenever information indicates that market conditions have changed substantially. An update may be proposed by a program administrator, DOER, or the Department.¹⁰⁸

(a) Avoided Electric Generation and Gas Supply Costs shall be calculated as the product of (1) a program's energy, commodity and capacity savings, as appropriate, and (2) an avoided electric generation or gas supply cost factor, as appropriate. The avoided electric generation factor shall be uniform for all Electric Companies and Municipal Aggregators and shall be updated biannually or as necessitated by changing market conditions, as approved by the Department. The avoided gas supply cost factor shall be based on the gas supply costs specific to each Natural Gas Local Distribution Company, except for those Energy Efficiency Programs that are jointly implemented, for which the avoided gas supply factor shall be based on the weighted average of the gas supply costs of the Natural Gas Local Distribution Companies participating in the program.

¹⁰⁷ Iowa Utilities Code 35.9(7). See <http://www.legis.state.ia.us/ACO/IAChtml/199.htm>

¹⁰⁸ DTE 98-100 Final Order re: cost-effectiveness, p. 16

<http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm>

(b) Avoided Transmission Costs shall be calculated as the product of (1) a program's energy and capacity savings, and (2) an avoided transmission cost factor. The avoided transmission cost factor shall be based on the transmission costs specific to each Distribution Company, except for those Energy Efficiency Programs that are jointly implemented, for which the avoided transmission cost factor shall be based on the weighted average of the transmission costs of the Distribution Companies participating in the program. For Energy Efficiency Programs that are targeted at specific locations within a Distribution Company's service territory, the avoided transmission cost factor may be based on transmission costs specific to the targeted locations.

(c) Avoided Distribution Costs shall be calculated as the product of (1) a program's energy, commodity and capacity savings, as appropriate, and (2) an avoided distribution cost factor. The avoided distribution cost factor shall be based on the distribution costs specific to each Distribution Company, except for those Energy Efficiency Programs that are jointly implemented, for which the avoided distribution cost factor shall be based on the weighted average of the distribution costs of the Distribution Companies participating in the program. For Energy Efficiency Programs that are targeted at specific locations within a Distribution Company's service territory, the avoided distribution cost factor shall be based on distribution costs specific to the targeted locations.

(d) Avoided Electric Generation and Gas Supply Costs, Avoided Transmission Costs, and Avoided Distribution Costs shall include environmental compliance costs that are reasonably projected to be incurred in the future because of rules and/or regulatory requirements that are not currently in effect, but which are projected to take effect in the foreseeable future. Avoided Projected Compliance Costs shall be calculated as the product of (1) a program's energy, commodity and capacity savings, as appropriate, and (2) an avoided cost factor that is calculated specific to each identified rule and/or regulatory requirement.¹⁰⁹

Texas

The avoided cost shall be the estimated cost of a new gas turbine. Initially, the avoided cost of capacity savings shall be set at \$78.5/kW saved annually at the customer's meter.

The avoided cost shall be the estimated cost of a new gas turbine.
(A) Initially, the avoided cost of capacity savings shall be set at \$78.5/kW saved annually at the customer's meter.

(B) Initially, the avoided cost energy savings shall be set at 2.68 cents/kWh saved annually at the customer's meter.¹¹⁰

¹⁰⁹ DTE 98-100 Final Order re: cost-effectiveness, Attachment 1. See

<http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm>

¹¹⁰ PUCT Rules 25.181. See <http://www.puc.state.tx.us/rules/subrules/electric/25.181/25.181.pdf>

Scenario Modeling

Pacific Northwest or NWPCC

In conducting its regional Portfolio Planning, the Northwest Power and Conservation Council (NWPCC) models a variety of scenarios¹¹¹ under a wide range of futures as part of its risk mitigation process. The cost of a given resource plan under a multiple futures provides a basis for considering cost-related uncertainty and risk.¹¹²

System Benefits Charges/Public Goods Charges

These non-bypassable charges, paid by electric or gas ratepayers, were first created by legislation or by utility regulators as a means of ensuring some level of public investment in clean energy in the face of electric industry restructuring. Well known market barriers such a high first cost, high discount rates, split incentives between the owner and occupiers of buildings, etc., limit customer investment in efficiency and prevent society from realizing the full benefits of all cost-effective efficiency. The SBC funds were established to assure continued investment in efficiency but, with a few exceptions, the funds amounted to less per annum than had been spent on efficiency by the previously integrated utility. More problematic, the SBC funds are disconnected from the ongoing economic analysis of future resource acquisition. Worse, these efficiency funds have become a target for state budget officials as a source of general revenue. SBC's can be useful policy but they need to be closely connected to the ongoing resource acquisition decisions.

Arizona

Demand-side management (“DSM”) is “the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner.” . . . DSM is addressed in three areas of the Settlement Agreement: in the funding, programs, plans and reporting provisions; in the study of rate design modifications; and in the competitive procurement process. . .

. . . Funding for DSM comes in both base rates (\$10 million per year) and through implementation of an adjustor (average of \$6 million per year). DSM funding will be used for “approved eligible DSM-related items,” including “energy-efficiency DSM programs,” a performance incentive, and low income bill assistance. APS is obligated to spend \$13 million in 2005 on DSM projects. . .

. . . The adjustor will collect DSM costs that are above the \$10 million annual level included in base rates. The adjustor rate will initially be set at zero, and will be adjusted

¹¹¹ For more information, see *The Role of Energy Efficiency in the Northwest*, a slide show from the NWPCC available at <http://www.raponline.org/Conferences/Minnesota/Presentations/EckmanMNPUC120605.pdf>

¹¹² *The Fifth Northwest Electric Power and Conservation Plan*. NWPCC, May 2005.

<http://www.nwcouncil.org/energy/powerplan/plan/Default.htm>. See Section 6 for information about risk assessment.

yearly on March 1, based upon the account balance and the appropriate kWh or kW charge. The DSM adjustor will apply to both standard offer and direct access customers.

On residential customers' bills, the DSM adjustor will be combined with the EPS adjustor and be called an "Environmental Benefits Surcharge."¹¹³

California

California's Public Goods Charge was initiated in 1996 as part of AB 1890, the state's restructuring act. While restructuring has been suspended, the PGC continues to be used to fund efficiency, renewable energy, and other projects. In addition, a 2003 CPUC Decision allocates a portion of each utility's procurement budgets to efficiency programs.

AB 1890 states:

(a) To ensure that the funding for the programs described in subdivision (b) and Section 382 are not commingled with other revenues, the commission shall require each electrical corporation to identify a separate rate component to collect the revenues used to fund these programs. The rate component shall be a nonbypassable element of the local distribution service and collected on the basis of usage. This rate component shall fall within the rate levels identified in subdivision (a) of Section 368.

(b) The commission shall allocate funds collected pursuant to subdivision (a), and any interest earned on collected funds, to programs which enhance system reliability and provide in-state benefits as follows:

(1) Cost-effective energy efficiency and conservation activities.

(2) Public interest research and development not adequately provided by competitive and regulated markets.

(3) In-state operation and development of existing and new and emerging renewable resource technologies defined as electricity produced from other than a conventional power source within the meaning of Section 2805, provided that a power source utilizing more than 25 percent fossil fuel may not be included.

(c) The Public Utilities Commission shall order the respective electrical corporations to collect and spend these funds, as follows:

(1) Cost-effective energy efficiency and conservation activities shall be funded at not less than the following levels commencing January 1, 1998, through December 31, 2001: for San Diego Gas and

Electric Company a level of thirty-two million dollars (\$32,000,000) per year; for Southern California Edison Company a level of ninety million dollars (\$90,000,000) for each of the years 1998, 1999, and 2000; fifty million dollars (\$50,000,000) for the year 2001; and for Pacific Gas and Electric Company a level of one hundred six million dollars (\$106,000,000) per year.¹¹⁴

¹¹³ ACC Docket E-01345A-03-0437, Order of April 7, 2005, pp. 19-21. Footnotes omitted, but one footnote indicates "APS will spend at least \$48 million during calendar years 2005-2007". See <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>

¹¹⁴ Assembly Bill 1890 (1996 Legislative Session), p. 43. See http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_bill_960924_chaptered.pdf

Decision 0312060, issued December 18, 2003, authorizes the use of procurement funds for energy efficiency programs:

This decision . . . authorizes the utilities to spend an additional \$245 million on utility energy efficiency programs that are included as elements of their procurement portfolios . . . The utilities will implement these energy-savings programs in lieu of purchasing procuring [sic] electricity. . .

Furthermore, this decision supports the emphasis on integrated resource planning called for in SB 1389, AB 58, and CPUC D.02-10-062 by facilitating integration of procurement-funded energy efficiency programs with other resource acquisition and demand reduction decisions. At the same time, this decision also supports the goals of promoting innovation in energy efficiency programs by providing maximum flexibility in administration of new energy efficiency resources available through utility procurement programs.¹¹⁵

Connecticut

Connecticut established its SBC as part of its 1998 restructuring legislation.

(a) On and after January 1, 2000, the Department of Public Utility Control shall assess or cause to be assessed a charge of three mills per kilowatt hour of electricity sold to each end use customer of an electric distribution company to be used to implement the program as provided in this section for conservation and load management programs but not for the amortization of costs incurred prior to July 1, 1997, for such conservation and load management programs. . .

(b) The electric distribution company shall establish an Energy Conservation and Load Management Fund which shall be held separate and apart from all other funds or accounts. Receipts from the charge imposed under subsection (a) of this section shall be deposited into the fund. Any balance remaining in the fund at the end of any fiscal year shall be carried forward in the fiscal year next succeeding. Disbursements from the fund by electric distribution companies to carry out the plan developed under subsection (d) of this section shall be authorized by the Department of Public Utility Control upon its approval of such plan.

(c) The Department of Public Utility Control shall appoint and convene an Energy Conservation Management Board which shall include representatives of: (1) An environmental group knowledgeable in energy conservation program collaboratives; (2) the Office of Consumer Counsel; (3) the Attorney General; (4) the Department of Environmental Protection; (5) the electric distribution companies in whose territories the activities take place for such programs; (6) a state-wide manufacturing association; (7) a chamber of commerce; (8) a state-wide business association; (9) a state-wide retail organization; and (10) residential customers. Such members shall serve for a period of five years and may be reappointed.¹¹⁶

Connecticut's 2005 Energy Independence Act revised the following section:

¹¹⁵ D. 0312060. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/32828-01.htm#P87_2557

¹¹⁶ Connecticut Statutes 16.245(m). See <http://www.cga.ct.gov/2005/pub/Chap283.htm#Sec16-245m.htm>.

(d) (1) The Energy Conservation Management Board shall advise and assist the electric distribution companies in the development and implementation of a comprehensive plan, which plan shall be approved by the Department of Public Utility Control, to implement cost-effective energy conservation programs and market transformation initiatives. The plan shall be consistent with the comprehensive energy plan approved by the Connecticut Energy Advisory Board pursuant to section 16a-7a at the time of submission to the department. Each program contained in the plan shall be reviewed by the electric distribution company and either accepted or rejected by the Energy Conservation Management Board prior to submission to the department for approval. The Energy Conservation Management Board shall, as part of its review, examine opportunities to offer joint programs providing similar efficiency measures that save more than one fuel resource or otherwise to coordinate programs targeted at saving more than one fuel resource. Any costs for joint programs shall be allocated equitably among the conservation programs. The Energy Conservation Management Board shall give preference to projects that maximize the reduction of federally mandated congestion charges¹¹⁷ ...

The Energy Independence Act also established an SBC for its municipal electric utilities:

Sec. 17. (NEW) (*Effective from passage*) (a) Each municipal electric utility created pursuant to chapter 101 of the general statutes or by special act shall, for investment in renewable energy sources and for conservation and load management programs pursuant to this section, accrue from each kilowatt hour of its metered firm electric retail sales, exclusive of such sales to United States government naval facilities in this state, no less than the following amounts during the following periods, in a manner conforming to the requirement of this section: (1) 1. 0 mills on and after January 1, 2006; (2) 1. 3 mills on and after January 1, 2007; (3) 1. 6 mills on and after January 1, 2008; (4) 1. 9 mills on and after January 1, 2009; (5) 2. 2 mills on and after January 1, 2010; and (6) 2. 5 mills on and after January 1, 2011.

(b) There is hereby created a Municipal Energy Conservation and Load Management Fund in each municipal electric energy cooperative created pursuant to chapter 101a of the general statutes, which fund shall be a separate and dedicated fund to be held and administered by such cooperative. Each municipal electric utility created pursuant to chapter 101 of the general statutes or by special act that is a member or participant in such a municipal electric energy cooperative shall accrue and deposit such amounts as specified in subsection (a) of this section into such fund. Any balance remaining in the fund at the end of any fiscal year shall be carried forward in the fiscal year next succeeding. Disbursements from the fund shall be made pursuant to the comprehensive electric conservation and load management plan prepared by the cooperative in accordance with subsection (c) of this section.

(c) Such cooperative shall, annually, adopt a comprehensive plan for the expenditure of such funds by the cooperative on behalf of such municipal electric utilities for the purpose of carrying out electric conservation, investments in renewable energy sources, energy efficiency and electric load management programs funded by the charge accrued

¹¹⁷ Connecticut Energy Independence Act, Section 5(d). See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

pursuant to subsection (a) of this section. The cooperative shall expend or cause to be expended the amounts held in such fund in conformity with the adopted plan. The plan may direct the expenditure of funds on facilities or measures located in any one or more of the service areas of the municipal electric utilities who are members or participants in such cooperative and may provide for the establishment of goals and standards for measuring the cost effectiveness of expenditures made from such fund, for the minimization of federally mandated congestion charges and for achieving appropriate geographic coverage and scope in each such service area. Such plan shall be consistent with the comprehensive plan of the Energy Conservation Management Board established under section 16-245m of the general statutes, as amended by this act. Such cooperative, annually, shall submit its plan to such board for review.¹¹⁸

District of Columbia

§ 34-1514. Reliable Energy Trust Fund; public purpose programs

(a) (1) There is hereby established the Reliable Energy Trust Fund, which shall be a proprietary fund in the nature of an enterprise fund as classified under § 47-373(a)

(2) The electric company shall remit all proceeds collected under subsection (b) of this section to the Mayor on a monthly basis. The Mayor shall deposit those proceeds into the Reliable Energy Trust Fund. All proceeds collected by the electric company under subsection (b) of this section shall be credited to the Reliable Energy Trust Fund without regard to fiscal year limitation and shall not at any time be transferred to, lapse into, or be commingled with the General Fund of the District of Columbia or any other fund or account of the District of Columbia.

(3) All interest earned on monies deposited in the Reliable Energy Trust Fund shall be credited to the Reliable Energy Trust Fund and shall be used solely for the purposes designated in this section.

(4) All revenue credited to the Reliable Energy Trust Fund shall be used solely to fund the programs mandated by subsection (c) of this section.

(b)(1) All customers other than those participating in the universal service program established under subsection (c)(1)(A) of this section shall contribute to the Reliable Energy Trust Fund through a non-bypassable charge collected by the electric company.

(2)(A) The charge mandated by paragraph (1) of this subsection shall be determined by the Commission and may not vary by customer class.

(B) Notwithstanding any other provision of this chapter, for 4 years after the initial implementation date, the charge mandated by this subsection shall not exceed \$0.0008 per kilowatt-hour.

(C) After the 4-year period designated in subparagraph (B) of this paragraph, the charge mandated by paragraph (1) of this subsection shall not exceed \$0.002 per kilowatt-hour, but shall not be less than \$.0001 per kilowatt hour. Collection shall commence as of February 1, 2005.

(3) On an annual basis, the Commission shall evaluate the charge mandated by paragraph (1) of this subsection to determine whether it is set at an appropriate level to fund the programs mandated by subsection (c) of this section. Subject to the restriction in paragraph (2) of this subsection, the Commission may adjust the charge if the Commission finds that the charge is not set at an appropriate level.

¹¹⁸ Ibid, section 17.

- (c)(1)(A) The Commission shall establish a universal service program to assist low-income customers in the District of Columbia.
- (B) The program established under to subparagraph (A) of this paragraph shall be administered by the District of Columbia Office of Energy.
- (2)(A) The Commission shall establish a program to promote energy efficiency in the District of Columbia.
- (B) The program established by the Commission under subparagraph (A) of this paragraph may include:
- (i) Rate discounts or other rate-related incentives;
 - (ii) Financing of activities of energy service companies;
 - (iii) Certification standards for energy service companies;
 - (iv) Financial incentives for owners of low-income residential properties; and
 - (v) Energy efficiency assistance to customers who qualify for the universal service program under subparagraph (A) of this paragraph.
- (C) In the discretion of the Commission, the energy efficiency program established under subparagraph (A) of this paragraph may be administered by the District of Columbia Office of Energy.
- (3) The Commission shall establish a program to promote the use of electricity from renewable energy sources as defined in § 34-1517. The program established under this paragraph may include the use of rebates to customers who purchase electricity from renewable energy sources as defined in § 34- 1518.¹¹⁹

The Commission authorized funding levels of \$2.3 million annually for the first four years of the program. In 2005, the D.C. Commission raised the annual funding levels for 2005-2006 to \$9.5 million and \$10.5 million for 2005 and 2006, respectively.¹²⁰

Illinois

Illinois electric utilities are required by statute to pay into an Energy Efficiency Trust Fund:

For the year beginning January 1, 1998, and thereafter as provided in this Section, each electric utility as defined in Section 3-105 of the Public Utilities Act and each alternative retail electric supplier as defined in Section 16-102 of the Public Utilities Act supplying electric power and energy to retail customers located in the State of Illinois shall contribute annually a pro rata share of a total amount of \$ 3,000,000 based upon the number of kilowatt-hours sold by each such entity in the 12 months preceding the year of contribution. . . .

The Department of Commerce and Community Affairs shall disburse the moneys in the Energy Efficiency Trust Fund to benefit residential electric customers through projects which the Department of Commerce and Community Affairs has determined will promote energy efficiency in the State of Illinois. The Department of Commerce and

¹¹⁹ DC ST Sec. 34-354. See

http://weblinks.westlaw.com/Find/Default.wl?DB=DC%2DST%2DTC%3BSTADCTOC&DocName=DCCODES34%2D1514&FindType=W&AP=&fn=_top&rs=WEBL6.08&vr=2.0&spa=DCC-1000&trailtype=26

¹²⁰ DC PSC Order No. 13475, issued March 7, 2005. Discussion of funding levels is on pp. 60-62. See http://www.dcpsc.org/pdf_files/commorders/orderpdf/orderno_13475_FC945.pdf

Community Affairs shall establish a list of projects eligible for grants from the Energy Efficiency Trust Fund including, but not limited to, supporting energy efficiency efforts for low-income households, replacing energy inefficient windows with more efficient windows, replacing energy inefficient appliances with more efficient appliances, replacing energy inefficient lighting with more efficient lighting, insulating dwellings and buildings, using market incentives to encourage energy efficiency, and such other projects which will increase energy efficiency in homes and rental properties.¹²¹

Maine

Maine's System Benefits Charge is required by statute:

Funding level. The commission shall assess transmission and distribution utilities to collect funds for conservation programs and administrative costs in accordance with this subsection. The amount of all assessments by the commission under this subsection plus expenditures of a transmission and distribution utility associated with prior conservation efforts must result in total conservation expenditures by each transmission and distribution utility that:

- A. Are based on the relevant characteristics of the transmission and distribution utility's service territory, including the needs of customers;
- B. Do not exceed .145 cent per kilowatt-hour;
- C. Except as provided in subsection 7-A, are no less than 0.5% of the total transmission and distribution revenues of the transmission and distribution utility; and
- D. Are proportionally equivalent on a per-kilowatt-hour basis to the total conservation expenditures of other transmission and distribution utilities, unless the commission finds that a different amount is justified.¹²²

Massachusetts

GLc 164, Massachusetts' 1997 restructuring act (the 1997 Act) replaced the state's regulatory wires charge with a statutory wires charge to fund energy efficiency programs. The initial program was authorized through 2003. A 2002 Act (quoted below) extended the program through 2008. Chapter 140 of the Acts of 2005 further extended the program through 2012¹²³.

Section 19. Beginning on March 1, 1998, and for a period of ten years thereafter, the department is authorized and directed to require a mandatory charge per kilowatt-hour for all consumers of the commonwealth, except those served by a municipal lighting plant, to fund energy efficiency activities, including, but not limited to, demand-side management programs. Said charge shall be the following amounts: 3.3 mills (\$0.0033) per kilowatt-hour for calendar year 1998; 3.1 mills (\$0.0031) per kilowatt-hour for calendar year 1999; 2.85 mills (\$0.00285) per kilowatt-hour for calendar year 2000; 2.7 mills (\$0.0027)

¹²¹ Illinois Compiled Statutes, 20-687.6-6. See

<http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=002006870K6-6>

¹²² Maine Statute Title 35-A, Chapter 32 Section 3211. See <http://janus.state.me.us/legis/statutes/35-a/title35-asec3211-a.html>

¹²³ Massachusetts General Statutes had not been updated to reflect the 2005 Act at the time of this writing. The 2005 Act is available at <http://www.mass.gov/legis/laws/seslaw05/sl050140.htm>.

per kilowatt-hour for calendar year 2001; and 2.5 mills (\$0.0025) per kilowatt-hour for calendar years 2002 to 2007 inclusive; provided, however, that in authorizing such programs the department shall ensure that they are delivered in a cost-effective manner utilizing competitive procurement processes to the fullest extent practicable. At least 20 per cent of the amount expended for residential demand-side management programs by each distribution company in any year, and in no event less than the amount funded by a charge of 0.25 mills per kilowatt-hour, which charge shall also be continued in the years subsequent to 2002, shall be spent on comprehensive low-income residential demand-side management and education programs. A distribution company shall not be allowed to assess any other charge relative to energy efficiency programs which would exceed the levels permitted herein.¹²⁴

Minnesota

Each public utility shall spend and invest for energy conservation improvements under this subdivision and subdivision 2 the following amounts:

- (1) for a utility that furnishes gas service, 0.5 percent of its gross operating revenues from service provided in the state;
- (2) for a utility that furnishes electric service, 1.5 percent of its gross operating revenues from service provided in the state; and
- (3) for a utility that furnishes electric service and that operates a nuclear-powered electric generating plant within the state, two percent of its gross operating revenues from service provided in the state.¹²⁵

Montana

Montana's "universal system benefits" program was statutorily established in 1998 as part of the state's restructuring legislation.¹²⁶ The original legislation established the program through 2003; legislation in 2001 and 2005 extended it through 2005 and 2009, respectively.

69-8-402. Universal system benefits programs. (1) Universal system benefits programs are established for the state of Montana to ensure continued funding of and new expenditures for energy conservation, renewable resource projects and applications, and low-income energy assistance.

(2) Beginning January 1, 1999, 2.4% of each utility's annual retail sales revenue in Montana for the calendar year ending December 31, 1995, is established as the initial funding level for universal system benefits programs. To collect this amount of funds on an annualized basis in 1999, the commission shall establish rates for utilities subject to its jurisdiction and the governing boards of cooperatives shall establish rates for the

¹²⁴ General Laws of Massachusetts, Chapter 25, Section 19. See <http://www.mass.gov/legis/laws/mglorg/mgl/25-19.htm>

¹²⁵ Minnesota Statutes 2005, 216B.24 1 Subd. 1a. See <http://www.revisor.leg.state.mn.us/stats/216B/241.html>.

¹²⁶ Full retail access has been delayed in Montana. Currently, one of the state's two major electric utilities is restructured, while the other major electric utility is traditionally regulated. Both utilities pay into the fund.

cooperatives. These universal system benefits charge rates must remain in effect through December 31, 2009.¹²⁷

New Hampshire

New Hampshire's 1996 restructuring legislation included the establishment of a system benefits charge:

VI. Benefits for All Consumers. Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers. A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, but not necessarily be limited to, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investments in commercialization strategies for new and beneficial technologies.¹²⁸

The 1996 statute had established caps on the SBC of \$.0025/kWh and \$.003/kWh cap for the first and second years, respectively. A 2002 statute replaced these caps by fixing the SBC at \$.002/kWh:

(6) The total system benefits charge shall be fixed at \$0.002 per kilowatt-hour for 33 months from competition day divided between low-income assistance and energy efficiency/conservation programs. In the event that the commission finds that a significant amount of unencumbered dollars have accumulated in either program, and are not needed for program purposes, the commission shall refund such unencumbered dollars to ratepayers in a timely manner.¹²⁹

Allocation of SBC funds between low-income assistance and energy efficiency programs is determined by the PUC. In 2000, the PUC established these levels in Order 23,575:

In the absence of a comprehensive and formal analysis of the most effective level of program funding, and until the programs have been implemented and experience is gained, allocating the SBC between low income and energy efficiency/conservation funding on a \$0.00120 to \$0.0080 per kWh basis is in the public interest.¹³⁰

A 2005 statute raised the overall SBC funding level to \$.003/kWh¹³¹, extended the SBC through 2008, and established a cap on the low-income portion of the SBC:

¹²⁷ Montana Code Annotated 69.8.402. See <http://data.opi.state.mt.us/bills/mca/69/8/69-8-402.htm>

¹²⁸ New Hampshire Statutes, Chapter 374-F:3. VI. See <http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-3.htm>

¹²⁹ SB 472, amending Chapter 369-B:3(IV)(b)(6) See <http://www.gencourt.state.nh.us/legislation/2000/sb0472.html>

¹³⁰ New Hampshire Public Utilities Commission Order No. 23,575, p. 16. See <http://www.puc.state.nh.us/Regulatory/Orders/2000ords/23575e.pdf>

¹³¹ See Chapter 369-B:3(IV)(b)(6) at <http://www.gencourt.state.nh.us/rsa/html/XXXIV/369-B/369-B-3.htm>

(c) The portion of the system benefits charge due to programs for low-income customers shall not exceed 1.5 mills per kilowatt hour. The authority of the commission to impose such a charge shall terminate on June 30, 2008.¹³²

New Jersey

New Jersey's system benefits charge was established when the state restructured in 1999. Initial funding levels were set at a level equal to then-current DSM funding. However, the SBC was intended to fund not only DSM programs, but also for social and other programs that had been granted prior approval by the Board, including nuclear decommissioning costs and gas plant remediation costs. The SBC legislation specifies that the portion of funds allocated to DSM programs should increase as other obligations expire.

Simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, the board shall permit each electric public utility and gas public utility to recover some or all of the following costs through a societal benefits charge that shall be collected as a non-bypassable charge imposed on all electric public utility customers and gas public utility customers, as appropriate:

. . . . The costs of demand side management programs that were approved by the board pursuant to its demand side management regulations prior to April 30, 1997. For the purpose of establishing initial unbundled rates pursuant to section 4 of this act, the societal benefits charge shall be set to recover the same level of demand side management program costs as is being collected in the bundled rates of the electric public utility on the effective date of this act. Within four months of the effective date of this act, and every four years thereafter, the board shall initiate a proceeding and cause to be undertaken a comprehensive resource analysis of energy programs, and within eight months of initiating such proceeding and after notice, provision of the opportunity for public comment, and public hearing, the board, in consultation with the Department of Environmental Protection, shall determine the appropriate level of funding for energy efficiency and Class I renewable energy programs that provide environmental benefits above and beyond those provided by standard offer or similar programs in effect as of the effective date of this act; provided that the funding for such programs be no less than 50% of the total Statewide amount being collected in public electric and gas utility rates for demand side management programs on the effective date of this act for an initial period of four years from the issuance of the first comprehensive resource analysis following the effective date of this act, and provided that 25% of this amount shall be used to provide funding for Class I renewable energy projects in the State. In each of the following fifth through eighth years, the Statewide funding for such programs shall be no less than 50 percent of the total Statewide amount being collected in public electric and gas utility rates for demand side management programs on the effective date of this act, except that as additional funds are made available as a result of the expiration of past standard offer or similar commitments, the minimum amount of funding for such programs shall increase by an additional amount equal to 50 percent of the additional

¹³² New Hampshire Statutes, Chapter 374-F:4(VIII)(c). See <http://www.gencourt.state.nh.us/rsa/html/XXXIV/374-F/374-F-4.htm>

funds made available, until the minimum amount of funding dedicated to such programs reaches \$140,000,000 total. After the eighth year the board shall make a determination as to the appropriate level of funding for these programs. Such programs shall include a program to provide financial incentives for the installation of Class I renewable energy projects in the State, and the board, in consultation with the Department of Environmental Protection, shall determine the level and total amount of such incentives as well as the renewable technologies eligible for such incentives which shall include, at a minimum, photovoltaic, wind, and fuel cells. The board shall simultaneously determine, as a result of the comprehensive resource analysis, the programs to be funded by the societal benefits charge, the level of cost recovery and performance incentives for old and new programs and whether the recovery of demand side management programs' costs currently approved by the board may be reduced or extended over a longer period of time. The board shall make these determinations taking into consideration existing market barriers and environmental benefits, with the objective of transforming markets, capturing lost opportunities, making energy services more affordable for low income customers and eliminating subsidies for programs that can be delivered in the marketplace without electric public utility and gas public utility customer funding. . .¹³³

New Mexico

A. A public utility that undertakes cost-effective energy efficiency and load management programs shall recover the costs of all the programs implemented after the effective date of the Efficient Use of Energy Act through an approved tariff rider. Program costs may be deferred for future recovery through creation of a regulatory asset, provided that the deferred recovery does not cause the tariff rider to exceed the limits imposed by this section. The tariff rider for any utility customer shall not exceed the lower of one and one-half percent of that customer's bill or seventy-five thousand dollars (\$75,000) per year except that, upon application by a public utility with the advice and consent of the entity designated by law to represent residential and commercial utility customers, the commission may approve a tariff rider in excess of one and one-half percent for customers other than large customers and may approve a tariff rider in excess of the lower of one and one-half percent or seventy-five thousand dollars (\$75,000) per year for a large customer that consents to such a rider. The commission shall approve such applications upon finding that the proposed energy efficiency and load management programs are cost-effective and that the cost recovery proposal is just and reasonable.

B. The tariff rider shall provide for the recovery, on a monthly basis or otherwise, of all reasonable costs of approved energy efficiency and load management programs.¹³⁴

¹³³ NJSA 48:3-60. See http://lis.njleg.state.nj.us/cgi-bin/om_isapi.dll?clientID=19722999&Depth=2&depth=2&expandheadings=on&headingswithhits=on&hitsperheading=on&infobase=statutes.nfo&record={133E0}&softpage=Doc_Frame_PG42

¹³⁴ New Mexico Statutes, Chapter 62-17-6. See <http://www.conwaygreene.com/nmsu/lpext.dll?f=templates&fn=main-hit-h.htm&2.0>

New York

New York's Public Service Commission (PSC) established its SBC in 1997, when the state restructured. Opinion 96-12 states:

Any restructuring model should include a mechanism for recovering costs required to be spent on environmental and other public policy considerations that would not otherwise be recovered in a competitive market. A non-bypassable system benefits charge appears to be a fair way of ensuring that such programs can be continued. These matters should be thoroughly considered in the context of individual utility filings. . .¹³⁵

A system benefits charge would provide a funding source during the transition, and possibly over the long term, for public policy initiatives that are not expected to be adequately addressed by competitive markets. It would be designed to ensure that the cost of carrying out these public policy initiatives was fairly allocated across most, if not all, users of the power distribution system, and recovered in a competitively neutral manner.

Initially, the system benefits charge would be set at approximately the level of current utility expenditures, with the expectation that these charges will be closely scrutinized with respect to their impacts on rates. Programs funded in this way, along with the innovative programs likely to be developed by energy service companies, provide ample reason to be confident, as we are, that cost-effective energy conservation measures, including demand side management, will flourish in the new environment. We anticipate the levels of energy efficiency programs accomplished in this way will be higher than existing levels.

In light of the potential benefits, a system benefits charge should be put in place during the transition to retail competition. The use of a system benefits charge should be revisited sometime after retail competition has commenced to determine whether the level of these programs is sufficient and whether the continued use of a system benefits charge is required.

To ensure that funding is provided consistent with our policy and that any fund is administered properly, we will continue to oversee these programs.¹³⁶

Initially, SBC rates were established in rate cases for individual utilities. In 1998 the PSC named the New York State Energy Research and Development Authority as the third-party administrator of SBC funds:

We expect the use of a third party fund administrator will produce economies in fund management by eliminating duplicative tasks and cumbersome decision making and will ensure that the funds are administered in a competitively neutral manner. Administrative costs should further be reduced by using an entity that already has a structure in place for implementing such programs. New York State Energy Research and Development

¹³⁵ New York PSC Opinion 96-12, p. 63 See <http://www.dps.state.ny.us/sbc.htm#SBC%20Background%202005>

¹³⁶ Ibid, p. 66-67.

Authority (NYSERDA) stands foremost among existing entities in having an established organization that is experienced in delivering public benefit energy efficiency, environmental and R&D programs on a statewide basis. As a non-profit entity, NYSERDA can further maintain neutrality in administration of SBC funds. We therefore designate NYSERDA as the SBC fund administrator.

Each of the utilities is directed to enter into such contracts or agreements with NYSERDA as are necessary to fulfill its obligations, under the terms of its settlement agreement and this Order, to implement our choice of NYSERDA as the administrator of SBC funds. The terms of such contracts or agreements shall provide that SBC monies collected by the utility through its rates will be transferred to NYSERDA to fund SBC programs that we approve.¹³⁷

In 2001, the PSC extended the SBC's time frame and funding levels:

Based upon its view of the status and pace of the development of competitive electricity markets, the sound performance of NYSERDA and of the SBC programs, the remaining barriers to market provision of public benefit programs, and the need to add electric load reduction and outreach and education components, Staff recommended a continuation of the SBC program for five years. We agree with that view. . .

Many barriers to the provision of these services by the marketplace remain, and are discussed and described more fully in the New York SBC Evaluation Report. In the area of energy efficiency, these barriers include high initial costs of implementation, lack of information and capital, and low stocking, promotion and advertising of energy efficiency products.¹³⁸

The Commission orders:

1. The System Benefits Charge (SBC) is continued for an additional five years from July 1, 2001 to June 30, 2006.
2. Beginning with calendar year 2001, the annual level of overall SBC funding is increased from approximately \$78.1 million, as previously established, to \$150 million, as approved herein.¹³⁹

Oregon

Oregon's 1999 restructuring legislation, SB1149, established a public purpose charge (PPC):

SECTION 3. (1) There is established an annual public purpose expenditure standard for electric companies to fund new cost-effective local energy conservation, new market

¹³⁷ New York PSC Opinion 98-3, p. 11. See <http://www.dps.state.ny.us/sbc.htm#SBC%20Background%202005>

¹³⁸ ORDER CONTINUING AND EXPANDING THE SYSTEM BENEFITS CHARGE FOR PUBLIC BENEFIT PROGRAMS, January 26, 2001, p. 6. Online at [http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ArticlesByCategory/98254B5953E8F4AC85256DF10075626B/\\$File/doc9157.pdf?OpenElement](http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/ArticlesByCategory/98254B5953E8F4AC85256DF10075626B/$File/doc9157.pdf?OpenElement)

¹³⁹ *Ibid.*, p. 26

transformation efforts, the above-market costs of new renewable energy resources, and new low-income weatherization. The public purpose expenditure standard shall be funded by the public purpose charge described in subsection (2) of this section.

(2)(a) Beginning on the date an electric company offers direct access to its retail electricity consumers, except residential electricity consumers, the electric company shall collect a public purpose charge from all of the retail electricity consumers located within its service area for a period of 10 years. Except as provided in paragraph (b) of this subsection, the public purpose charge shall be equal to three percent of the total revenues collected by the electric company or electricity service supplier from its retail electricity consumers for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs included in electric rates on the effective date of this 1999 Act.

(b) For an aluminum plant that averages more than 100 average megawatts of electricity use per year, beginning on October 1, 2001, the electric company whose territory abuts the greatest percentage of the site of the aluminum plant shall collect from the aluminum company a public purpose charge equal to one percent of the total revenue from the sale of electricity services to the aluminum plant from any source.

(3)(a) The Public Utility Commission shall establish rules implementing the provisions of this section relating to electric companies.

(b) Subject to paragraph (e) of this subsection, funds collected by an electric company through public purpose charges shall be allocated as follows:

(A) Sixty-three percent for new cost-effective conservation and new market transformation;

(B) Nineteen percent for the above-market costs of new renewable energy resources.

(C) Thirteen percent for new low-income weatherization.

(D) Five percent shall be transferred to the Housing and Community Services Department Revolving Account created under ORS 456.574 and used for the purpose of providing grants as described in ORS 458.625 (2). Moneys deposited in the account under this subparagraph are continuously appropriated to the Housing and Community Services Department for the purposes of ORS 458.625 (2). Interest on moneys deposited in the account under this subparagraph shall accrue to the account.

(c) The costs of administering subsections (1) to (6) of this section for an electric company shall be paid out of the funds collected through public purpose charges. The commission may require that an electric company direct funds collected through public purpose charges to the state agencies responsible for implementing subsections (1) to (6) of this section in order to pay the costs of administering such responsibilities.

(d) The commission shall direct the manner in which public purpose charges are collected and spent by an electric company and may require an electric company to expend funds through competitive bids or other means designed to encourage competition, except that funds dedicated for low-income weatherization shall be directed to the Housing and Community Services Department as provided in subsection (7) of this section. The commission may also direct that funds collected by an electric company through public purpose charges be paid to a nongovernmental entity for investment in public purposes described in subsection (1) of this section. Notwithstanding any other provision of this

subsection, at least 80 percent of the funds allocated for conservation shall be spent within the service area of the electric company that collected the funds.¹⁴⁰

Pennsylvania

Pennsylvania's 1995 restructuring legislation established a system benefits charge to fund low income assistance, including low income energy efficiency programs. Individual utility "universal service charges" were established in PUC-approved settlement agreements.

(a) General Rule.--Electric cooperative corporations shall ensure that universal service and energy conservation policies, activities and services that they provide as of the effective date of this chapter to assist customers who are low-income to afford electric service, are appropriately funded and available within their territories. Such activities shall be funded by nonbypassable, competitively-neutral cost recovery mechanisms that fully recover the costs of universal service and energy conservation services.

(b) Definition.--As used in this section, the term "universal service and energy conservation" shall mean policies, protections and services that help low-income customers to maintain electric service, including customer assistance programs and policies and services that help low-income customers to reduce or manage energy consumption in a cost-effective manner, such as the low-income usage reduction programs and customer education.¹⁴¹

Rhode Island

Rhode Island's restructuring legislation established a minimum SBC of 2.3 mills for five years. In 2001, the SBC was extended for an additional five years.

(b) Effective as of January 1, 2003, and for a period of ten (10) years thereafter, each electric distribution company shall include charges of 2.0 mills per kilowatt-hour delivered to fund demand side management programs and 0.3 mills per kilowatt-hour delivered to fund renewable energy programs. Existing charges for these purposes and their method of administration shall continue through December 31, 2002. Thereafter, the electric distribution company shall establish two (2) separate accounts, one for demand side management programs, which shall be administered and implemented by the distribution company, subject to the regulatory reviewing authority of the commission, and one for renewable energy programs, which shall be administered by the state energy office.

During the ten (10) year period the commission may, in its discretion, after notice and public hearing, increase the sums for demand side management and renewable resources; thereafter, the commission shall, after notice and public hearing, determine the appropriate charge for these programs. The energy office and the administrator of the renewable energy programs shall seek to secure for the state an equitable and reasonable portion of renewable energy credits or certificates created by projects funded through

¹⁴⁰ 1999 Oregon Legislative Session SB 1149. See <http://www.energytrust.org/library/policies/sb1149.pdf>

¹⁴¹ Pennsylvania statutes, Title 15, Sec. 7409. See <http://members.aol.com/StatutesPA/15.Cp.74.html>.

those programs. As used in this section, "renewable energy resources" shall mean power generation technologies as defined in § 39-26-5, "eligible renewable energy resources". Technologies for converting solar energy for space heating or generating domestic hot water may also be funded through the renewable energy programs, so long as these technologies are installed on housing projects that have been certified by the executive director of the Rhode Island housing and mortgage finance corporation as serving low-income Rhode Island residents. Fuel cells may be considered an energy efficiency technology to be included in demand sided management programs.¹⁴²

2006 legislation added an SBC for gas utilities:

(d) Effective January 1, 2007, and for a period of seven (7) years thereafter, each gas distribution company shall include, with the approval of the commission, a charge of up to fifteen cents (\$0.15) per deca therm delivered to demand side management programs, including, but not limited to, programs for cost-effective energy efficiency, energy conservation, combined heat and power systems, and weatherization services for low income households.

(e) The gas company shall establish a separate account for demand side management programs, which shall be administered and implemented by the distribution company, subject to the regulatory reviewing authority of the commission. The commission may establish administrative mechanisms and procedures that are similar to those for electric demand side management programs administered under the jurisdiction of the commissions and that are designed to achieve cost-effectiveness and high life-time savings of efficiency measures supported by the program.¹⁴³

Vermont

Vermont's Energy Efficiency Charge (EEC) was created in 1999 through legislation and by PSB Order. The EEC was initially considered as part of potential statewide restructuring. The state remains fully integrated. The 1999 legislation established a funding cap of \$17.5 million.

(3) In addition to its existing authority, the board may establish by order or rule a volumetric charge to customers for the support of energy efficiency programs that meet the requirements of section 218c¹⁴⁴ of this title. The charge shall be known as the energy efficiency charge, shall be shown separately on each customer's bill, and shall be paid to a fund administrator appointed by the board. When such a charge is shown, notice as to how to obtain information about energy efficiency programs approved under this section shall be provided in a manner directed by the board. This notice shall include, at a minimum, a toll free telephone number, and to the extent feasible shall be on the customer's bill and near the energy efficiency charge. Funds collected through an energy efficiency charge shall not be funds of the state, shall not be available to meet the general obligations of the government, and shall not be included in the financial reports of the state. The board will annually provide the legislature with a report detailing the revenues collected and the expenditures made for energy efficiency programs under this section.

¹⁴² Rhode Island Code 39-2-1.2. See <http://www.rilin.state.ri.us/Statutes/TITLE39/39-2/39-2-1.2.HTM>

¹⁴³ Rhode Island Code 39-2-1.2. See also H8205 text at <http://www.rilin.state.ri.us/Billtext/BillText06/HouseText06/H8025Aaa.pdf>

¹⁴⁴ V.S.A. 218c contains Vermont's Integrated Resource Planning rules.

(4) The charge established by the board pursuant to subdivision (3) of this subsection shall not exceed the amount needed to provide \$17,500,000.00 to support all energy efficiency programs for Vermonters authorized by the board by rule or order pursuant to subdivision (2) of this subsection in any fiscal year. No more than \$17,500,000.00 of financial support for energy efficiency programs for Vermonters shall be authorized by the board by rule or order pursuant to subdivision (2) of this subsection in any fiscal year.¹⁴⁵

In 2002, the PSB revised the methodology for calculating the EEC, establishing a uniform charge per kWh:

Using the methodology described in Attachment A to the Stipulation, and making the adjustments required by Paragraphs 11 and 12 of the Stipulation, results in the following EEC rates, for all distribution utility service territories except those of BED, WEC, and CVPS¹⁴⁶:

- a. For residential customers, the EEC should be 3.688 mills/kWh.
- b. For non-residential customers who are not demand billed, the EEC should be 2.951 mills/kWh.
- c. For non-residential customers who are demand billed, the EEC will be 1.887 mills/kWh and \$0.4310/kW per month. The kW month charge will be assessed on billed peak kW only.
- d. For unmetered street and security lighting customers, the EEC should be equal to or the equivalent of 2.951 mills/kWh times the nominal size of the light times 360 hours per month.¹⁴⁷

The methodology for calculating the year 2003 EEC that we approve in this Order results in business and other non-residential customers paying 56 percent of the total amount collected via the EEC in 2003, even though they use 62 percent of Vermont's electricity. By contrast, under this methodology, residential customers will pay 44 percent of the total amount collected via the EEC in 2003, even though they only use 38 percent of Vermont's electricity. Under this methodology, the proportions paid by both business and residential customers are the same for the year 2003 as they were in the year 2002.

This differs from the DPS's original proposed calculation methodology for the year 2003 EEC, which would have significantly increased the proportion of the total amount collected via the EEC in 2003 paid by businesses and other non-residential customers as compared with 2002. After hearing the DPS describe this methodology at the public hearing, three major industrial ratepayers expressed concern with any calculation methodology that would increase the amount of the EEC that they would have to pay. In addition, following the public hearing, the Board received numerous letters and e-mail

¹⁴⁵ S.137 of the 1999 Legislative Session. See <http://www.leg.state.vt.us/DOCS/2000/ACTS/ACT060.HTM>

¹⁴⁶ Two utilities had not yet signed the MOU at the time of the Order, and one utility opted to deliver its own efficiency services. The EEC for these three utilities was determined differently.

¹⁴⁷ Docket 6741, Order of 10/31/02, p. 8. See

<http://www.state.vt.us/psb/orders/2002/files/6741orderapprovingeec.pdf>

messages from customers who opposed the establishment of a methodology which would result in businesses and other non-residential customers paying a larger share of the total amount collected via the EEC in 2003 than they did in 2002.

After receiving these comments from ratepayers, the DPS changed its proposed methodology to address these concerns. Specifically, the DPS reduced the portion of the total amount to be collected via the EEC in 2003 that would be paid by businesses and other nonresidential customers to the same as in 2002.¹⁴⁸

2005 legislation lifted the \$17.5 million cap on funding. For 2006 and beyond, the PSB will determine the amount of the EEC based on legislative directive, as currently stated in the statute, which now reads:

(4) The charge established by the board pursuant to subdivision (3) of this subsection shall be in an amount determined by the board by rule or order that is consistent with the principles of least cost integrated planning as defined in section 218c of this title. As circumstances and programs evolve, the amount of the charge shall be reviewed for unrealized energy efficiency potential and shall be adjusted as necessary in order to realize all reasonably available, cost-effective energy efficiency savings. In setting the amount of the charge and its allocation, the board shall determine an appropriate balance among the following objectives: providing efficiency and conservation as a part of a comprehensive resource supply strategy; providing the opportunity for all Vermonters to participate in efficiency and conservation programs; and the value of targeting efficiency and conservation efforts to locations, markets or customers where they may provide the greatest value.¹⁴⁹

In August 2006, the Commission established new funding amounts for 2006-2008:

In this Order we establish the Energy Efficiency Utility ("EEU") budgets for 2006, 2007 and 2008 and announce a subsequent process to develop a means of financing energy efficiency services to reduce the impact of the Energy Efficiency Charge ("EEC") on electricity rates in the near term. This Order is the outcome of a comprehensive, ten-month-long workshop process that followed Legislative action removing the former cap of \$17.5 million on the annual EEU budget and requiring the Board to set a new level based on objectives and criteria in the law. In this Order we raise the 2006 funding level to \$19.5 million, and establish funding levels of \$24 million and \$30.75 million for 2007 and 2008, respectively. We also conclude that higher funding levels may be appropriate, if the effect of those levels on electricity rates in the near term can be reduced. . .

In this Order we conclude that the current budget of \$17.5 million is insufficient to acquire all reasonably-available, cost-effective energy efficiency. The new budget levels that we set today will enable the EEU to work in the short-range toward minimizing lost

¹⁴⁸ Ibid., p. 33 (Footnotes omitted).

¹⁴⁹ 30 V.S.A. § 209 (d)(4). See

<http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209>

savings opportunities while still providing training to contractors, business customers and partners that is necessary for long-term market transformation. . . .

Balancing all factors, we set the EEU budget and simultaneously announce that we will reconsider in 15 months, or sooner, the established funding level for 2008. During that period, the Board will conduct a process to determine the range and feasibility of various ways to finance energy efficiency, through means such as bonding or securitization, to mitigate the short-term rate impacts of investing in energy efficiency. . .

In announcing our intention to consider long-term financing for energy efficiency, we note that state policy supports the treatment of efficiency comparably to supply resources, such as generation and transmission, in regional and federal policy. The initial capital costs of supply resources are typically paid for by issuing equity or bonds, which are paid off over time. In contrast, the current practice for energy efficiency is to expense the entire investment in the year it is incurred, even though the energy savings extend for many years. Creating a means to finance energy efficiency would result in comparable treatment of efficiency and supply-side costs by amortizing rather than expensing efficiency investments.¹⁵⁰

Wisconsin

1999 legislation transferred public benefits program administration from the utilities to the Wisconsin Department of Administration (DOA) and established a dual funding mechanism for the programs. 1998 funding levels were gradually transferred from utilities to DOA as utility-administered DSM was phased out. The legislation also established a new public benefits fee. Both mechanisms are described below:

- (2)** The commission shall determine the amount that each utility spent in 1998 on programs for each of the following:
- (a) Low-income assistance, including low-income weatherization and writing off uncollectibles and arrearages.
 - (b) Energy conservation and efficiency.
 - (c) Environmental research and development.
 - (d) Renewable resources.

(3) In 2000, 2001 and 2002, the commission shall require each utility to spend a decreasing portion of the amount determined under sub. (2) on programs specified in sub. (2) and contribute the remaining portion of the amount to the commission for deposit in the fund. In each year after 2002, each utility shall contribute the entire amount determined under sub. (2) to the commission for deposit in the fund. The commission shall ensure in rate-making orders that a utility recovers from its ratepayers the amounts spent on programs or contributed to the fund under this subsection. The commission shall allow each utility the option of continuing to use, until January 1, 2002, the moneys that it has recovered under s. 196.374 (3), 1997 stats., to administer the programs that it has funded under s. 196.374 (1), 1997 stats. The commission may allow each utility to spend

¹⁵⁰ Vermont PSB Order of August 2, 2006. p. 1-5. See http://www.state.vt.us/psb/document/ElectricInitiatives/EEU_Budget_Order.pdf

additional moneys on the programs specified in sub. (2) if the utility otherwise complies with the requirements of this section and s. 16.957 (4).¹⁵¹

(4) ELECTRIC UTILITIES. (a) *Requirement to charge public benefits fees.* Each electric utility, except for a municipal utility, shall charge each customer a public benefits fee in an amount established in rules promulgated by the department under par. (b). An electric utility, except for a municipal utility, shall collect and pay the fees to the department in accordance with the rules promulgated under par. (b). The public benefits fees collected by an electric utility shall be considered trust funds of the department and not income of the electric utility.

(a) *Electric bills.* An electric utility shall include a public benefits fee in the fixed charges for electricity in a customer's bill and shall provide the customer with an annual statement that identifies the annual charges for public benefits fees and describes the programs for which fees are used.

(b) *Rules.* In consultation with the council, the department shall promulgate rules that establish the amount of a public benefits fee under par. (a). Fees established in rules under this paragraph may vary by class of customer, but shall be uniform within each class, and shall satisfy each of the following:

1. The fees may not be based on the kilowatt-hour consumption of electricity by customers.
2. Seventy percent of the total amount of fees charged by an electric provider may be charged to residential customers and 30% of the total may be charged to nonresidential customers.
3. The fees shall allow an electric provider to recover the reasonable and prudent expenses incurred by the electric provider in complying with this section.¹⁵²

Demand Response

At the time of electric system peak, the most expensive and often the most polluting electric sources are called on to maintain reliability. Demand response programs engage customers to give up their right to consume electricity in exchange for some value-based compensation. Under appropriate circumstances, demand response participants enable the system to avoid these high costs and emissions. Furthermore, if demand response can provide a functional equivalent to ten-minute reserves, then costs and pollution associated

¹⁵¹ Wis. Stat. 196.374(2), online at http://folio.legis.state.wi.us/cgi-bin/om_isapi.dll?clientID=34329477&infobase=stats.nfo&softpage=Browse_Frame_Pg

¹⁵² Wis. Stat. 16.957(4). See http://folio.legis.state.wi.us/cgi-bin/om_isapi.dll?clientID=34329477&infobase=stats.nfo&softpage=Browse_Frame_Pg

with maintaining combustion generators on hot stand-by are also avoided. It's important to note, however, that some kinds of demand response can have adverse consequences – for example, if the participant uses polluting on-site generation to replace the electricity it would normally receive from the grid. (See the discussion in Section 16, below, on air emission standards for distributed generation as a response to this concern.)

California

Demand response was designated as a “highest priority” resource in California’s 2003 Energy Action Plan (see “Energy Efficiency Is A Resource” section). In June 2003, the CPUC established specific demand response savings targets for the 3 main electric IOUs:

We hereby adopt the demand response goals enumerated in Table 1 for each IOU. To ensure that these goals are achieved, we direct the respondent IOUs to do the following:

- a. Take all appropriate steps to implement the dynamic pricing tariffs and programs adopted in this proceeding in order to achieve these goals;
- b. Recommend, as a result of monitoring and evaluation efforts, changes to the tariffs and programs adopted here, as well as additional tariffs and programs, to improve the cost-effectiveness of demand response activities;
- c. Include the MW targets for calendar years 2003 through 2007 in their procurement plans to be filed in R.01-10-024. To the extent that this decision is adopted after those plans are filed, the IOUs shall supplement or augment their filings in R.01-10-024 to reflect this requirement, including, in particular: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals;
- d. Work with state agencies and the Independent System Operator (CAISO) to ensure that demand response programs and tariffs are appropriately considered in any resource adequacy or reserve requirements and emergency response activities.¹⁵³

In 2004, when the CPUC adopted the utilities’ long-term procurement plans, new targets were established, reflecting the Energy Action Plan goal of meeting 3% of annual load through demand response:

DR programs can be used to help achieve both system efficiency and reliability goals. There are two general types of DR programs that the IOUs use to reduce demand when energy prices are high or when supplies are tight: ‘price-responsive’ programs (in which customers choose how much load reduction they can provide based on either the

¹⁵³ CPUC Decision 03-06-032. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965-07.htm#P495_139586

electricity price or a per-kW or kWh load reduction incentive), and emergency-triggered programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, usually a commodity discount). Both types of programs motivate customers to reduce their loads in exchange for some type of benefit - such as reduced energy rates, bill credits or exemptions from rotating outages. For purposes of clarification, the term 'demand response program' should be interpreted in this decision to mean 'price-responsive' programs for which the Commission has established specific MW targets to be incorporated into the IOUs' LTPPs.

Price-responsive programs have been the subject of R.02-06-001. D.03-06-032 adopted price-responsive programs, set target goals and directed the utilities on how to integrate DR goals into their procurement plans. As of July 2004, the IOUs have a combined total of **519** MWs enrolled in the authorized programs. D.03-06-032 also adopted DR goals for years 2003 - 2007. The 2005 goal is 3% of 'annual system peak demand,' increasing to 4% in 2006 and 5% in 2007. The adopted goals apply only to 'price-responsive' DR programs. MW savings generated by interruptible programs do not count toward the DR goals articulated in the EAP. Enrollment in interruptible programs is capped at 2,500 MW.

D.03-06-032 also directed the IOUs to include the adopted DR MW goals in their procurement plans, along with documentation of the amount of MWs to be achieved by July of each year, the programs and/or tariffs they will rely on to achieve the MW targets and a contingency plan for covering capacity needs should they fall short of meeting the MW goals.

On October 15, 2004, the IOUs submitted DR program proposals in the DR proceeding for the purpose of meeting their 2005 goals. These proposals include modifications to existing DR programs as well as new programs. If their proposals are approved by the Commission, the IOUs anticipate enrollment of the following amounts of demand response MWs by July 2005:

PG&E: 508 MWs
SCE: 442 MWs
SDG&E: 75 MWs¹⁵⁴

Iowa

476.17 PEAK-LOAD ENERGY CONSERVATION.

1. The board may promulgate rules pursuant to chapter 17A which require or authorize a public utility to establish peak-load management procedures.

2. Rules of the board shall relate to reducing or limiting the peak-load period consumption.

3. In promulgating rules under this section, the board is not bound by decisions, rulings or orders which relate to the definitions of types or classes of customers and which were issued by the Iowa state commerce commission prior to July 1, 1980.¹⁵⁵

¹⁵⁴ CPUC Decision 04-12-048, issued December 2004. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224-03.htm#P447_100069

Require Investment In Energy Efficiency Resources For Transmission Purposes

Transmission system planning and investment are fully regulated activities. Just as with regulated generation and distribution services, policy makers and regulators should require utilities to develop cost-effective efficiency and customer distributed resources (i.e., those located on the customer's side of the meter) before investing in supply-side and transmission resources. Revenues for transmission investment should be collected by the same means (usually customer tariffs), whether the resource originates on the demand side or on the supply side. Transmission use, planning, and investment decisions are usually made by the same entity that manages the wholesale market, or a closely related entity. Transmission tariffs are regulated by the FERC.

California

1001. No . . . electrical corporation . . . shall begin the construction of a . . . line, plant, or system, or of any extension thereof, without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction. . .

1002.3. In considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2, and other demand reduction resources.¹⁵⁶

In order to streamline the transmission review and approval process, the CPUC is in the process of developing a methodology to be used by CAISO that would satisfy the requirements of PUC Code 1001 quoted above. Under the new process, the CAISO would review the CPCN application, while the CPUC would review CAISO's application of the approved methodology rather than review the entire CPCN application. This is being done in investigation I.05-06-041.

Connecticut

Sec. 8. (NEW) (*Effective from passage*)

(a) The Department of Public Utility Control shall, not later than January 1, 2006, establish a program to grant awards to retail end use customers of electric distribution

¹⁵⁵ Iowa Code 476.17, online at <http://coolice.legis.state.ia.us/Cool-ICE/default.asp?category=billinfo&service=IowaCode>

¹⁵⁶ California Public Utilities Code 1002.3. See <http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=01001-02000&file=1001-1013>

companies to fund the capital costs of obtaining projects of customer-side distributed resources, as defined in section 16-1¹⁵⁷ of the general statutes, as amended by this act. Any project shall receive a one-time, nonrecurring award in an amount of not less than two hundred dollars and not more than five hundred dollars per kilowatt of capacity for such customer-side distributed resources, recoverable from federally mandated congestion charges, as defined in section 16-1 of the general statutes, as amended by this act. No such award may be made unless the projected reduction in federally mandated congestion charges attributed to the project for such distributed resources is greater than the amount of the award. The amount of an award shall depend on the impact that the customer-side distributed resources project has on reducing federally mandated congestion charges, as defined in section 16-1 of the general statutes, as amended by this act. Not later than October 1, 2005, the department shall conduct a contested case proceeding, in accordance with chapter 54 of the general statutes, to establish additional standards for the amount of such awards and additional criteria and the process for making such awards.

(b) The Department of Public Utility Control shall, not later than January 1, 2006, establish a program to grant to an electric distribution company a one-time, nonrecurring award to educate, assist and promote investments in customer-side distributed resources developed in such company's service territory, which resources the department determines will reduce federally mandated congestion charges, in accordance with the following: (1) On or before January 1, 2008, two hundred dollars per kilowatt of such resources, (2) on or before January 1, 2009, one hundred fifty dollars per kilowatt of such resources, (3) on or before January 1, 2010, one hundred dollars per kilowatt of such resources, and (4) fifty dollars per kilowatt of such resources thereafter. Payment of the award shall be made at the time each such resource becomes operational. The cost of the award shall be recoverable from federally mandated congestion charges. Revenues from such awards shall not be included in calculating the electric distribution company's earnings for the purpose of determining whether its rates are just and reasonable under sections 16-19, 16-19a and 16-19e of the general statutes.¹⁵⁸

Sec. 35. (NEW) (*Effective from passage*) (a) The Department of Public Utility Control shall, not later than January 1, 2006, establish a program to grant awards from January 1, 2006, to December 31, 2010, of twenty-five dollars per kilowatt-year to electric distribution companies for programs, approved by the department and developed in this state on or after January 1, 2006, of load curtailment, demand reduction and retrofit conservation that reduce federally mandated congested charges for the period from January 1, 2006, to December 31, 2010, or such later date specified by the department.

¹⁵⁷ (40) "Customer-side distributed resources" means (A) the generation of electricity from a unit with a rating of not more than sixty-five megawatts on the premises of a retail end user within the transmission and distribution system including, but not limited to, fuel cells, photovoltaic systems or small wind turbines, or (B) a reduction in the demand for electricity on the premises of a retail end user in the distribution system through methods of conservation and load management, including, but not limited to, peak reduction systems and demand response systems. From the Energy Independence Act, Section 2.16(1)(40). See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

¹⁵⁸ Connecticut Energy Independence Act, Section 8. See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

No such award may be made unless the projected reduction in federally mandated congestion charges attributed to the program is greater than the amount of the award. Such companies' costs associated with establishing a program for which an award is made and the cost of each such award shall be recoverable through the charge for federally mandated congestion charges. Revenues from such awards shall not be included in calculating the electric distribution company's earnings for the purpose of determining whether its rates are just and reasonable under sections 16-19, 16-19a and 16-19e of the general statutes.¹⁵⁹

Indiana

Indiana utilities are required to conduct the following resource assessment in their IRPs:

An electric utility shall provide a description of the utility's electric power resources that must include, at a minimum, the following information . . .

- (6) An analysis of the existing utility transmission system that includes the following:
 - (A) An evaluation of the adequacy to support load growth and long term power purchases and sales.
 - (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses.
 - (C) An evaluation of the potential impact of demand-side resources on the transmission network.
 - (D) An assessment of the transmission component of avoided cost.¹⁶⁰

Maine

Alternatives to construction of transmission line. The Petitioner shall state whether alternatives including conservation, distributed generation or load management to the proposed transmission line project were investigated. If the Petitioner has investigated alternatives, the petition shall include all studies, reports, or other data relied upon in the investigation of such alternatives and shall clearly state the process by which Petitioner decided upon the proposed construction, rebuilding, or relocation project. Specifically, the Petitioner should state the purposes and benefits of the proposed project (such as the promotion of reliability and line loss reduction) and whether cost-benefit analyses have been performed.¹⁶¹

Minnesota

Minnesota statute requires a Certificate of Need for the construction of large energy facilities, including any high-voltage transmission line greater than 200 kilovolts and over 1,500 feet in length, or any transmission line with a capacity of over 100 kilovolts with over ten miles of its length in Minnesota or that crosses a state line. The Certificate rules state:

¹⁵⁹ Ibid., Section 35.

¹⁶⁰ 170 Indiana Administrative Code 4.7.6. See <http://www.in.gov/legislative/iac/T01700/A00040.PDF>

¹⁶¹ MPUC Rules Chapter 330.8.I. See http://mainegov-images.informe.org/mpuc/doing_business/rules/part_3/ch-330.pdf

No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate . . . (2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand . . . (6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation . . . (8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically.¹⁶²

New York

The NYISO has developed rules under which DSM solutions to transmission constraints can be considered on an equal basis with wires solutions in developing the state's Reliability Needs Assessment (RNA):

At the NYISO's request, Market Participants shall provide in accordance with the schedule set forth in the procedures adopted under section 3.0 the data necessary for the development of the RNA. This input will include but not be limited to (1) existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); proposals for merchant transmission facilities (to be provided by merchant developers); generation additions and retirements (to be provided by generator owners and developers); demand response programs (to be provided by demand response providers); and any long-term firm transmission requests made to the Transmission Owners or by municipal electric utilities.¹⁶³

Vermont

Certificate of Public Good Statute. 30 V.S.A. Sec. 248 requires that the Public Service Board issue a Certificate of Public Good before construction can begin on any new electric generation or transmission facility. In addition, the statute states:

Before the public service board issues a certificate of public good as required under subsection (a) of this section, it shall find that the purchase, investment or construction is required to meet the need for present and future demand for service which could not otherwise be provided in a more cost effective manner through energy conservation programs and measures and energy-efficiency and load management measures, including but not limited to those developed pursuant to the provisions of sections 209(d), 218c, and 218(b) of this title.¹⁶⁴

¹⁶² Minnesota Statutes 2005, 216B.243 Subd.3. See <http://www.revisor.leg.state.mn.us/stats/216B/243.html>.

¹⁶³ NYISO FERC electric tariff, volume 1, Attachment Y, online at http://www.nyiso.com/public/webdocs/services/planning/ferc_form_715/part5/nyiso_comp_planning_process_oatt_attach_y.pdf

¹⁶⁴ V.S.A. 30 Sec 248, 4 (A)(b), online at <http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00248>

Distribution Utility Planning. Vermont distribution utilities are required to use least-cost planning to resolve transmission constraints as part of a Distribution Utility Planning (DUP) process. When constrained areas meet certain requirements, distribution utilities must form area-specific collaboratives (ASCs) to consider all solutions and identify and implement the least-cost option:

DUs:[H]ave the responsibility to engage in least-cost transmission and distribution system planning and effectively implement such plans. Utility transmission and distribution planning activities shall be conducted under DUP.¹⁶⁵

. . . Each such ASC will seek to reach agreement, for the area of the T&D system that is the subject of the ASC, on at least the following: identification and screening of traditional T&D options and of DSM and DG options consistent with the Guidelines; an appropriate mix of resources to address the relevant T&D constraint(s); and resource allocations, investment levels, and implementation plans to acquire the agreed-upon mix of resources. . .

. . . It is the Parties' intention that, for areas for which there is an ASC, DUP analysis and implementation, including setting levels of resources to be devoted to acquisition of T&D facilities, DSM or DG, should be determined in accordance with 30 V.S.A. § 218c(a)(1). [Vermont's least-cost planning statute]¹⁶⁶

Transmission Planning. Act 61 of the 2005 Legislature requires utilities to develop 10-year transmission plans, allowing time to identify and implement DSM solutions where appropriate:

Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective nontransmission alternatives to meet reliability needs, wherever feasible. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective nontransmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

¹⁶⁵ MOU, p.2, <http://publicservice.vermont.gov/dockets/6290/6290MOU6%20-%20FINAL.PDF>

¹⁶⁶ MOU, p.4

- (B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;
- (C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;
- (D) estimate the likely costs of these improvements;
- (E) identify potential obstacles to the realization of these improvements; and
- (F) identify the demand or supply parameters that generation, demand response, energy efficiency or other nontransmission strategies would need to address to resolve the reliability deficiencies identified.¹⁶⁷

RATE DESIGN

Good Rate Design Accurately Reflects Long-Run Cost

Good rate design will strongly complement clean energy acquisition policies because it reflects the long-term costs of power resources, including more polluting sources. But, rate design alone is not enough to overcome the well known consumer barriers to investment in energy efficiency. Also, because many environmental costs, such as health and atmospheric damage related to carbon emissions, are not included in electricity or gas prices, the price signal received by customers falls short of reflecting true costs.

Cost-Based, Time-Differentiated Rates and Seasonal Rates

Time-of-use (TOU) and/or real time rates give customers a price signal that encourages efficient use (to the degree that the rates reflect all costs of production, including external ones). There are limitations, however, as the cost of providing TOU signals to customers who do not already have demand meters can overwhelm the system savings expected from voluntary customer response. In addition, absent automated systems that monitor prices and adjust consumption, the relatively small potential savings for (especially) residential and small commercial customers means that these customers are unlikely to consistently respond to price changes unless they are large and sudden. Combining energy efficiency program offerings with inverted block rates and seasonal rates (where costs justify them) is a highly synergistic strategy and a reasonable proxy for TOU rates.

¹⁶⁷ 30 V.S.A. 218 (d). See <http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c>

Seasonally differentiated rates capture the cost of service differences between summer and winter seasons. Many states experience markedly higher demand due to use of air conditioning in the summer months. A higher seasonal summer rate reflects the higher costs of serving customers in the summer months. By delivering this price signal to customers, seasonal rates help to drive investment towards higher-efficiency air conditioning, with marked environmental gains.

Arizona

In a rate case concerning the Arizona Public Service Company (APS), the Arizona Corporation Commission approved a series of changes in rate structures that were intended to render prices more fully reflective of the underlying costs of service, specifically,

APS is also required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand. The plan for the study and analysis of rate design modifications must be presented to the collaborative DSM working group within 90 days, and APS must submit to the Commission the final results as part of its next rate case, or within 15 months of this Decision, whichever is first. APS is required to develop and propose appropriate rate design modifications. . .

. . . We also think it is clear that the traditional demand response programs that define “off-peak” hours as between 9:00 p.m. to 9:00 a.m. are ineffective in creating an incentive to residential ratepayers to shift their electricity consumption to “off peak” hours. Common sense indicates that a substantial number of ratepayers cannot or are not able to take advantage of such programs as 9:00 p.m. is an unrealistic time to commence the “off peak” period because most ratepayers are either asleep or preparing to sleep at that time. Further, the start time begins many hours after the actual peak has subsided. Finally, the inconvenience of a 9:00 p.m. start time assures that the demand response to “off peak” hours and programs is miscalculated. Therefore, in an effort to expedite APS’ addressing demand response programs, we will order APS to file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

We believe that it would be beneficial, perhaps in conjunction with the rate design time-of-use study and the use of “advanced” or “smart” meters, to evaluate and implement programs designed to reduce APS’ summer peak demand. Accordingly, we will encourage submission of such DSM programs.¹⁶⁸

The rates were designed to move toward costs and remove subsidizations, thereby promoting equity among customers. The base rates will also permit cost-based unbundling of distribution and revenue cycle services, including metering, and meter

¹⁶⁸ ACC Docket E-01345A-03-0437, Order of April 7, 2005, pp21-22. See <http://www.cc.state.az.us/utility/electric/APS-FinalOrder.pdf>

reading and billing. The parties believe that this will give appropriate price signals necessary for shopping... Within 180 days APS will submit a study to Staff that examines other ways APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, making those periods more reflective of actual system peak time periods.¹⁶⁹

Among the rate designs were time-of-use, block, and seasonal pricing. With respect to the three-tiered structure for residential users, the ACC said:

We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates thereby lowering peak demand).¹⁷⁰

California

SB1388, passed in 2000, required the CPUC to investigate various approaches to rate design:

393. (a) The commission shall conduct a pilot study of the residential and small commercial customers of each electrical corporation, where the rate level established in subdivision (a) of Section 368 is no longer in effect, to determine the relative value to ratepayers of various information, rate design, and metering innovations for helping residential and small commercial customers better manage their electricity use. The commission shall compare the net benefits, including, but not limited to, all of the following approaches:

(1) The retrofit or replacement of residential and small commercial meters to provide real-time usage information to a standard output interface that is connected to a visual display module within the customer's home or business that presents information, at minimum, on current usage and historic usage. The commission may also test the effects of providing greater amounts of information display capability including, but not limited to, historic usage and estimated aggregated costs for the billing period, associated with the customer's bundled rate structure. The standard output interface of the meter must be multiply accessible to allow the installation by the customer, an electrical corporation, or a registered energy service provider of energy information-based energy management applications.

(2) The replacement of residential and small commercial meters with time-of-use meters that distinguish and measure peak and off-peak energy use. Subject to the approval of the commission, electrical corporations shall offer a rate schedule to customers that differentially price seasonal on-peak, mid-peak, and off-peak energy use that reflects the electrical corporation's actual energy cost. The meters used shall have the same standard usage information output interface as in paragraph (1).

(3) The replacement of residential and small commercial meters with meters that facilitate the offering of hourly real-time pricing.

¹⁶⁹ *Id.* at 31.

¹⁷⁰ *Id.* at 33.

Subject to the approval of the commission, electrical corporations shall offer a rate schedule to customers that prices electricity usage at the electrical corporation's hourly cost. The meters used shall have the same standard usage information output interface as in paragraph (1).

(b) The commission shall ensure that sufficient valid randomized customer use data, normalized for weather, occupancy, energy cost differences and other potentially confounding factors, are collected to respond to, but are not limited to, all of the following questions:

(1) To what extent is the real-time availability of customer usage information to customers sufficient to bring about a significant change in customer energy consumption behavior?

(2) To what extent is the availability of customer usage information to customers sufficient to stimulate innovation in energy information-based energy management applications?

(3) What is the difference in energy consumption behavior between customers that have enhanced access to energy consumption information and those who have time-of-use rates?

(4) Do the differences in usage and net cost savings, if any, between customers who have enhanced energy information and those who have time-of-use rates justify the broader offering of time-of-use metering capability?

(5) What is the difference in energy consumption behavior between customers who consume electricity under hourly real-time pricing and customers who either have enhanced information access or time-of-use pricing? Does the value of these differences justify the broader offering of hourly real-time pricing?

(6) What issues should be addressed prior to systemwide deployment?¹⁷¹

Pursuant to SB 1388, the CPUC in 2002 opened a proceeding to address “policies to develop demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment.”¹⁷² In the course of the proceeding, goals for demand response were established, and pilot programs and tariffs were approved.

Connecticut

Sec.13. (NEW) (*Effective from passage*) (a) Not later than October 1, 2005, each electric distribution company, as defined in section 16-1 of the general statutes, as amended by this act, shall submit an application to the Department of Public Utility Control to (1) on or before January 1, 2007, implement mandatory peak, shoulder and off-peak time of use rates for customers that have a maximum demand of not less than three hundred fifty kilowatts, and (2) on or before June 1, 2006, offer optional interruptible or load response rates for customers that have a maximum demand of not less than three hundred fifty kilowatts and offer optional seasonal and time of use rates for all customers. The application shall propose to establish time of use rates through a procurement plan, revenue neutral adjustments to delivery rates, or both.

¹⁷¹ California Public Utilities Code Section 393. See <http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=391-393>

¹⁷² CPUC Rulemaking 02-06-001. See http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/16311.htm

(b) From March 1, 2006, until December 31, 2006, each electric distribution company shall issue comparative analyses to customers that have a maximum demand of not less than three hundred fifty kilowatts that would demonstrate, at current levels of consumption, the effects of the mandatory time of use rates as specified in subdivision (1) of subsection (a) of this section to be effective beginning January 1, 2007.

(c) Not later than November 1, 2005, each electric distribution company shall submit an application to the Department of Public Utility Control to implement mandatory seasonal rates for all customers beginning April 1, 2007.

(d) From April 1, 2006, until March 31, 2007, each electric distribution company shall issue comparative analyses to all customers that demonstrate, at current levels of consumption, the effects of the mandatory seasonal rates that will be effective beginning April 1, 2007.

(e) The department shall hold a hearing that shall be conducted as a contested case, in accordance with the provisions of chapter 54 of the general statutes, to approve, reject or modify applications submitted pursuant to subsection (a) or (c) of this section. No application for time of use rates shall be approved unless (1) such rates reasonably reflect the cost of service during peak, shoulder, seasonal and off-peak periods, and (2) the costs associated with implementation, the impact on customers and benefits to the utility system justify implementation of such rates, and (3) such rates alter patterns of customer consumption of electricity without undue adverse effect on the customer.

(f) Each electric distribution company shall assist customers to help manage loads and reduce peak consumption through the comprehensive plan developed pursuant to section 16-245m of the general statutes, as amended by this act.

(g) The department shall conduct a contested case, in accordance with chapter 54 of the general statutes, to determine the standards under which, and process by which, a customer, having a maximum demand of three hundred fifty kilowatts or more, may obtain an exemption, until July 1, 2010, from mandatory time of use rates as specified in subdivision (1) of subsection (a) of this section. The department shall issue a decision in the contested case no later than January 1, 2006.¹⁷³

Vermont

In Docket 5426, the Public Service Board approved a new, seasonally differentiated rate structure for Citizens Utilities Company. In so doing, the Board reaffirmed its long-standing principles of rate design:

The critical point is that, to the greatest extent possible, price should approximate marginal cost, since marginal cost reflects the true value to society of allocating its

¹⁷³ Connecticut Energy Independence Act, Section 13. See <http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm>

resources to the particular good demanded. The statutory standard of “just and reasonable” rates is based upon this concept.¹⁷⁴

The Board further refined the point:

A general objective of utility rate design is to promote both fairness and economic efficiency by accurately charging customers for the costs that they cause. Rates, therefore, should be based on costs—specifically, long-run marginal costs.¹⁷⁵

The Board recognized that, given the typically declining long-run marginal cost curves that characterize natural monopoly utility companies, rates based solely on estimates of marginal costs would likely cause serious financial hardship for the company:

A reasonable rate design will, among other things, attempt to reconcile the often competing imperatives of generating revenue requirement and of signaling the economic costs of consumption. The evidence in this docket demonstrates that prices set at marginal costs would be, by themselves, insufficient to cover Citizens’ total embedded costs of service. [The Board approved a simple adder on the energy component of prices to make up the difference.]¹⁷⁶

In response to public concern that the new rate design, based as it was on an analysis of the time-differentiated marginal costs of service, was unfair, the Board stated:

Several ratepayers contend that, if costs are increasing as demand increases, then new customers—those who have recently joined the system—should pay the higher rates. This reveals a critical misunderstanding of what is meant by “the margin.” At any point in time, total demand for electricity equals the sum of all customers’ individual demands for electricity: it has nothing whatsoever to do with customers’ *previous* demand for electricity. The ratepayer who has been served by Citizens for fifteen years has paid for that power in the past; but he has also received the power that he paid for. Thus, his past “accounts are balanced.” As for the future, the longstanding ratepayer is no more entitled to the next kilowatt-hour of energy than is the newly arrived ratepayer: both are equally capable of demanding, or of *not* demanding, additional service. By deciding to consume electricity at a particular moment, each customer, regardless of his pedigree, explicitly allocates some fraction of society’s resources: if both the customer and society are to benefit from that decision, its costs must be accurately reflected in the price. To set some consumers’ prices at marginal cost and others’ at (presumably) less than marginal cost would produce nothing but waste.¹⁷⁷

¹⁷⁴ PSB Docket 5426, Order of July 22, 1992, at 11.

¹⁷⁵ *Id.* at 14.

¹⁷⁶ *Id.* at 21 (footnotes omitted).

¹⁷⁷ *Id.* at 27-28.

Inclining and Declining Block Rates

When rates are “tiered”, or divided into blocks, different blocks can be priced to induce different customer behavior. An “inclining block” rate gives customers an incentive to reduce consumption by pricing the first tier of kWh at the lowest rate and assigning higher rates to subsequent tiers.

Arizona

In a recent rate case, the Arizona Corporation Commission required revisions to existing tariffs:

The parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.¹⁷⁸

Avoid Bad Rate Design

Higher fixed charges with lower usage (unit) charges have been advanced recently by several utilities. This rate design is attractive to utilities because it creates a larger assured revenue stream and reduces the risk of lower revenues when lower usage occurs *for whatever reason*. The downside is twofold: the design fails to reflect the long-term marginal costs of providing the product, and it removes the price signal to customers to consume electricity and gas efficiently. Moreover, it raises bills for low-volume consumers (i.e., those who consume less than the average) and lowers bills for high-usage customers, including those with high air conditioning usage, who are helping to drive high-cost system peaks. A utility’s interest in avoiding risks of revenue loss due to greater use of efficiency is much better addressed through revenue/sales decoupling, described above.

¹⁷⁸ ACC Docket E-01345A-03-0437, Order of April 7, 2005, at 14-16.

Similarly, use of “declining block” rates should be avoided. These rates assign the highest per kWh charge to the first “block” of kWh used by a customer, and assigns lower rates to subsequent blocks. While declining block rates are attractive to utilities, there are better methods of assuring utility revenues, as mentioned above, that do not interfere with customers’ incentives to conserve energy.

Arizona

In a recent rate case, the Arizona Public Service Company and several other parties submitted a settlement to the Arizona Corporation Commission that, among other things, called for the implementation of a “power supply adjustor” (PSA) that would allow for the immediate pass through to customers of changes in fuel and purchased powers costs. This mechanism is generically referred to as a “fuel adjustment clause” (FAC). The ACC considered the pros and cons of the adjustor and decided to approve a significantly modified version of it. Their discussion identifies some of the problems with FACs:

Advantages: 1) the reporting requirements and forecasts facilitate utility planning and Staff overview of costs; 2) an adjustor that works correctly, over time, reduces the volatility of a utility’s earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates; 3) adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included; 4) adjustors can help reduce the frequency of rate cases; 5) regulatory lag between the incurrence of an expense and its recovery is reduced and generational inequities are also reduced.

Disadvantages: 1) adjustors can reduce incentives to minimize costs; 2) an adjustor that includes fuel or purchased power costs potentially biases capital investment decisions towards those with lower capital costs and higher fuel costs; 3) adjustors create another layer of regulation to rate cases, increasing the cost of regulation to the utility, its customers, and to the Commission; 4) an adjustor can shift a disproportionate proportion of the risk of forced outages and systems operations from shareholders to ratepayers; 5) adjustors result in piecemeal regulation – an adjustor reflects an increase in one expense but ignores offsetting savings in other costs; 6) adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers; 7) proper monitoring of adjustor filings and audits require the devotion of significant Staff resources; and 8) rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Although we recently approved the concept of a PSA, we are concerned about the PSA as proposed in the Settlement Agreement. The benefits of this PSA are that over time, the utility’s earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers. Further, as part of the negotiations, the parties were able to agree on a lower overall revenue increase because a PSA was to be implemented.

AECC pointed out that if an adjustor remains in effect for long enough, it becomes a credit, and therefore, the PSA should remain in effect for five years.

The disadvantages are real and significant – from a customer standpoint, adjustors are difficult to understand and they can cause annual price increases. From a regulatory standpoint, they require significant Commission staff resources to properly monitor filings, costs, and compliance and to respond to consumer inquiries and complaints. The most significant change that will occur with a PSA is the shifting of the risk that fuel costs will increase above the base rates established in the Settlement Agreement. Currently, if fuel costs or any other costs rise above the level embedded in the existing rate structure, the company’s shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS’ “mix” of fuel will change as growth occurs. That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS’ other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a high cost fuel. . . ¹⁷⁹

. . .38. We agree that the use of an adjustor when fuel costs are volatile prevents a utility’s financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS’ rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS’ fixed costs will increase in the same proportion as its fuel costs.

According to the late- filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of \$100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach \$100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between

¹⁷⁹ ACC Docket E-01345A-03-0437, Order of April 7, 2005, at 14-16. One very critical shortcoming of FACs was overlooked by the ACC, namely, the effect that the shifting of fuel-price risk to consumers has on the long-term resource acquisition strategy of the company. If the company is no longer bearing fuel-price risk, then it no longer has an incentive to invest in resources that will mitigate that risk, e.g., renewables, efficiency, and other non-fossil-fuel fired technologies. While shifting that risk to consumers should indeed reduce the company’s required rate of return, it is doubtful that the consequent reduction in rates fully offsets the new costs that bearing fuel-price-risk now imposes on customers. The primary reason for this is that the company is far better able to manage the aggregate fuel-price risk of its customers than they are as individuals.

\$50 million and \$100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

39. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.¹⁸⁰

Maine

In 1994, the Maine Public Utilities Commission reviewed Central Maine Power Company's long-term resource acquisition plans and the relationship of retail rate designs to them. The PUC's order describes how rate structures should reflect the long-term resource costs associated with consumption:

When, instead, we review a utility's long-term resource plans, projected cost structures, and rate design proposals, our perspective is largely forward-looking and uncertain. We ask how a utility can best meet its customers' needs over the long-term planning period? What are the most likely costs? How should those costs be assigned to each class of customer? How should the costs be reflected in the pricing details of the specific rate structure offered? To answer these questions, we must look into an uncertain future, choose among the competing planning strategies on the basis of educated judgments about future supply and demand conditions, and decide how those choices can best be reflected in the design of rates. . . .

. . . [W]e turn to the single, key question on which much of the argument in the case has centered: Should public policy allow or encourage CMP to promote load growth through a broad adoption of a rate structure known as "declining block" rates? . . . Since 1986, CMP's rate for most of its residential customers, known as Rate A, has had an "inclining block" structure, in which the price per kWh for the first 400 kWh per month is 20 percent lower than the price for usage above 400 kWh per month. . . .

In this case, CMP has asked us to approve the concept of replacing the inclining block structure of residential Rate A, and the flat rate energy charge of other residential and many commercial customers, with a declining block rate, so that the "tail block" monthly consumption above certain thresholds would be priced at a much lower rate. According to CMP, the purpose of this proposal is to improve economic efficiency, to make the price of electricity more competitive with oil for space or water heating, and implicitly, to encourage a general increase in the usage of electricity. In reviewing the evidence and argument developed in this case of the past year, we find that CMP has not made a convincing case for such a substantial revision to our long-standing rate design policies. . . .

Even if it could be shown that a change to declining block rates would be likely to yield at least a short-run revenue increase, we are not persuaded that such a move would be in the public interest. CMP argues that its current cost situation, in which marginal costs are well below average costs, will persist indefinitely, as a result of future cost-saving technologies and competitive pressures, and that rates should therefore be designed to encourage load growth. The record provides little support for such untempered

¹⁸⁰ *Id.*, p. 38

optimism. Instead, the evidence shows that current cost relationships result to a significant degree from a temporary excess of “base-loaded” resources and expensive long-term power purchases. A strategy of encouraging marginal usage through broad adoption of declining rates would run a substantial risk of higher costs and rates, as current excesses diminish and new resources are needed. . . .

We find that rates should continue to reflect the long-run marginal costs of service and the differences in costs between seasons and among times of day. . . .¹⁸¹

Green Pricing

Green pricing is a generic term for the offer of electricity generated from clean, environmentally-preferred sources such as solar, wind, geothermal, and some types of biomass and hydro energy resources. Consumers who choose to purchase this product pay a small premium for the green electricity. The premium directly supports the development of green resources. Green pricing initiatives have met with some (limited) success. Green pricing elevates customer awareness but can also implicitly send the inaccurate message that clean energy is an expensive luxury. Companies must also have a plan to provide sufficient electricity from qualifying clean energy sources to match the amount they are selling to green pricing subscribers.

Colorado tbd

New Mexico

In December 2002, the New Mexico Public Regulation Commission adopted a rule requiring utilities to meet a specified portion of their aggregate loads with electricity produced by renewable energy facilities (as defined in the statute). Also in that rule, the Commission required all utilities to offer optional renewable energy products, that will allow customers to purchase “green” energy in excess of that provided pursuant to the RPS.:

17.9.572.15 VOLUNTARY RENEWABLE TARIFFS:

A. Each public utility shall offer a voluntary renewable energy tariff for those customers who want the option to purchase additional renewable energy.

B. The voluntary renewable tariff may also include provisions to enable consumers to purchase renewable energy within certain energy blocks and by source of renewable energy. Additionally, each public utility must develop an educational program on the benefits and availability of its voluntary renewable energy program. The tariff, along with the details of the consumer education program, shall be on file with the commission.¹⁸²

¹⁸¹ *Re Central Maine Power Company*, 150 P.U.R.4th 229 (Maine PUC 1994).

¹⁸² 17.9.572.15 NMAC - Rp, 17.9.572.10 NMAC, 1-14-05.

New Mexico is not alone in this green pricing requirement. Five other states—Iowa, Minnesota, Montana, Oregon, and Washington—have also required, by statute, their utilities to offer such voluntary programs.

Washington

Washington's green pricing requirement went into effect on January 1, 2002.

RCW 19.29A.090

Voluntary option to purchase qualified alternative energy resources — Rates, terms, and conditions — Reports.

- (1) Beginning January 1, 2002, each electric utility must provide to its retail electricity customers a voluntary option to purchase qualified alternative energy resources in accordance with this section.
- (2) Each electric utility must include with its retail electric customer's regular billing statements, at least quarterly, a voluntary option to purchase qualified alternative energy resources. The option may allow customers to purchase qualified alternative energy resources at fixed or variable rates and for fixed or variable periods of time, including but not limited to monthly, quarterly, or annual purchase agreements. A utility may provide qualified alternative energy resource options through either: (a) Resources it owns or contracts for; or (b) the purchase of credits issued by a clearinghouse or other system by which the utility may secure, for trade or other consideration, verifiable evidence that a second party has a qualified alternative energy resource and that the second party agrees to transfer such evidence exclusively to the benefit of the utility.
- (3) For the purposes of this section, a "qualified alternative energy resource" means the electricity produced from generation facilities that are fueled by: (a) Wind; (b) solar energy; (c) geothermal energy; (d) landfill gas; (e) wave or tidal action; (f) gas produced during the treatment of wastewater; (g) qualified hydropower; or (h) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic.
- (4) For the purposes of this section, "qualified hydropower" means the energy produced either: (a) As a result of modernizations or upgrades made after June 1, 1998, to hydropower facilities operating on May 8, 2001, that have been demonstrated to reduce the mortality of anadromous fish; or (b) by run of the river or run of the canal hydropower facilities that are not responsible for obstructing the passage of anadromous fish.
- (5) The rates, terms, conditions, and customer notification of each utility's option or options offered in accordance with this section must be approved by the governing body of the consumer-owned utility or by the commission for investor-owned utilities. All costs and benefits associated with any option offered by an electric utility under this section must be allocated to the customers who voluntarily choose that option and may

not be shifted to any customers who have not chosen such option. Utilities may pursue known, lawful aggregated purchasing of qualified alternative energy resources with other utilities to the extent aggregated purchasing can reduce the unit cost of qualified alternative energy resources, and are encouraged to investigate opportunities to aggregate the purchase of alternative energy resources by their customers. Aggregated purchases by investor-owned utilities must comply with any applicable rules or policies adopted by the commission related to least-cost planning or the acquisition of renewable resources.

(6) Each consumer-owned utility must report annually to the department and each investor-owned utility must report annually to the commission beginning October 1, 2002, until October 1, 2012, describing the option or options it is offering its customers under the requirements of this section, the rate of customer participation, the amount of qualified alternative energy resources purchased by customers, the amount of utility investments in qualified alternative energy resources, and the results of pursuing aggregated purchasing opportunities. The department and the commission together shall report annually to the legislature, beginning December 1, 2002, until December 1, 2012, with the results of the utility reports.¹⁸³

FINAL WORDS

A common characteristic of states with successful clean energy policies is the presence of a champion—a governor, a legislative leader, a utility commissioner – who has a sustained interest in making clean energy happen and will advocate effectively for it. Another characteristic is a long-term commitment to some degree of energy resource planning.

When working to establish successful clean energy policies, policy makers need to be mindful of the distinction between the initial policy decisions and the myriad follow-up decisions required to actually secure successful long-term development. A state may require electric utilities to collect a systems benefit charge or to file an integrated resource plan that includes all cost-effective energy efficiency, but many crucial steps remain between the policy requirement and the actual deployment of energy efficiency, renewable power, and other clean power resources. Follow through, continued advocacy and consistency matter.

WHERE YOU CAN LEARN MORE: www.raponline.org

RAP's website has papers with in-depth discussions of most of the clean energy policies discussed here. Look for the following topics:

Portfolio Management: Discusses strategies for public investment in reliable, low-cost and efficient resources.

NEDRI: The New England Demand Side Initiative Final Report, June 2003, describes in detail the options for efficiency, renewable resources and distributed generation in wholesale markets.

¹⁸³[2002 c 285 § 6; 2002 c 191 § 1; 2001 c 214 § 28.

Distributed Generation: This series of seven papers covers everything from rate design and financial incentives to a Model Emissions Rule.

Decoupling: Profits and Progress discusses the need for correcting regulatory disincentives to efficiency investment.

Issueletters: Issuesletter: Electric Industry Restructuring and the Environment, August 1999.