The Role of Rate Increases

Without going into the particular mechanisms by which rates can and will rise, it is important to understand the role of rates in the overall financial picture of retail electricity providers. Among other objectives, retail rates must cover operating costs and maintain the financial integrity of utilities in order for utilities to pursue needed investments, the benefits of which ultimately flow to ratepayers and society at large. Properly designed and implemented, rates can also help utilities and customers to improve resource allocation. Evolution in rate design to better improve the connection between wholesale market and retail prices can reduce operating costs and rationalize investments in generating capacity and end-use efficiency or demand flexibility. The fact that rates are rising should not divert attention from innovative rate structures that can have benefits for both utilities and their customers.

The relationship between operating expenses, financial condition, the cost of capital, and the ability to pursue investments is complex insofar as it represents a blend of current circumstances and future expectations regarding how rapidly and accurately rates can change to enable utilities to fully recover costs, including an adequate return on capital. One of the important aspects of adequate rates and viable rate adjustment mechanisms is that they can and should lower investment costs of utilities. This means that investments undertaken to enhance reliability, improve deliverability and power quality, expand generation capacity, or improve environmental performance can be made at reasonable costs—and thus help to mitigate future rate increases. In contrast, rates that compromise current operating cost recovery without adequate prospects of adjustments will raise investment costs and discourage investment that can yield long-term benefits.

The Long-Term Benefits of Appropriate Rate Treatment

The previous chapters have detailed the potential benefits that arise from expanding investments in utility infrastructure, and also outlined the current challenges that utilities face in raising external funds to increase investment. This tension between near-term rate increases and the ability of utilities to invest in infrastructure to help alleviate those cost increases in the long term is inherent in regulation. However, it is worthwhile to point out that substantial benefits would occur if utilities are able to make the requisite investments in infrastructure improvements. These benefits include:

- **Long-term reductions in operating costs,** which would accompany investments in economic baseload capacity, expanded transmission capability, and new distribution-level investments, which could enable consumers to manage their energy costs more efficiently.
- **Enhancements of reliability and power quality,** which would reduce the costs of power interruptions and promote productivity based on the continuing penetration of digital equipment that requires highly reliable service.
- **Improvements in competitive power markets,** which would occur as transmission investments enable more fluid and liquid wholesale power markets over broader geographic areas.
- **Cleaner generation** from advanced coal, nuclear, and renewable power generation sources, which also would reduce the costs of meeting potential future greenhouse gas mandates.

- **Increased customer choice and control over energy use**, which would arise from retail distribution investments that enable innovative rate designs, distributed generation, and a host of technologies that rely on enhanced connection between retail customers and wholesale power markets.

These are examples of the anticipated benefits from utility investments that could be imperiled by a backlash against rising prices, which could lead to inadequate rate adjustments and an eroded ability of utilities to pursue these improvements. While the near-term choices are often stark and unpleasant, the benefits from prudent utility investment have not diminished in this era of high fuel costs and rising costs of capital. On the contrary, the costs of inaction and capital investment atrophy are large and growing.

Household Power Use: Past, Present, and Future

Figure A-1 shows how the typical household's consumption of electricity has evolved over the last 25 years. In 1978, more than 15 percent of a typical household's electricity consumption was devoted to space heating. Another 12 percent was devoted to water heating. By 2003, average household electricity consumption increased 21 percent, from 1.07 kilowatt (kW) per hour to 1.30 kW per hour. The percentage of electricity devoted to space heating and water heating declined, while the portion of electricity devoted to appliances and air conditioning increased. These changes are the result of several factors, with the most notable being the growth of personal digital appliances, such as computers, along with increased market penetration of air conditioning and many other electric appliances.

Figure A-1 also shows projected household energy use in 2030. Average household consumption is expected to increase by more than 11 percent, to 1.45 kW per hour. This increase will be entirely driven by appliance-related consumption, largely reflecting the increased penetration of computers and other digital technologies. The amount of electricity needed to heat water and living space, along with electricity needed for refrigeration and clothes washing, is expected to decline slightly as these technologies become more efficient over time.

Greater demand for electric power, however, does not translate directly into higher household expenditures. To illustrate this point, Table A-1 and Figure A-2 show that the average American household's total spending on electricity has fallen steadily over time. Table A-1 illustrates that average annual expenditures on electricity fell from 2.9 percent of total expenditures in 1984 to 2.5 percent of consumer expenditures in 2004.

Table A-1 also shows that this rate of spending has been lower than that of the other major categories of consumer expenditures. Spending on housing, health care, and insurance premiums all more than doubled over the 1984 to 2004 time period, while nominal spending on electricity increased by 69 percent. Since the price of all goods rose by more than 82 percent during this period, inflation-adjusted household spending on electric power *declined.*

Figure A-1
Electricity Use in the Typical U.S. Home – Yesterday, Today, and Tomorrow

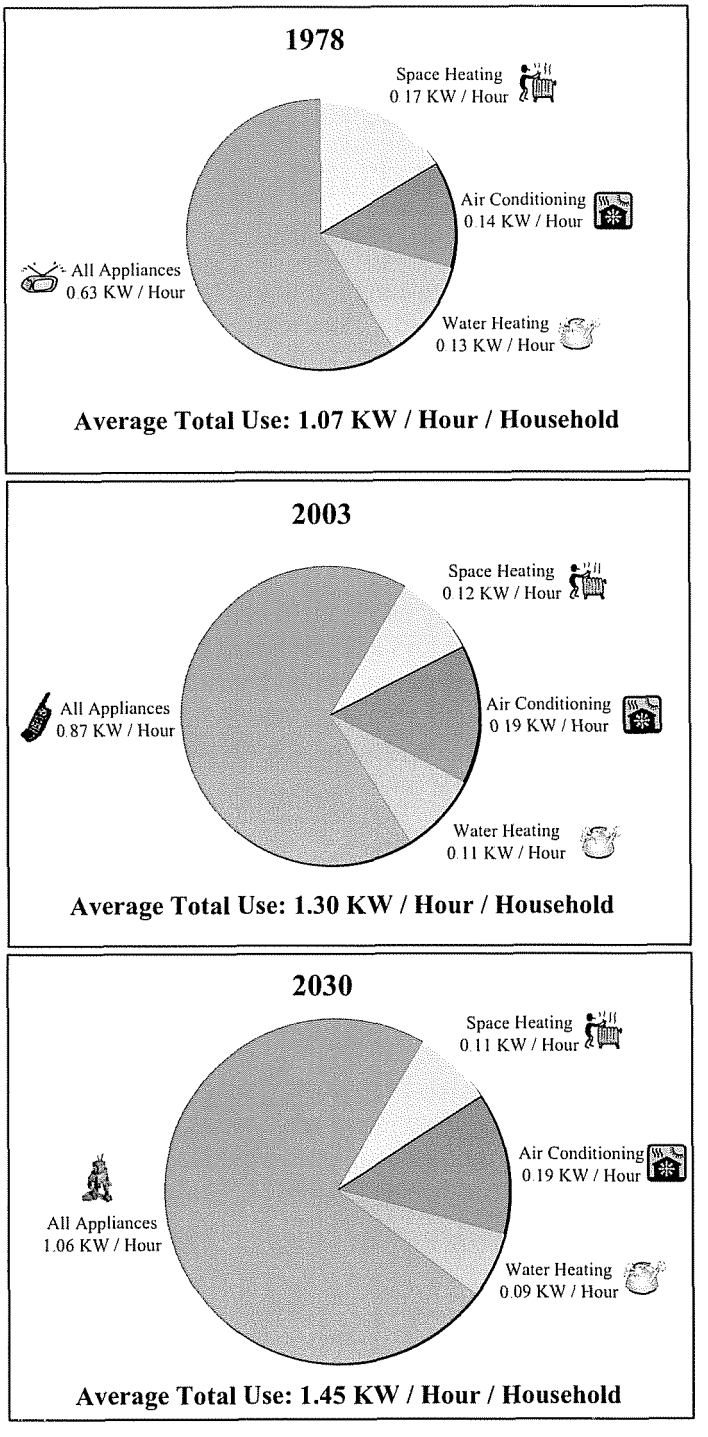
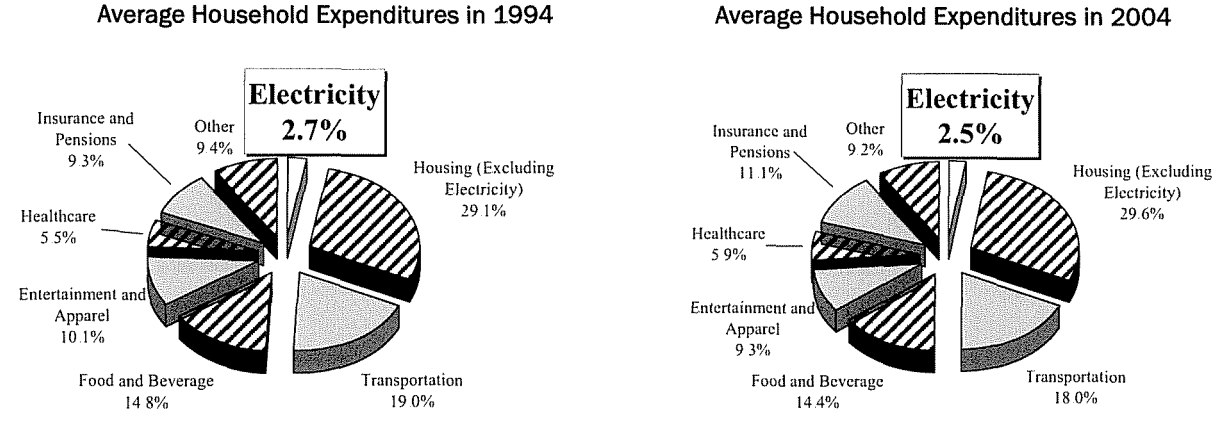


Table A-1: Comparison of Average Annual Consumer Expenditures

Category	1984	1994	2004	1984 - 2004 Percentage Change
Total Expenditures	$21,975	$31,731	$43,395	97%
Electricity	$629	$861	$1,064	69%
(fraction of total)	*2.9%*	*2.7%*	*2.5%*	
Housing (Excluding Electricity)	$6,045	$9,245	$12,854	113%
(fraction of total)	*27.5%*	*29.1%*	*29.6%*	
Transportation	$4,304	$6,044	$7,801	81%
(fraction of total)	*19.6%*	*19.0%*	*18.0%*	
Food and Beverage	$3,565	$4,689	$6,240	75%
(fraction of total)	*16.2%*	*14.8%*	*14.4%*	
Entertainment and Apparel	$2,374	$3,211	$4,034	70%
(fraction of total)	*10.8%*	*10.1%*	*9.3%*	
Healthcare	$1,049	$1,755	$2,574	145%
(fraction of total)	*4.8%*	*5.5%*	*5.9%*	
Insurance and Pensions	$1,897	$2,938	$4,823	154%
(fraction of total)	*8.6%*	*9.3%*	*11.1%*	

Source:
Bureau of Labor Statistics.

Figure A-2
At Today's Electricity Prices, Electricity's Share of the Household Budget Is Smaller Than It Was 10 Years Ago.



Source: Bureau of Labor Statistics

Impacts of Price Increases on Electricity Demand Growth Forecasts

Figure B-1 shows key inputs and outputs for EIA's most recent long-term forecast. Retail electricity prices (in real cents/kWh) and costs for delivered fuel (in real $/MMBtu) are measured on the left axis. Projected annual consumption (in billion kWh) is measured on the right axis. The forecast includes actual data for 2003 and 2004, while data for 2005 reflect the best estimates given the data available at the time of the analysis.

Figure B-1 shows that significant increases in retail electricity prices in 2005 (that are now confirmed) were included in EIA's estimate. EIA shows an approximately 0.75 cent/kWh (+10 percent) real price increase in 2005, which is quite a significant one-year event. Also visible from the chart is a small flattening in the slope of the demand curve between 2005 and 2006, indicating that some degree of price response of demand is included in the forecast.

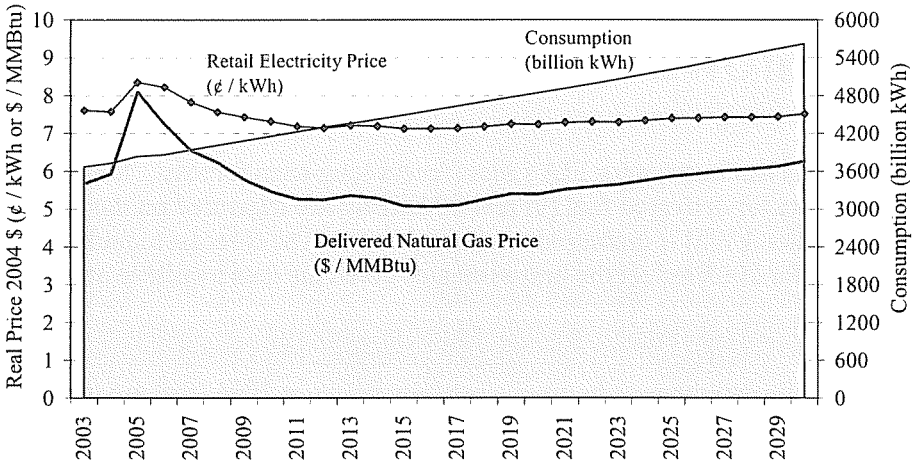
Thus, the historical calibration included in EIA's model shows sensitivity to recent spikes in retail prices. Following this one-year price increase, however, EIA projects significant declines in the real price of electricity, with a flattening in later years. This steady-to-declining trend in real electricity prices in 2006 and beyond closely tracks historical trends, and accordingly, demand follows a steady upward trajectory.[120]

In the context of EIA's modeling framework, the fall in prices is likely due to several factors. First and most important, both the rise and fall in electricity prices correspond closely with projected fuel costs. Second, generating capacity additions underlying EIA's forecast are not dramatic in the near term, as EIA projects about 50 GW of additions over the period through 2014, well below NERC's forecast of 86 GW. Thus, the rate base for generation is not growing at a significant pace in the near term under EIA's projections. While we have no reason to doubt the internal consistency of EIA's projections and the underlying data, this discussion suggests that such assumptions will impact the projection of demand growth. In EIA's projections, fuel prices (notably natural gas) drop rapidly in price from a 2005 high, bringing electricity prices down with them. With lower real energy prices, EIA is justified in projecting continued growth in the

[120] EIA's most recent *Short Term Energy Outlook* (May 2006) forecasts retail electricity prices to be essentially flat in real terms from 2006 to 2008.

demand for electric power. However, even with these relatively optimistic assumptions, EIA's demand forecast is below NERC's latest base case forecast.[121]

Figure B-1
EIA AEO 2006 Electricity Price Forecast and Other Inputs



Source
EIA Annual Energy Outlook 2006

To gain a better sense of the potential magnitude of the price response of demand, we have conducted a simple sensitivity calculation of possible price effects on EIA's projections. EIA's electricity forecasting model includes a constant price elasticity for residential and commercial energy usage. For residential electricity use, the elasticity used is -0.15. In other words, for a 10-percent increase in electricity prices, residential demand for electricity should fall by 1.5 percent. The price elasticity reported for the commercial sector is -0.25.[122] Thus, EIA assumes that commercial users of electricity are more capable of reducing demand in the face of swings in electricity prices. The demand responses to price changes are phased in over a three-year period. Specifically, 50 percent of the demand impact occurs in the year of the price change, 35 percent of the impact occurs one year later, and 15 percent of the impact occurs two years later.

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[121] Other publicly available sources of demand forecasts do not provide as much detail about electricity price assumptions. Global Insight, Inc.'s (GII) *Summer 2005 U.S. Energy Outlook* (published in August 2005) provides the most comprehensive forecast of both electricity prices and demand outside of EIA. Some of GII's results are described in EIA's *Annual Energy Outlook 2006* forecast comparisons and provide examples of the relationship between price and demand forecasts (http://www.eia.doe.gov/oiaf/aeo/pdf/forecast.pdf). For example, GII's forecast of real electricity prices by 2015 is 0.5 cents/kWh higher than that of EIA's. GII's electricity sale predictions are 61 billion kWh lower than EIA's for the same year. While these snapshots do not provide sufficient detail to determine if the full difference in demand flows from price assumptions, they provide more anecdotal evidence that increases in retail price assumptions will impact the path of demand forecasts.

[122] Assumptions to the *Annual Energy Outlook 2006*, Residential and Commercial demand modules.

EIA's forecasts of short-term price elasticities are in line with the very large published literature on electric price impacts, but these elasticities are definitely short-term rather than long-term values. Electric demand analysts long ago established that the effects of a real price increase are spread over approximately the seven years following an increase. The total effect of the increase (*i.e.*, the long-term elasticity) is generally regarded to be on the order of -1.0, seven times as large as EIA's short-term value. Under EIA's framework, long-term elasticities are incorporated implicitly through its bottom-up approach of modeling. That is, consumers will shift their expenditures away from products that are associated with higher input prices in the long run.

As discussed in this report, a variety of factors could lead to higher retail electricity rates. One example is that natural gas prices might remain at higher levels than projected. As shown in Chapter 2, EIA's own *Short Term Energy Outlook* now projects higher natural gas prices in the next two years than what was forecast in EIA's *Annual Energy Outlook 2006*. A wide variety of factors could result in deviations from the latter forecast, all of which could impact both price and consequently demand.

Our sensitivity analysis simply calculates the effect of a sustained real power price increase with the same short-run EIA elasticity effects over a three-year lag. In particular, real prices are assumed to increase 10 percent between 2005 and 2006, and then no change in real price is forecasted through 2014. Demand is then adjusted based upon the short-run elasticity factors from EIA and the difference in price from the underlying forecast in a given year. For example, in 2005, residential real prices were 9.81 cents per kWh, and EIA projects the price to fall approximately three percent by 2006 to 9.51 cents per kWh. In our sensitivity calculation, the 2005 rate is increased by 10 percent to reach a level of 10.79 cents per kWh. Thus, prices are 13 percent higher in 2006 than projected by EIA: 10 percent flowing from the assumed increase in rates and three percent flowing from the removal of EIA's assumed drop in price. Since real prices are 13 percent higher than modeled in 2006, the total demand reduction is about two percent given an elasticity of -0.15 (.13 x -0.15 = -0.02). Fifty percent of the demand reduction is assumed to occur in 2006, 35 percent of it is assumed to occur in 2007, and the remaining 15 percent of it occurs in 2008, following EIA's structure.

This calculation is preliminary and illustrative, but it highlights the linkage between prices and forecast demand that can have a substantial impact on the amount and timing of new generating capacity needed. In addition, demand is likely to be moderated through an expansion of demand-side management and demand-response programs adopted by utilities.

Discussion of Historical Transmission Investment Trends

There are several plausible reasons why transmission investment declined over the 1975 to 1999 period. One reason is that utilities were building less generation during this period because many companies had ample reserve margins and needed to "work off" the excess generation constructed during the 1970s. These large reserve margins tended to persist longer than expected because electricity growth slowed at this time. In addition, to the extent new generation was being built, it tended to be smaller than the large baseload plants that were built during the 1960s and 1970s. Moreover, the gas-fired units that became popular starting in the mid-1980s could be added closer to loads and therefore had less need for incremental transmission than coal-fired or nuclear units. One industry expert suggests that less transmission needed to be built because the industry became more knowledgeable and skilled at getting more out of a given set of assets through better system monitoring, pre-specified remedial actions to deal with operating contingencies, and automatic protection measures.[123] The industry's financial condition also worsened starting in the mid-1970s, and it is possible that construction budgets for transmission became a logical target for reductions. It also is possible that industry management became more reluctant to invest in transmission because of uncertainty over the rules governing cost recovery and use of the asset as the transition to a more competitive wholesale market started. In summary, less transmission may have been built between 1975 and 1999 because: (1) it wasn't physically needed, and (2) utilities were less financially capable of making large investments in transmission.

While significant research would be needed to definitively prove or disprove these hypotheses, a review of the data suggests that there is support for both of these primary reasons; *i.e.*, less new transmission was needed and utilities were less financially capable of making such investments. A review of the nationwide reserve margin for IOUs shows that it jumped from 27.2 percent in 1974 to 34.3 percent in 1975, and stayed above 30 percent through 1987. Indeed, in one year (1982) the reserve margin actually exceeded 40 percent. Reserve margins for the period 1974 to 1996 are shown in Table C-1.

A review of the average plant size of new generating plants brought into service starting in 1980 confirms the hypothesis that new plants started to get smaller at this time. Figure C-1 shows that the average size of all new plants brought into service during the 1980s fell significantly throughout that decade and then rebounded somewhat in the 1990s. It is interesting that the sharp upturn in average plant size that occurs in the late 1990s coincides almost perfectly with the increase in transmission investment.

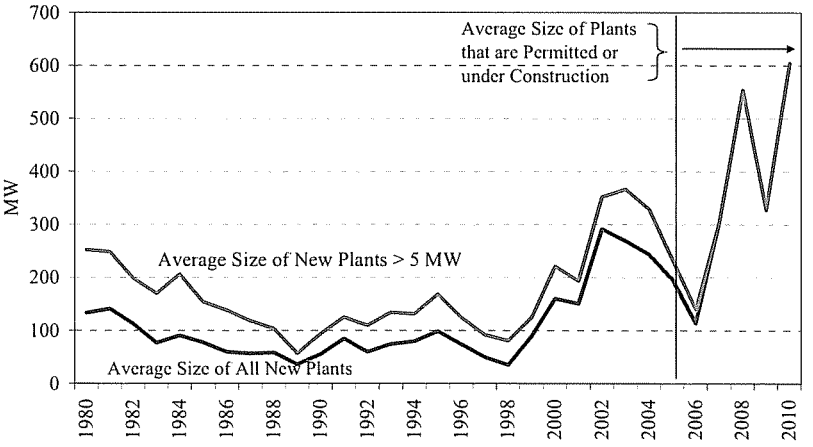
[123] Phone conversation between Greg Basheda and Marty Baughman, May 4, 2006.

Table C-1 Reserve Margins for IOUs (1974 to 1996)

Year	Reserve Margin%	Year	Reserve Margin%
1974	27.2	1986	32.8
1975	34.3	1987	30.6
1976	34.5	1988	25.0
1977	30.2	1989	28.6
1978	33.7	1990	25.6
1979	36.9	1991	25.3
1980	30.7	1992	26.7
1981	33.6	1993	20.7
1982	41.3	1994	20.1
1983	33.3	1995	15.2
1984	34.0	1996	17.6
1985	35.2		

Source: EEI, as reported in Leonard S., Andrew S. and Robert S. Hyman, *America's Electric Utilities: Past, Present and Future*, Eighth Edition, Public Utilities Reports, August 2005.

Figure C-1
Average Size of New Generating Plants



Source: Energy Velocity

The financial aspect of this analysis is more complicated, because one would have to construct a "but for" scenario of how much utilities would have invested in transmission under better financial conditions. It is clear, however, that the 1975 to 1985 period was one of financial stress for the electric power industry. As

Hyman et al. observe, the industry's market-to-book ratio, as calculated by Moody's, fell below 100 in 1974 and stayed below 100 until 1985 (when it reached 101).[124] Thus, returns during this time were insufficient to meet James Bonbright's standard of profitability; *i.e.*, returns should permit the utility to issue more stock at prices not less than the per-share book value of the old stock.[125] The 1975 to 1985 period clearly was not a good time for the industry to raise significant amounts of capital.

These findings are important but not conclusive, because if the decline in transmission investment was due primarily to ample generation and transmission capacity, changes in the size of new generators, and the location of new generation investment, then the decline was likely to have little, if any, impact on transmission reliability. However, if the decline also was driven by financial considerations, this suggests that the decline could have adversely affected reliability as cash-strapped utilities decided to defer or scuttle transmission investments. The first hypothesis seems to be the more likely of the two simply because there is no evidence that the U.S. transmission system was inadequate, in terms of enabling reliable service, in the last 25 years. None of the major blackouts that have occurred over the past 25 years has been found to be caused by inadequate transmission capacity. Most have resulted from some combination of operator error and inadequate maintenance practices (*e.g.*, tree trimming). This is not to say that the transmission grid has not become more "stressed" or "congested" over time; it has, as discussed in Chapter 5. But the system has continued to meet long-standing industry reliability standards, which NERC and the Regional Reliability Councils define in terms of minimizing the probability of incurring an involuntary outage or loss of load due to a failure of the bulk power system.

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[124] Leonard S., Andrew S. and Robert S. Hyman, *America's Electric Utilities: Past, Present and Future*, Eighth Edition, Public Utilities Reports, August 2005, pp. 171, 189.

[125] *Id.*, pp. 170-171.

Decoupling Utility Profits From Sales

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The Regulatory Assistance Project

- RAP is a non-profit organization, formed in 1992, that provides workshops and education assistance to state government officials on electric utility regulation. RAP is funded by the Energy Foundation, US DOE and US EPA.
- RAP Mission:

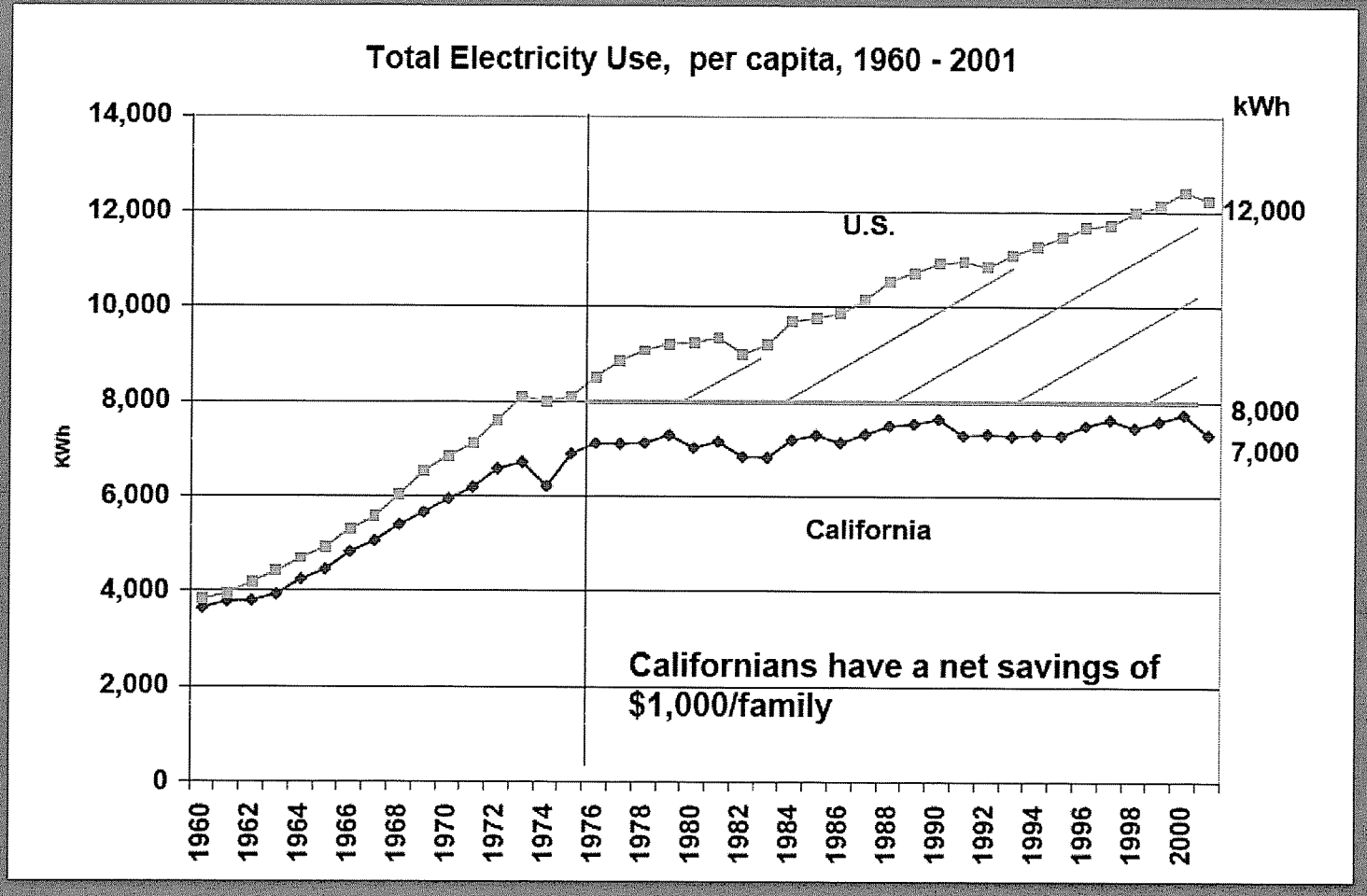
  RAP is committed to fostering regulatory policies for the electric industry that encourage economic efficiency, protect environmental quality, assure system reliability, and allocate system benefits fairly to all customers

- RAP is an independent organization dedicated to the public interest and does not represent or consult for private interests or utilities

Attributes of Energy Efficiency

- More than 20 years of experience demonstrates energy efficiency is a very large and low cost resource.
- Energy efficiency is clean, cheap, and fast.
  - Reduces market prices for gas and electricity,
  - Reduces transmission congestion,
  - Reduces air and water pollution and
  - Improves reliability
- Energy efficiency is good for all except utilities

Value of Efficiency: California Experience



Source: Commissioner Art Rosenfeld, CEC

Traditional Regulation: The Throughput Problem

- Traditional ROR regulation sets *prices*, not *revenues*
  - The revenue requirement is simply an estimate of the total cost to provide service
- Without adjustment, consumption-based rates ($/kWh and $/kW) link profits to sales
  - The more kilowatt-hours a utility sells, the more money it makes
  - This is because, in most hours, the price of electricity is greater than the cost to produce it
    - *Utility makes money even when the additional usage is wasteful, and loses it even when the reduced sales are efficient*
- The profit incentive to increase sales is extremely powerful

Assumptions for A Sample Utility

Assumptions	
Operating Expenses	$160,000,000
Rate Base	$200,000,000
Tax Rate	35.00%

Cost of Capital	% of Total	Cost Rate	Wtd. Cost		Dollar Cost Amt.	
			Pre-tax	After-Tax	Pre-Tax	After-Tax
Debt	55.00%	8.00%	4.40%	2.86%	$8,800,000	$5,720,000
Equity	45.00%	11.00%	4.95%	7.62%	**$9,900,000**	$15,230,769
Total	100.00%			10.48%		

Revenue Requirement	
Operating Expenses	$160,000,000
Debt	$5,720,000
Equity	$15,230,769
Total	$180,950,769
Allowed Return on Equity	$9,900,000

Manager A: Purple Results
Manager B: Green Results
Which Manager Gets Promoted?

	Revenue Change		Impact on Earnings		
% Change in Sales	Pre-tax	After-tax	Net Earnings	% Change	Actual ROE
5.00%	$9,047,538	$5,880,900	$15,780,900	59.40%	17.53%
4.00%	$7,238,031	$4,704,720	$14,604,720	47.52%	16.23%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
0.00%	$0	$0	$9,900,000	0.00%	11.00%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-2.00%	-$3,619,015	-$2,352,360	$7,547,640	-23.76%	8.39%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%

Approaches to the Problem:

- Straight Fixed Variable (SFV) Rate Design
  - Short-run fixed costs translated into fixed customer charge or ratcheted demand charge
- Adjustments for net lost revenues under traditional ROR ratemaking
  - Compensates utility for contribution to fixed costs that is lost as a consequence of successful specifically identified distributed resource deployment
- Decoupling
  - Ratemaking is reformed to break the link between sales and profits entirely

One Approach to Decoupling: Per-Customer Revenue Cap

- A truth that traditional regulation ignores:
  - ***In the short run, electric utility costs vary more closely with changes in numbers of customers than they do with changes in electricity sales***
- A per-customer revenue formula tells the company how much money it will be allowed to keep, on average, for every customer it serves
  - This gives the company a very strong incentive to make sure its customers are efficient, that is, that they impose as few costs upon it as possible: the fewer the costs, the greater the share of revenue that can go to its bottom line

What is Revenue Per Customer Decoupling (RPC)?

- RPC is an extension of traditional ratemaking
- RPC begins with a traditional rate case and traditional pricing structures
- However, instead of setting prices and ignoring changing throughput (and profits), RPC sets a target revenue per customer for each class and periodically adjusts prices so that the average "revenues per customer" for each class remain at the target level
- RPC uses "known" values (billing determinants) and is not subject to significant "judgment" issues – as a result, RPC is less likely to be the subject of controversy regarding inputs or calculations
- Is a revenue mechanism, not a rate design mechanism

Per-Customer Revenue Formula

- Revenue-per-customer (RPC)
  - RR_t/number of $customers_t$ = revenue per customer (RPC)
- The RPC can be adjusted by inflation (*I*), productivity (X), and exogenous factors (Z) to allow for multi-year plan
  - Revenues in the first year (RR_t) are calculated in the traditional manner: a revenue requirements analysis (e.g. California)
- $RPC_{(t+1)} = [RPC_t * (1 + I_t - X_t)] \pm Z_t$
- Allowed revenues in year t + 1
  - $RR_{(t+1)} = RPC_{(t+1)} *$ number of $customers_{(t+1)}$
- ***Important: This is <u>not how rates should be designed</u>, but only how revenues should be determined***

Pricing Under RPC Formula

- Prices are still set in the usual way
  - Consumption-based unit prices: per therm, per kWh, per kW, etc.
  - Retains customer incentives for efficiency
- Prices are adjusted periodically (up or down) to reflect:
  - Changes in the allowed revenues and
  - Over- or under-collections from the previous periods

Use Per Customer Trends: An Important Factor to Consider

- Average Use Per Customer is not a constant
  - Is already going up or down over time
- Changes in types of end-uses change:
  - More efficient appliances, but
  - More appliances and
  - More energy intensive appliances
- Changes in types of new customer facilities change usage patterns
  - Energy efficient building codes
  - New appliances tend to be more efficient than old appliances
  - Types of building being built or converted can be radically different from average "old" customers

Use Per Customer Trends: How It Impacts Utility

- If going down
  - Utility is on declining profit path between rate cases
  - If you do nothing else, RPC acts as an attrition (some might say "windfall") mechanism
- If going up:
  - Utility is on an increasing profit path between rate cases
  - If you do nothing else, RPC reduces profitability path

What to do?: "K" Factor To The Rescue

- K Factor is a variable used to address changing revenue per customer issues
  - Can be used to eliminate shortfalls or windfalls occasioned by use of RPC
  - Can also be used to "push" efficiency targets
- K Factor is a variable used to impose a "slope" on an otherwise flat RPC curve and allows the RPC to go up or down over time, depending on policy objectives
- K Factor is like having a fine tuning knob for rates

PP&L Case Study: Time Frame

- October "Reference Month"
- December "Filing Month"
- February "Billing Month"

PP&L Case Study: Residential Energy Charge Target RPC (TRPC) Calculation

Test Year Data For Month of October		
1	Test Year Price	$0.01644
2	Test Year Billing Units	824,896,488
3	Test Year Energy Revenues (L1 x L2)	$13,561,110
4	Number of Test Year Customers	1,139,330
5	$TRPC_{Energy}$ (L3 ÷ L4)	$11.9027

PP&L Case Study: Residential Energy-based Charge Computation of Revenue Adjustment

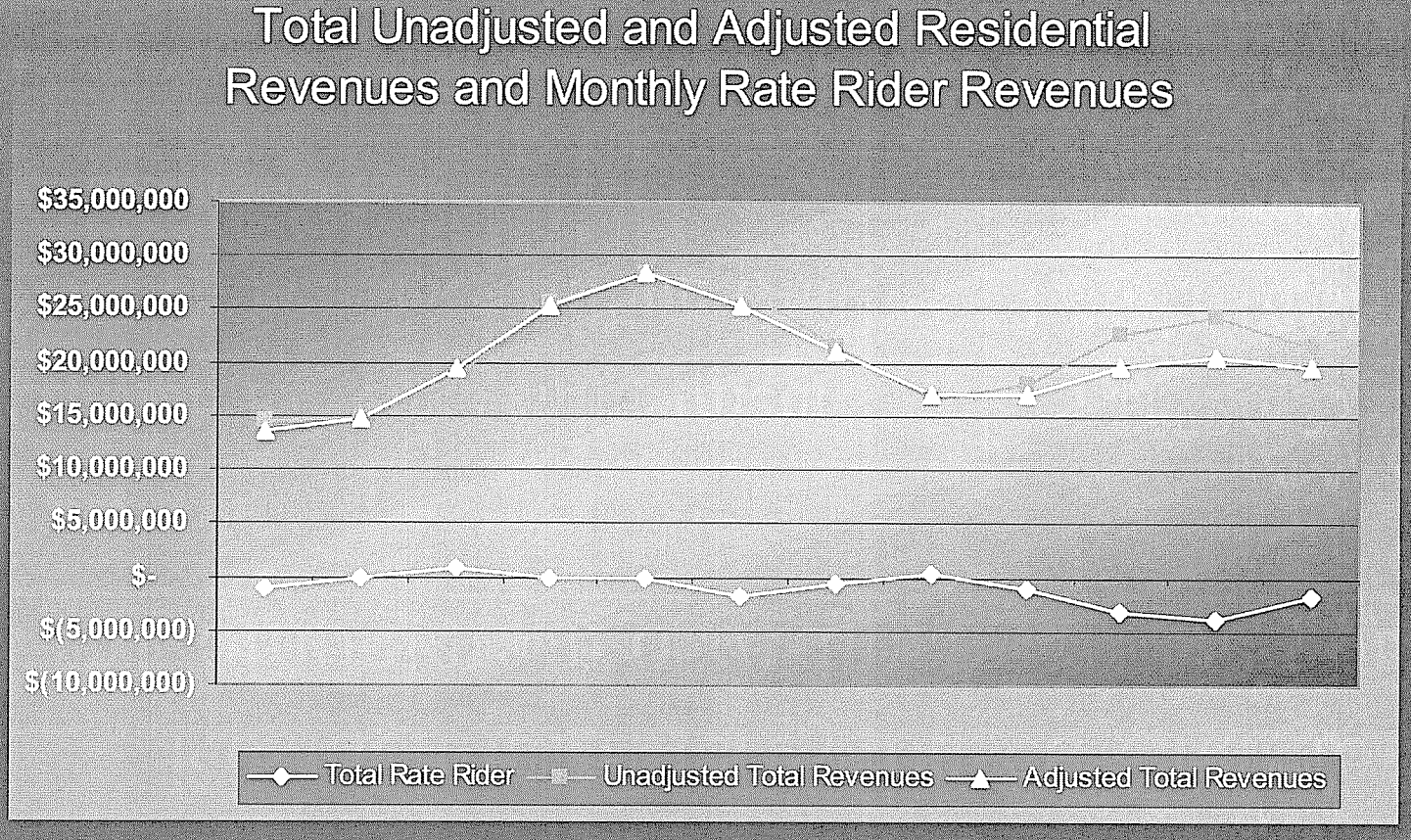
	Reference Period Data For Month of October	
1	Test Year Price	$0.01644
2	Reference Period Billing Units	880,313,022
3	Reference Period Revenues (L1 x L2)	$14,472,145
4	No. of Reference Period Customers	1,165,022
5	Target Revenue Per Customer	$11.9027
6	Allowed Revenues (L4 x L5)	$13,745,627
7	Revenue Adjustment (L6 – L3)	$(726,518)

PP&L Case Study: Residential Energy-based Charge Computation of Adjustment Factor

1	Required Revenue Adjustment	$(726,518)
2	Expected February Billing Units	1,465,616,561
3	Adjustment Factor* (L1 x L2)	$(0.000496)

*This is the amount by which the rate case price is adjusted up or down.

PP&L Case Study Backcast: What Would Have Happened?



RPC: Pros and Cons

- Pros:
  - Simplicity – a simple extension of traditional ratemaking (not unlike a fuel adjustment clause in terms of administrative burden)
  - Captures all conservation and energy efficiency (not just specific programs as in Net Lost Revenue approach), without M&V costs
  - Optionally places weather risk on customer (easiest to administer) or company (requires weather normalization of billing information for each RPC adjustment)
  - K Factor gives fine-tuning ability
  - Allows any rate design
- Cons:
  - May inadvertently serve as "attrition" adjustment
  - Not as finely tuned as Net Lost Revenue approach
  - May not work well for large customer classes (especially if few customers in class)
- Pro or con?: Should be combined with regular rate cases (3-5 years) to recalibrate RPC values.

RPC Adds New Policy Tools With Choices to Make

- Should RPC be "profit neutral"?
- Should RPC be tweaked to impose more aggressive energy efficiency?
- How often should RPC adjustments be made?
- Should RPC be combined with PBR or other incentive mechanisms
- What about risk and cost of capital?

Decoupling: California Style

- Includes RPC
- Uses authorized annual margin
- Comprehensive PBR mechanism
  - Adjusts for inflation, productivity, etc.

California Decoupling: Pros and Cons

- Pros
  - Captures weather and conservation
  - More control over changes in margin from year to year based on formulas (inflation, customer growth, etc) versus being tied strictly to rate case margin per customer
  - Includes all customer classes
  - Allows any type of rate design
- Cons
  - Much greater complexity in determining annual changes in margin
  - Data and formula intensive
  - May be too California-centric
- Pro or con?
  - Regular rate case calibrations
  - Uses a rate case cycle of 3 or 4 years.

Decoupling Examples

- California – All gas & electric IOUs
  - e.g. http://www.sdge.com/tm2/pdf/EPBR.pdf
- Oregon
  - Northwest Natural Gas
    - Limited to "decoupling" revenues associated with 90% of the non-weather induced variation in usage for residential and commercial customers
    - Has both price elasticity and "deferral" mechanisms
  - See Lisa Schwartz, Oregon PUC Staff
- Maryland
  - Washington Gas
  - Baltimore Gas & Electric (source of MADRI approach)
  - See Calvin Timmerman, MD PSC staff)
- North Carolina – Piedmont Gas
- New Jersey – Filing pending for NJ Natural Gas
  - See Michael Winka, NJBPU Staff
- Ohio – Filing pending for Vectren
  - See Janine Midgen-Ostrander - Ohio's Consumers' Counsel
- Washington – Filing pending for Puget Sound Energy and Cascade

Beyond Disincentives: Performance Incentives

- Decoupling and, to a lesser extent, net lost revenue recovery remove the profit *disincentive* to EE investment
- To encourage superior performance, utility may earn positive financial incentives (ROE adder)

Performance Incentives: For Both ROR and RPC

- Shared savings
  - Return to utility of some fraction (say, 10-20%) of the savings (avoided costs) from distributed resource deployment
    - Goes directly to utility's bottom line
  - Collars and dead bands
- Performance targets
  - Specified rewards (e.g., % of program budget) for achieving a mix of targets
    - Energy savings, capacity reductions, customer installations, reductions in program administration costs, etc.
- ROE adder
  - A premium on the ROE applied to unamortized portion of EE costs included in ratebase

RPC: What's in it for the customers?

- Lower total cost
  - EE is usually the cheapest resource on the margin – see California experience
- Reduced externalities
  - EE is the cleanest resource available
  - Reduced water consumption (see SWEEP "Mother Lode" report)
- Correctly aligns profitability with public policy (something traditional regulation does not do)

Myths and Misunderstandings About Decoupling

- Utilities already have a duty to deliver lowest cost service, so no remedy is required
- Decoupling makes customers pay for energy not used and raises prices
- Too complex or hard to administer

In closing…

- All regulation is incentive regulation, so consider the incentives you currently give utilities and compare them to your public policy objectives
- No matter what approach you take, you should establish aggressive energy efficiency and conservation targets that should or must be met to entitle utility to decoupling adjustment
- Utility's least cost option should be its most profitable course of action

NARUC 1989 Resolution

Resolution in Support of Incentives for Electric Utility Least-Cost Planning

WHEREAS, National and International economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; and

WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and

WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration are often more responsible economically and environmentally than traditional generation expansion; and

WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and

WHEREAS, The ratemaking formulas used by most state commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end-use efficiency; and

WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and

WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and

WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and

WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and

WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC) assembled in its 1989 Summer Committee Meeting in San Francisco, urges its member state commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise **ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action**.

Sponsored by the Committee on Energy Conservation, Adopted July 27, 1989

Thanks for Your Attention

- More Resources:
  - MADRI Website:
    - http://www.energetics.com/madri
    - PDF Versions of all documents, meeting schedules, etc.
  - MADRI Weblog:
    - http://www.raponline.org/madri
    - Excel and Word versions of selected working documents
    - See specifically:
      - MADRI Model Revenue Stability Rate Rider
      - PPL Case Study (Excel Spreadsheet)
- RAP Website: http://www.raponline.org
- E-mail: rapwayne@aol.com

What About the Long Term?

- Costs may vary with numbers of customers in the short run (several years), but in the long run costs are driven by demand
- Thus, the prices that consumers pay must be designed to reflect the causes of costs in the long run
  - Therefore, consumption-based prices
- Each customer does not pay the RPC
  - The RPC is merely a tool for calculating how much money the company is entitled to each year.

LBL-34555
UC-350

The Theory and Practice of Decoupling

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January 1994

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Recycled Paper

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Abstract

Decoupling revenues from sales is an important regulatory option under consideration by regulators seeking to transform utilities from sellers of a least-cost energy commodity to providers of least-cost energy services. This report examines decoupling from three perspectives. First, we consider threshold issues for decoupling, including characterization of the ratemaking practices addressed by decoupling which make incremental sales profitable to utilities, the role of rate case frequency in limiting the consequences of this incentive, and finally the existence of other incentives to sell electricity, which are not addressed by decoupling. Second, we examine the operation and performance of decoupling, including the mechanics of decoupling as a between-rate-case modification to the traditional ratemaking process, the ability of revenue-per-customer decoupling versus traditional ratemaking to recover nonfuel costs accurately, and a comparison of the profit implications of various decoupling approaches. Third, we review the rate impacts of decoupling for California's electric utilities, which have had the longest experience with decoupling.

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Executive Summary

Alfred Kahn once said "all regulation is incentive regulation." Nowhere is the challenge that is implicit in this observation greater than in current debates about regulatory reforms in support of integrated resource planning. Integrated resource planning (IRP) requires that a utility consider all resource options for meeting customers' energy service needs in a consistent fashion. For both demand-side and nontraditional resources, questions have been raised about the appropriateness of traditional utility rate regulation for aligning utilities' earnings incentives with the goals of IRP. If the utility management cannot increase shareholder earnings through better procurement of resources, why should we expect that they will be efficient?

Specific disincentives that have been noted for customer energy efficiency programs include: (1) utilities may not recover demand-side management (DSM) program expenses when these expenses have not been accounted for in some previous rate-setting process; (2) utilities may lose revenue from sales not made because of the success of customer energy efficiency programs; and (3) utilities may forego earnings opportunities because resources are devoted to DSM programs rather than to other profit-making activities.

Various regulatory changes have been proposed to address these disincentives. Of these, decoupling, which addresses the issue of lost revenues, has been the subject of controversy. Decoupling refers to a class of automatic or semi-automatic annual ratemaking adjustments that ensure collection of an agreed-upon level of revenues independent of actual sales.

Proponents argue that, without decoupling, a utility has powerful incentives to promote incremental sales and equally powerful disincentives to reduce sales growth through successful DSM programs. According to this perspective, decoupling is required in order to make utilities indifferent to sales gains or losses[1] and thereby to free utilities to promote customer energy efficiency programs, in order to achieve integrated resource planning objectives.

Opponents raise concerns about several aspects of decoupling. First, they question the exact nature and size of the incentive for incremental sales and the ability of decoupling to mitigate this incentive. Second, decoupling represents a form of automatic

[1] For this reason, proponents of decoupling also argue that decoupling is superior to net lost revenue adjustments because these adjustments deal only with revenue losses directly attributable to utility DSM activities while leaving the underlying incentive to make incremental sales unaffected.

ratemaking, so it could diminish the centrality of the rate case as the primary forum for examining (and contesting) utility practices. Third, decoupling, as implemented currently, may inappropriately shift business risks from utility shareholders to ratepayers, possibly leading to undesirable rate impacts.

The goal of this report is to provide a broad framework in which to address these concerns. We have structured our work around three questions: (1) Why decouple? (2) How does decoupling work? (3) What have been the rate impacts of decoupling?

Why Decouple?

Stated simply, there is an incentive for a utility to sell additional electricity whenever marginal revenues exceed marginal costs. Between rate cases, because prices are fixed by definition (i.e., to a first approximation, marginal revenue equals average revenue), profitability is determined by the cost structure of the utility. We demonstrate analytically how, between rate cases, profits depend on: (1) the initial profit margin of the utility (prior to the incremental sales); (2) the fraction of total costs affected by the production expenses incurred to make incremental sales (i.e., the variable cost fraction); and (3) the way in which this fraction is affected (i.e., marginal versus average variable costs).

The analysis provides a generalizable approach for assessing specific claims of profitability (e.g., "a 1% increase in sales leads to X additional basis points in return on equity"). Using this approach, we find that the cost structures of most investor-owned utilities do indeed make incremental sales profitable. See Figure EX-1.

At the same time, the frequency of rate cases limits the opportunities for these marginal revenue/marginal cost relationships to make incremental sales profitable. In this regard, the incentive to sell electricity between rate cases is simply a consequence of regulatory lag.

Finally, we believe there are there other incentives, besides regulatory lag, for utilities to build load. The issue for decoupling is whether there truly are incentives (or really disincentives) and, if there are incentives, how are they addressed by decoupling? We believe a broader discussion of these issues is appropriate when considering decoupling as a remedy for the lost revenue problem.

Figure EX-1. Profitability of 1% Sales Increase

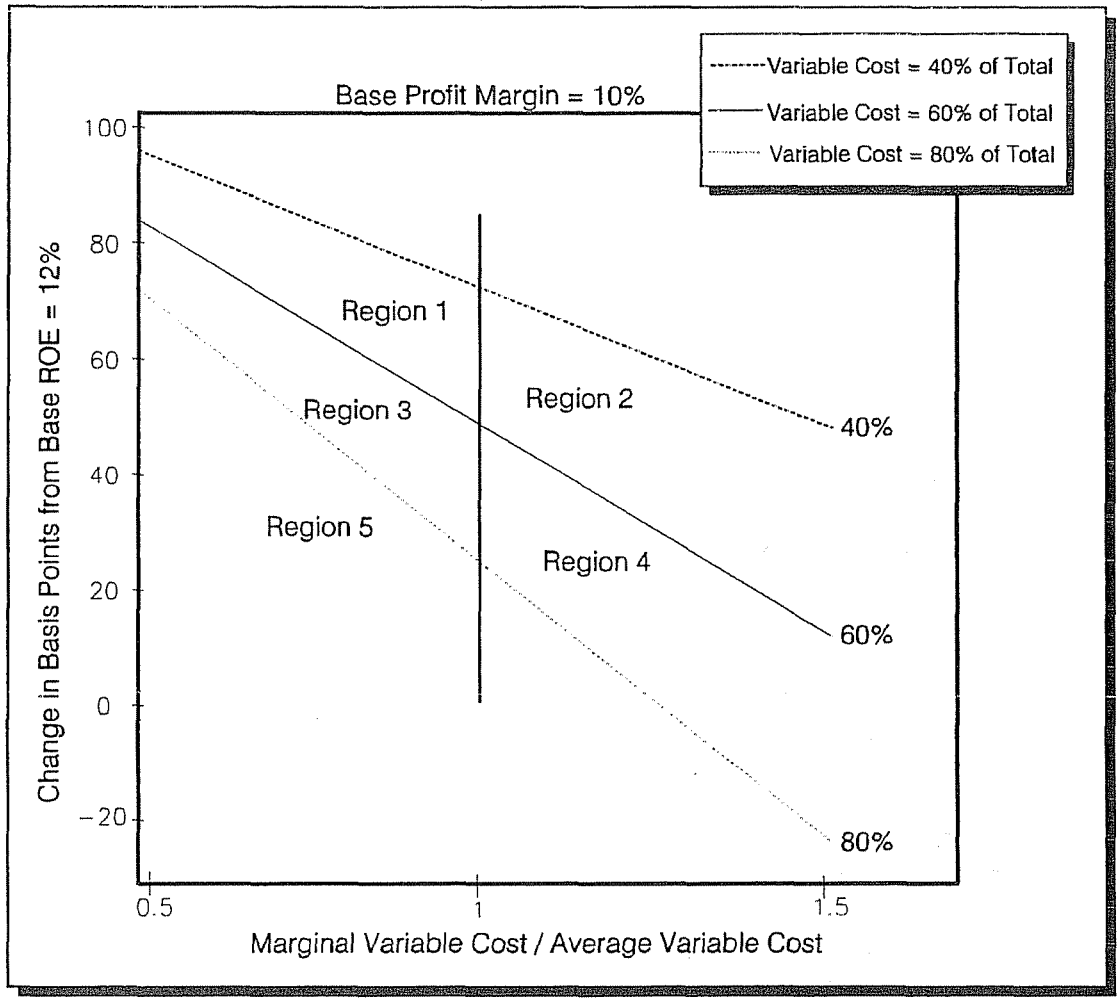


Figure EX-1 illustrates the relationship between a 1% increase in sales and the resulting increase (or decrease) in profit. The results are presented for three levels of variable costs as a fraction of total costs (40%, 60% and 80%), which are represented by three downward-sloping horizontal lines. Alternative marginal variable to average variable cost relationships are represented along the horizontal axis. The resulting change in profit, expressed as a change in return on equity, normalized to an initial 12%, is depicted on the vertical axis. Using FERC Form-1 data from 1987 and 1988, we mapped the current cost structure of U.S. electric utilities onto this graph. Of the 122 utilities examined, 33% are in Region 1, 20% are in Region 2, 31% are in Region 3, 12% are in Region 4, and 4% are in Region 5. This graph indicates that, when prices are fixed, there are very few situations in which increased sales cannot lead to increased profits.

How Does Decoupling Work?

Looking at the specific operation of decoupling mechanisms, we observe that the critical distinction between traditional ratemaking and decoupling lies with the focus and frequency of the ratemaking process. Traditional ratemaking focusses on *rate*-setting in the context of a rate case cycle, which typically spans many years. Decoupling does not change this basic process, but adds to it an explicit means for setting revenues during the period between rate cases. In so doing, decoupling eliminates the incentive to increase sales between rate cases, since revenues will be unaffected by actual sales.

We develop formal expressions that describe the rate-setting mechanics of traditional ratemaking and all current forms of decoupling: the Electric Revenue Adjustment Mechanism (ERAM), as practiced in California; the related Revenue Decoupling Mechanism (RDM) used in New York; and the Revenue-Per-Customer approach (RPC), as practiced by Central Maine Power in Maine and Puget Power in Washington.

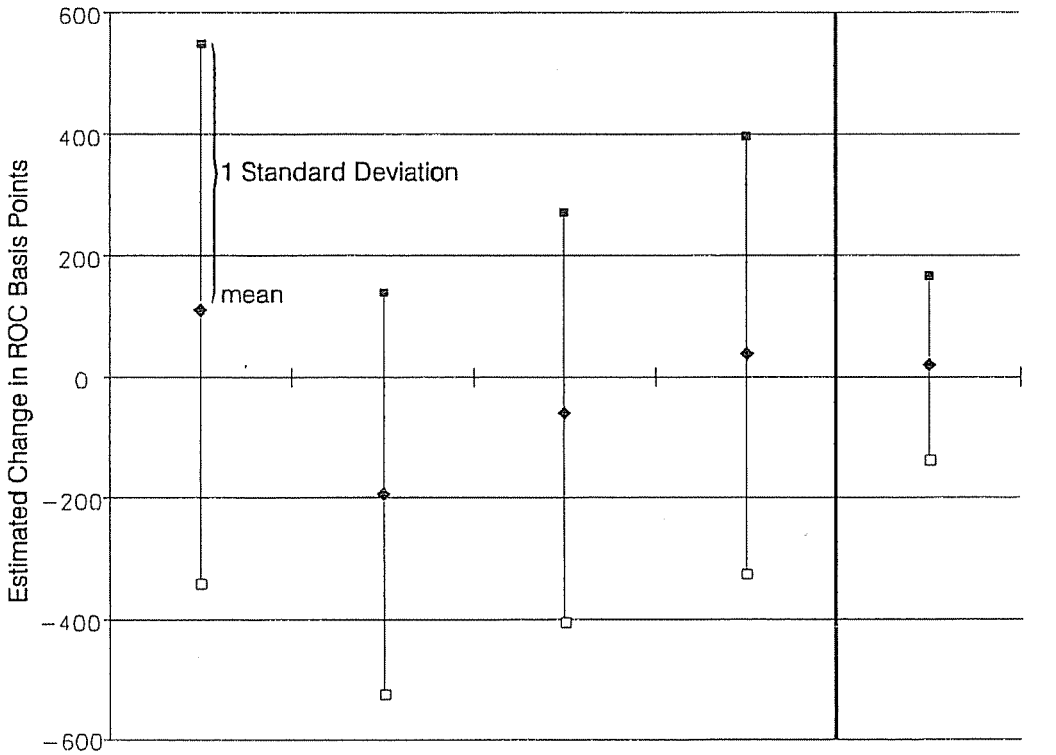
We evaluate the ratemaking approaches by first examining how traditional ratemaking and RPC treat cost-recovery between rate cases. This perspective is important because setting rates equal to the cost of service is a fundamental principle of the ratemaking process. The inability of rates to recover costs is a primary justification of holding rate cases to realign rates and costs. Because most utilities operate with some form of fuel adjustment clause, which passes fuel and purchased power costs through to consumers, the generic issue is how each ratemaking process accounts for nonfuel cost changes. Traditional ratemaking, by fixing prices between rate cases, links the recovery of nonfuel costs to changes in load. RPC, by recoupling revenues to numbers of customers links the recovery of these costs to changes in the number of customers.[2]

Relying on 25 years of aggregate financial statistics from 160 investor-owned utilities, we find that one-year changes in load or numbers of customers are both poorly-correlated with changes in nonfuel costs. Hence, the proponents of RPC are correct in arguing that RPC does no worse than traditional ratemaking in tracking nonfuel costs (indeed, we find it does slightly better). Nevertheless, as long as cost of service is an important ratemaking principle, there will remain a need for periodic rate cases under both traditional ratemaking and RPC decoupling.

Using the same historic data, we then directly examine the profitability bias inherent in each ratemaking approach; the results are summarized in Figure EX-2. We find, as was

[2] The assumptions regarding nonfuel cost changes cannot be readily examined for ERAMs because ERAMs recouple sales to attrition mechanisms, which vary greatly in the way in which they adjust authorized revenue requirements between rate cases.

Figure EX-2. Profitability of Traditional Ratemaking and Decoupling Revenue Adjustment Mechanisms



	Traditional Ratemaking	Basic RAM	Revenue-per-Customer	LBL-RAM	California ERAM[1]
Mean	107	-191	-66	36	15
Std Dev	442	328	331	353	144
# of Obs	3,102	3,103	3,102	3,103	32

[1] ERAM values based on ROE

Figure EX-2 depicts expected incremental profit (above or below authorized profit) for each ratemaking scheme. To calculate these values, we simulated the different ratemaking processes using a historic test year and three year rate case cycle. In each case, authorized profit equals zero, reflecting a perfect match between revenue and cost (where cost includes capital expenses). The incremental profit depicted in this figure reflects the theoretical amount of revenue that would be allowed under each ratemaking scheme less actual expenses incurred. The California ERAM results reflect actual authorized revenue and actual expenses.

previously determined analytically, that traditional ratemaking has, on average, a modest positive bias that increases profits between rate cases (since loads have been growing). In contrast, RPC has a small but negative bias that lowers profits on average (even though numbers of customers have also been growing). California's ERAM also has a slightly positive earnings bias, but with smaller variance, which we speculate is related to the detailed attrition underlying ERAM.

The variance we observe in these results is much greater than is the tendency of a given approach to bias profits in a particular direction. In other words, other factors, such as business practices, other regulations, and the general business climate, will likely have a greater influence on profits than will these specific ratemaking approaches.

What Have Been the Rate Impacts of Decoupling?

In the final section of the report, we consider the effect that decoupling has had on rate volatility and risk-shifting with a detailed review of the rate history of the electric utilities with the longest history of decoupling: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).[3]

We find that, for most California utilities, decoupling has actually reduced rate volatility compared to a situation in which there is no decoupling.[4] Decoupling can in principle add to or counteract other sources of rate volatility and, in California, the net effect has been one of offsetting these other sources. Assessing the rate impacts of ERAM along with the other influences on rates also provides a basis for commenting on the magnitude of risk-shifting accounted for by ERAM. The record in California indicates that the risk-shifting accounted for by ERAM is small or non-existent and, in any case, ERAM has contributed far less to rate volatility than have other adjustments to rates, such as the fuel-adjustment clause. See Table EX-1.

[3] Revenues for the Southern California Gas Company, as well as the gas departments of PG&E and SDG&E, are also partially decoupled (for core customers only) through an ERAM-like mechanism, but are not examined in this study.

[4] This approach to measuring the effect of ERAM on rates assumes that, without ERAM, the monies accrued in the ERAM balancing account would not otherwise be recognized through some other revenue adjustment, such as attrition or more frequent rate cases.

Table EX-1. Annual Changes in Revenue Requirement and Retail Rates

	PG&E		SCE		SDG&E	
	Rates w/ERAM (%)	Rates w/o ERAM (%)	Rates w/ERAM (%)	Rates w/o ERAM (%)	Rates w/ERAM (%)	Rates w/o ERAM (%)
Mean	4.9	4.8	3.2	3.2	-1.5	-1.6
Std. Dev.	7.5	9.6	7.7	7.5	7.4	7.9

Concluding Thoughts

We believe there are three issues for utilities and regulators who are considering decoupling. First, the importance of lost revenues and therefore of decoupling depends strongly on pre-existing features of regulation. Foremost among these is the frequency of rate cases and the design of fuel adjustment clauses because they directly influence the size and persistence of the disincentives that decoupling seeks to address. At the same time, we also believe there are other incentives (and disincentives) for utilities to build load, which are distinct from the lost revenue problem. Regulatory reforms, therefore, should not focus exclusively on lost revenues, but instead take a broad perspective in trying to align utility incentives with the objectives of integrated resource planning.

Second, adoption of a decoupling mechanism requires consideration of the means by which revenues are set between rate cases, especially the means for accounting for changes in nonfuel costs. Our examination of the empirical record suggests that, over short periods of time, neither sales growth (which underlies traditional ratemaking) nor customer growth (which underlies RPC) provide a very powerful basis for explaining changes in these costs. In other words, the revenue-per-customer approach (in addition to decoupling sales from revenues) will on average do no worse than traditional ratemaking in recovering these costs. Thus, if cost-recovery is an important ratemaking objective, it is a separable concern from decoupling for which other approaches should be considered, such as attrition mechanisms or future test years.

Third, the record in California suggests that the issue of the additional rate volatility introduced by decoupling has been overemphasized. We believe that discussions of the additional rate volatility and risk-shifting associated with decoupling should be conducted in a framework that considers all sources of rate volatility and risk-shifting in ratemaking. In this framework, the questions of what the risks are and who is best suited

to bear them can be made explicit and their treatment made comprehensive, rather than piecemeal.

Decoupling can play an important role in transforming utilities from sellers of a least-cost energy commodity to providers of least-cost energy services, but it is no panacea. While it can successfully eliminate an important disincentive for utility DSM programs, it must be designed carefully to take explicit account of other regulatory objectives, such as cost-recovery and rate volatility.

Chapter 1

Introduction

Alfred Kahn once said "all regulation is incentive regulation." Nowhere is the challenge that is implicit in this observation greater than in current debates about regulatory reforms in support of integrated resource planning. Integrated resource planning (IRP) requires that a utility consider all resource options for meeting customers' energy service needs in a consistent fashion. For both demand-side and nontraditional resources, questions have been raised about the appropriateness of traditional utility rate regulation for aligning utilities' earnings incentives with the goals of IRP (Moskovitz 1989).

Specific disincentives that have been noted for customer energy efficiency programs include: (1) utilities may not recover demand-side management (DSM) program expenses when these expenses have not been accounted for in some previous rate-setting process; (2) utilities may lose revenue from sales not made because of the success of customer energy efficiency programs; and (3) utilities may forego earnings opportunities because resources are devoted to DSM programs rather than to other profit-making activities (Nadel et al. 1992).

Various regulatory changes have been proposed to address these disincentives. Of these, decoupling, which addresses the issue of lost revenues, has been the subject of controversy. Decoupling refers to a class of automatic or semi-automatic annual ratemaking adjustments that ensure collection of an agreed-upon level of revenues independent of actual sales (Marnay and Comnes 1990).

Proponents argue that, without decoupling, a utility has powerful incentives to promote incremental sales and equally powerful disincentives to reduce sales growth through successful DSM programs (Moskovitz 1989). Proponents of decoupling have developed stylized examples indicating that incremental sales are highly profitable. Published quantifications of these findings include "5 cents in profits for every additional kWh sold" (Moskovitz 1989) and "130 basis points for a 1% increase in sales growth" (Hirst and Blank 1993).

According to this perspective, decoupling is required in order to make utilities indifferent to sales gains or losses and thereby to free utilities to promote customer energy efficiency programs, in order to achieve integrated resource planning objectives (Moskovitz and Swofford 1991). For this reason, proponents of decoupling also argue that decoupling

is superior to net lost revenue adjustments[5] because these adjustments deal only with revenue losses directly attributable to utility DSM activities while leaving the underlying incentive to make incremental sales unaffected (Moskovitz et al. 1992).

Opponents raise concerns about several aspects of decoupling. Some point out that promotion of incremental sales is not necessarily inconsistent with integrated resource planning (Tempchin 1993). However, while this judgement may be true, the problem addressed by decoupling is that these sales may be an unintended consequence of regulation, as opposed to an intended effect of regulatory policy (Moskovitz 1993).

Opponents also question the exact nature and size of the incentive for incremental sales and the ability of decoupling to mitigate this incentive. How universal are the stylized examples indicating highly profitable incremental sales? Moreover, how important is the profitability of incremental sales, so construed, relative to other profit-making opportunities available to the firm? This second issue has been identified as a specific limitation of decoupling because decoupling does not address other incentives in regulation, which span the rate case cycle (Binz 1992).

Concerns have also been raised that decoupling represents a form of automatic ratemaking (along with fuel adjustment clauses and some forms of attrition), so it could diminish the centrality of the rate case as the primary forum for examining (and contesting) utility practices, regulatory policies, and customer impacts. This issue is closely related to the previous one because the rate case has been the traditional forum for reviewing utility business activities. There are also specific questions regarding the ability of the Revenue-Per-Customer decoupling approach to track nonfuel expenses accurately (Chamberlin 1992).

Finally, there are concerns that decoupling, as implemented currently, may inappropriately shift business risks from utility shareholders to ratepayers, possibly leading to undesirable rate impacts. Indeed, concerns over rate impacts have led to reconsideration of decoupling in both Washington and Maine. One approach for addressing this concern has been the formulation of disaggregated sales models intended to more precisely allocate specific risks between ratepayers and shareholders (Hirst 1993). Yet another approach is to design cost-recovery policies that minimize year-to-year fluctuations in rate impacts (Moskovitz et al. 1993). One hybrid approach involves invoking alternative procedures, which are triggered by the magnitude of expected rate impacts (Eachus 1993).

[5] Net lost revenue adjustments attempt to compensate utilities for revenues, less avoided production costs, lost from explicitly identified utility DSM programs (see Nadel et al. 1992).

The goal of this report is to provide a broad framework in which to address these concerns. We have structured our work around three questions:

1) Why decouple? (Chapter 2)
2) How does decoupling work? (Chapters 3, 4, and 5)
3) What have been the rate impacts of decoupling? (Chapter 6)

In Chapter 2, we consider threshold issues for decoupling by characterizing precisely the underlying conditions leading to the profitability of incremental sales. The general methods we develop allow the reader to examine the relative profitability of incremental sales for a variety of circumstances. We also detail the limitations of our characterization and, therefore, of the utility's incentive for incremental sales. In a final section, we discuss a separate incremental sales incentive that decoupling does not address.

In Chapter 3, we examine how decoupling works by contrasting its operation with the traditional rate-setting process. We formalize our discussions with mathematical expressions to describe the rate-setting process more precisely. The discussions illustrate the relationships that regulation (with and without decoupling) establishes among sales, customer, and sales growth.

In Chapter 4, we examine some of the factors that have influenced nonfuel cost growth in the past; in the presence of fuel adjustment clauses, decoupling affects only the recovery of nonfuel costs. Our analysis is based on 25 years of annual financial statistics from 160 utilities representing about 80% of US electricity sales (FERC Form-1). This examination provides an empirical basis for evaluating the relationships formalized in Chapter 3 and directly addresses issues raised by Moskovitz (1992) regarding the relationship between load growth versus customer growth on the one hand and nonfuel costs on the other.

In Chapter 5, we conduct a "what-if" evaluation of the performance of traditional, sales-coupled rate regulation; two current decoupling revenue adjustment mechanisms, Revenue-Per-Customer and Electric Revenue Adjustment Mechanism (ERAM); and two additional, hypothetical decoupling approaches. The evaluation is based on simulating the performance of each ratemaking mechanism using our data set of historic utility costs, customers, and sales to determine the effect of each mechanism on utility profits and profit volatility. This evaluation provides a bottom line for the theoretical relationships established in Chapter 3 and the empirical record discussed in Chapter 4.

In Chapter 6, we review California's experience with ERAM. We complement previous work describing the mechanics of ERAM (Marnay and Comnes 1990) with information

on the actual rate impacts experienced by California's major investor-owned electric utilities: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). In order to shed light on the risk-shifting impacts of ERAM, we quantify both the marginal and total impacts of ERAM in the context of the many rate adjustments experienced by California ratepayers during the past 14 years

In Chapter 7, we summarize our work by identifying issues for utilities and regulators to consider in evaluating the applicability of decoupling to their situations.

Four appendices follow. The first appendix describes the mathematical derivations underlying the calculation of between-rate-case profitability presented in Chapter 2. The second appendix describes the FERC data used to the analyses presented in Chapters 4 and 5. The third appendix complements the discussion in Chapter 4 with additional statistical analyses of the FERC data to identify better determinants of nonfuel costs. The fourth appendix complements the discussion in Chapter 6 with a formal quantification of the cost to consumers of risks associated with rate volatility.

Chapter 2

How Does Traditional Ratemaking Influence the Profitability of Incremental Sales?

This chapter considers the threshold question for decoupling: what are the incentives for incremental sales in traditional utility ratemaking? We begin by examining a commonly referenced characterization of the ratemaking process; this characterization focuses on the period between rate cases. For ease of presentation, we rely on a representative income statement for a composite utility in order to quantify the effects of additional revenues (from incremental sales) on utility profits. Our objective is to establish a framework for understanding the design and performance of the decoupling mechanisms that are discussed in subsequent chapters. We also consider the limitations of our characterization and, consequently, of decoupling as well. Demarcation of these limitations clarifies the differences between conflicting views on the ultimate effectiveness of decoupling in transforming utilities from sellers of an energy commodity to providers of energy services.[6]

2.1 The Between-Rate-Case Incentive to Sell Electricity

Table 2-1 presents a representative income statement for a composite utility. Revenues, for simplicity, are just sales multiplied by an average price. Average price has been fixed at 70 mills/kWh and sales have been derived to yield an arbitrary total revenue of $100. Costs consist of fuel, nonfuel O&M, depreciation, interest, and taxes. Although these costs have been normalized to be consistent with a total revenue of $100, the fractions of revenues that they represent reflect a composite of U.S. investor-owned utilities, as reported in the Energy Information Agency's most recent annual survey of utilities (Energy Information Administration (EIA) 1993).

Net income or profit is just the difference between revenues and costs. Net income can be expressed in several ways. For example, net income can be expressed as a percentage of total revenues, which can also be thought of as a profit margin, or as a return on equity, through specification of the capital structure of the utility. In this example, the initial situation of the utility, as represented in the first column of Table 2-1, indicates a profit margin of 10% and a return on equity of 12%.

[6] See Krause and Eto (1988) for an articulation of the rationale for this transformation.

Table 2-1. Profitability of 1% Sales Increase Without Decoupling - Examples

($ unless noted otherwise)

		Case 1 no Fuel Adjustment Clause		*Case 2 w/Fuel Adjustment Clause*	
	Base Case	Change from Base Case		Change from Base Case	
Revenue					
Sales (kWh)	1429	1.00%	1443	1.00%	1443
Price ($/kWh)	0.07	0.00%	0.07	0.00%	0.07
Subtotal	100.00		101.00		101.00
FAC Adjustment	0.00		0.00		-0.14
Total Revenue	100.00		101.00		100.86
Cost					
Nonfuel O&M	25.40	0.89%	25.63	0.89%	25.63
Fuel	33.30	0.57%	33.49	0.57%	33.49
Depreciation	9.70	0.00%	9.70	0.00%	9.70
Interest	8.60	0.00%	8.60	0.00%	8.60
Total Costs (before taxes)	77.00		77.42		77.42
Gross Income	23.00		23.58		23.44
Taxes	13.00		13.23		13.18
Net Income	10.00		10.35		10.27
ROE (%)	12.00		12.42		12.32
Profit Margin	10.0%		10.3%		10.2%
Variable Cost / Total Costs	58.7%		71.6%		71.6%
Marg. Variable / Avg. Variable Cost			90.7%		102.6%

- Marginal income tax rate = 40%
- Profit Margin = Net Income / Total Revenue
- Variable Cost = Nonfuel O&M + Fuel + Taxes
- Marginal Variable Cost = Change in Variable Cost divided by Change in Sales
- Average Variable Cost = Base Case Variable Cost divided by Base Case Sales

In the first change case, we consider how profits would be affected by a 1% increase in sales.[7] Marginal revenue is assumed to equal average revenue, which is to say that, in the short term (i.e., before the next rate case), the price of electricity is fixed and is assumed to be linear.[8] As a result, a 1% increase in sales leads to a 1% increase in revenue.

However, marginal cost is not equal to average cost. Not all costs are directly affected by changes in sales. Interest, depreciation, and some portion of nonfuel O&M are costs that are unlikely to vary in the very short run as a result of changes in sales and are in this sense fixed. Fuel, and some portion of nonfuel O&M costs, on the other hand, are likely to be influenced by sales and are in this sense variable. If gross income changes, taxes will also be affected.[9] In our example, these variable costs (fuel, nonfuel O&M, and taxes) account for nearly 60% of total costs.

The costs that do change in response to changes in sales can vary greatly. Marginal variable costs can either exceed or be less than average variable costs. For the two most recent, consecutive years of utility financial information in our data set (1987 and 1988), marginal variable costs (MVC) due to a 1% increase in electricity sales have been slightly more than 70% of average variable costs (AVC).[10] In other words, marginal costs are less than average costs. The aggregate change consists of the weighted average of an 89% change in MVC to AVC for nonfuel O&M costs[11] and a 57% change in MVC to AVC for fuel, plus taxes..

Marginal profitability is the difference between marginal revenues and marginal costs. Net income and return on equity increase by almost 4%. Expressed as a change in basis points from an initial return on equity of 12%, the effect works out to be about 40 basis points or less than $0.03 per kWh of incremental sales.

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[7] As will be clear in this chapter and Appendix A, all of the examples can be viewed from the perspective of the impacts of either a percentage increase in sales or a percentage decrease in sales.

[8] Many tariffs, in fact, are non-linear. Examples include block rates, time-of-use rates, demand charges, and customer charges. For the purposes of this example, we suppress these subtleties of rate design.

[9] Corporate tax strategies are very complicated. For simplicity, our examples assume that the incremental tax rate is 40%.

[10] The data set, which consists of 25 consecutive years of FERC form-1 information from over 160 investor-owned utilities, is described in Appendix A.

[11] For this example, we have adopted a simplifying convention in which all observed changes in costs are expressed in terms of a change in sales. In fact, some of these costs are fixed and some change in response to things other than sales; we take up some of these issues in Chapter 4.

Case 2 presents the same example in the presence of a stylized fuel adjustment clause. In this example, fuel costs are fully decoupled from the sales increase.[12] We represent this situation by showing a current year debit to income statement for the difference between average and marginal fuel expenses. In fact, fuel costs would increase this year, but their effect on earnings would be offset by a future year rate increase whose present value would exactly offset this year's fuel cost increase. That is, excess fuel costs would accrue in a fuel balancing account and would not affect the company's income statement.

The effect of this characterization of a fuel adjustment clause is to eliminate the influence of changes in fuel costs on the relationship between marginal variable cost and average variable cost. The variable cost fraction is unchanged, but the resulting relationship between MVC and AVC increases to about 95% (up from 71% in case 1). In this situation (with marginal fuel costs less than average fuel costs), a 1% increase in sales now translates to a more than 50 basis-point increase in return on equity.

Clearly, these results are just reflections of the specific assumptions made regarding the magnitude of the affected cost elements as fractions of total cost, the rate of change of these cost elements compared to changes in sales, and the level of profits at the start. For these examples, the assumptions reflect historic, composite industry conditions.

Fortunately, it is straightforward to generalize from these specific assumptions to treat all possible situations. Appendix A contains the mathematics underlying this generalization, in the remainder of this section, we present the results and their implications.

Figure 2-1 illustrates the relationship between a 1% increase in sales and the resulting increase (or decrease) in profit. The results are presented for three levels of variable costs as a fraction of total costs (40%, 60%, and 80%), which are represented by three downward-sloping horizontal lines. For each of these situations, alternative marginal-to-average variable cost relationships are represented along the horizontal axis. The resulting change in profit, expressed as a change in return on equity, normalized to an initial 12%, is seen on the vertical axis. The situations described for cases 1 and 2 from the previous examples are indicated.

Figure 2-1 indicates that the profitability of an increase in sales goes up: 1) as the variable cost fraction of total costs decreases because a larger fraction of costs is fixed;

[12] The design of fuel adjustment clauses can vary widely. This example represents the typical case in which all differences in per-unit fuel costs from the base case accrue in a balancing account.

Figure 2-1. Profitability of 1% Sales Increase

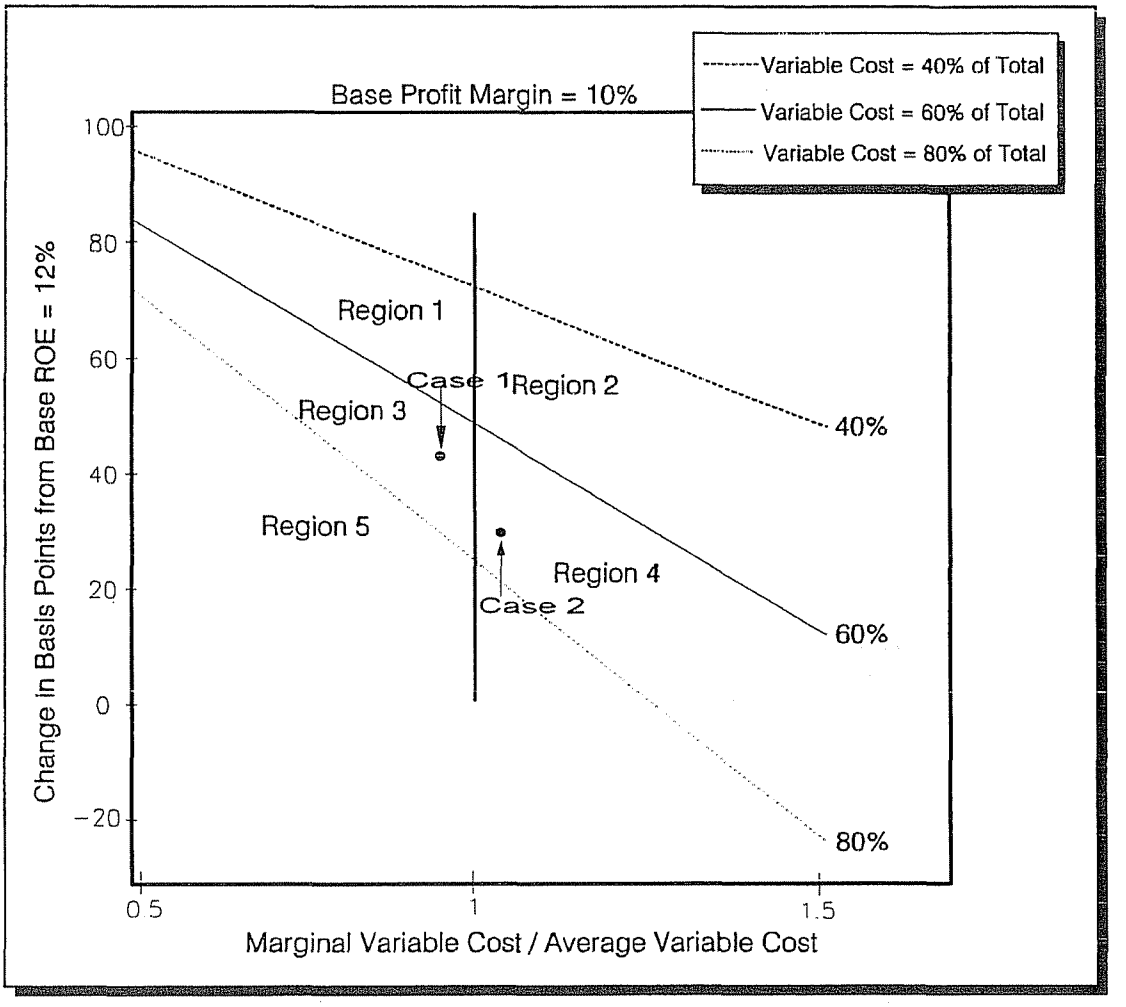


Figure 2-1 illustrates the relationship between a 1% increase in sales and the resulting increase (or decrease) in profit. The results are presented for three levels of variable costs as a fraction of total costs (40%, 60% and 80%), which are represented by three downward-sloping horizontal lines. Alternative marginal variable to average variable cost relationships are represented along the horizontal axis. The resulting change in profit, expressed as a change in return on equity, normalized to an initial 12%, is depicted on the vertical axis. Using FERC Form-1 data from 1987 and 1988, we mapped the current cost structure of U.S. electric utilities onto this graph. Of the 122 utilities examined, 33% are in Region 1, 20% are in Region 2, 31% are in Region 3, 12% are in Region 4, and 4% are in Region 5. This graph indicates that, when prices are fixed, there are very few situations in which increased sales cannot lead to increased profits. See text for discussion of Cases 1 and 2.

and 2) as the responsiveness of these costs (marginal variable-to-average variable costs) to increases in sales decreases.[13]

Table 2-2 summarizes the cost structure of the utilities examined in this report. The table identifies five cost structure regimes for utilities from the most recent year in our data set: utilities with variable cost fractions between 40 and 60% (53% of utilities), 60 and 80% (31% of utilities), and in excess of 80% (3% of utilities); and utilities with marginal variable over average variable costs equal to or in excess of one (32% of utilities), and less than one (68% of utilities). These regimes are also indicated on Figure 2-1.

Table 2-2. Cost Structure of U.S. Investor-Owned Electric Utilities

Variable Cost/ Total Cost	Marginal Variable/Average Variable Cost		
	< 1	> or = 1	Total
40 - 60%	33%[1]	20%[2]	53%
60 - 80%	31%[3]	12%[4]	43%
80 - 100%	4%[5]		4%
Total	68%	32%	100%

[1] designated as Region 1 on Figure 2-1
[2] designated as Region 2 on Figure 2-1
[3] designated as Region 3 on Figure 2-1
[4] designated as Region 4 on Figure 2-1
[5] designates as Region 5 on Figure 2-1

Based on 1987 and 1988 FERC Form-1 data for 122 utilities

Taken together, Table 2-2 and Figure 2-1 indicate that, when prices are fixed and linear, there are very few situations in which increased sales cannot lead to increased profits. First, only a fraction of the total cost of production will be affected by increases in sales. Second, the degree to which these costs are affected must exceed by a wide margin the

[13] The relationships illustrated on Figure 2-1 are also affected by the initial profit margin, which was assumed to be 10%. We show, in Appendix A, that the general conclusions are robust for a range of initial profit margins (See Figure A-1).

percentage increase in sales in order to offset the increase in revenues from sales. That is, for the broad range of conditions characterizing the cost structure of the electric industry today (40 to 80% of total costs being affected by a change in sales), costs must increase by a factor of two to three times the percentage increase in sales. If costs do not increase this sharply in response to changes in sales, increased sales will always lead to increased profits.

2.2 The Rate Case is a Limit to this Incentive

The profitability of increased sales described in the previous section depends on two critical assumptions: 1) retail rates are fixed and linear so that marginal revenue is equal to average revenue, and 2) some fraction of costs are fixed and therefore marginal costs are usually less than average costs. In this section, we consider the ways in which rate cases limit the consequences of these assumptions.

During rate cases, fixed and variable costs are considered simultaneously. Adjustments are made to the rate base, a rate-of-return is determined, operating and other expenses are considered, and sales are used to set rates. Although there are important procedural differences between states that rely on historic test years versus future test years for this process, the outcome is similar: rates are established that apply until they are revised.

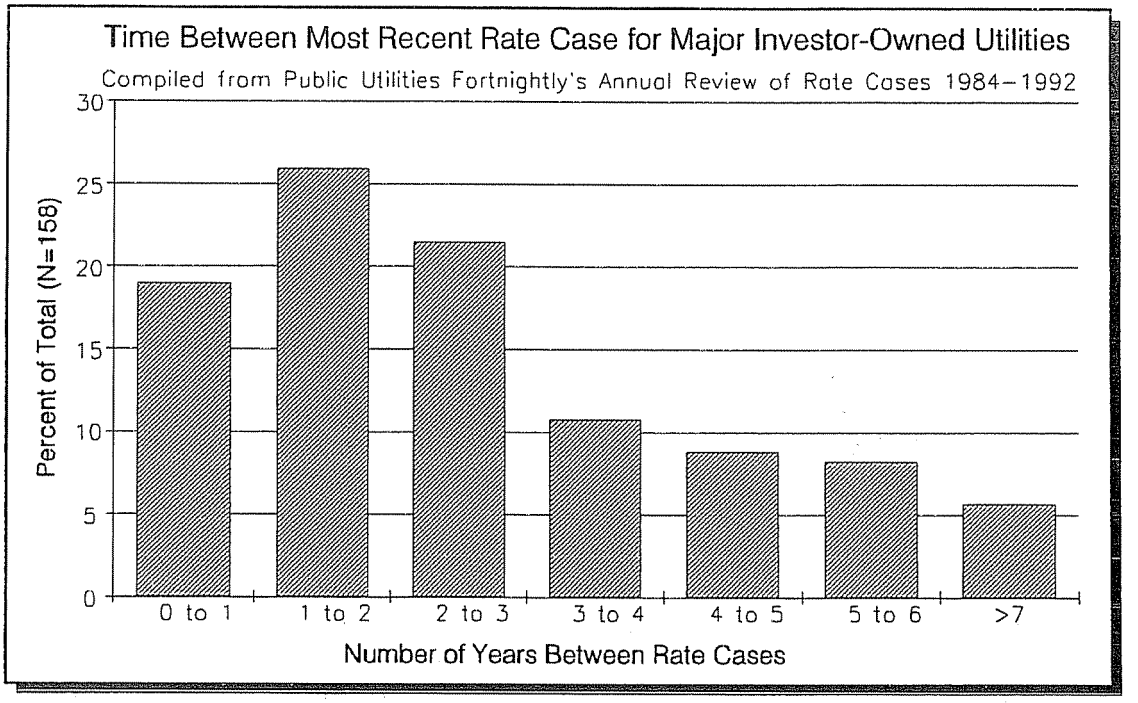
The object of a rate case is to realign the cost relationships that underlie the profitability of incremental sales examined in the previous section. For example, a rate case can prospectively restore earnings opportunities deemed to have fallen inappropriately because of reduced sales or increased costs.

In other words, rate cases act to limit the continuing efficacy of the conditions (described previously) that make incremental sales profitable. In this regard, the profitability of incremental sales appears to be a direct consequence of regulatory lag under the current cost conditions faced by the industry.

Figure 2-2 presents some basic information on the frequency of rate cases. The information was developed by reviewing 10 years of Public Utilities Fortnightly to determine the historic frequency of rate cases. Based on reports for nearly 160 rate cases, we find the average time between rate cases from 1984 to 1992 has been about three years, with the median being slightly less.

The implication for decoupling is clear: if the incentive to sell additional electricity described in the previous section is the primary incentive addressed by decoupling, the importance of decoupling depends on the frequency of rate cases. Because rate cases

Figure 2-2. The Rate Case as a Limit to the Profitability of Sales Increases



can, in principle, fully address all issues underlying the short-run profitability of incremental sales, the value of an additional regulatory intervention, such as decoupling, probably diminishes with increased rate case frequency.

Nevertheless, more frequent rate cases simply to address this aspect of regulatory lag is unlikely to be a viable option because they are time-consuming and expensive to hold. Moreover, to the extent utilities control the timing of rate cases, they may be reluctant to subject all aspects of their business to detailed scrutiny by regulators, particularly so if their business is excessively profitable. Indeed, cost changes that in the past have led to more frequent rate cases have in turn led to the creation of "automatic" adjustment clauses (of which fuel adjustment clauses are the most well-known example), which try to deal directly with specific cost changes, without requiring a rate case. The history of recent regulatory practice has been to create a variety of out-of-rate-case procedures precisely to ensure that rate cases will not be held more frequently. In this regard,

decoupling may be desirable because, to the extent it can successfully address changing costs that would otherwise lead to rate cases, it may delay the need for a rate case.[14]

2.3 The Other Incentive to Sell Electricity

Section 2.1 demonstrated how regulatory lag creates an incentive for incremental sales between rate cases. Section 2.2 identified some of the practical limitations of having more frequent rate cases in order to reduce regulatory lag, thereby creating a role for ratemaking reforms such as decoupling. However, we believe there may be other incentives (and disincentives) for incremental sales that are distinct from that currently created by regulatory lag. Understanding the significance of these incentives is a final threshold issue for decoupling.

Rate-of-return regulation creates a shareholder incentive for utilities to build rate base whenever the rate-of-return exceeds the cost of capital. This feature of regulation is known as the Averch-Johnson thesis.[15] One purpose of the rate case, which recognizes this tendency, is to provide a periodic check on a utilities' activities to ensure that additions to the rate base are prudent. However, the purpose of the rate case is not to question the wisdom of basing utility rates on formulas that link authorized earnings to a fixed percentage of undepreciated assets. If building rate base to meet increased loads leads to increases in authorized revenues and also increases profits, then the basic formulation of rate-of-return regulation creates a distinct incentive for incremental sales.

However, increases in authorized revenues may not translate automatically into increases in profits. Building rate base generally requires new capital. On the one hand, the increased cost of debt may not be fully covered by the authorized increase in earnings. That is, the basic premise of the Averch-Johnson thesis, that the rate-of-return exceeds the cost of capital, may no longer be true. In this situation, if additional shares must be sold to raise capital, shareholder equity will be diluted and, other things being equal, earnings per share will drop. In addition, individual project returns and the size of the firm combine to influence the profitability of individual rate base additions.[16]

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[14] In the Chapter 3, we will describe specifically how decoupling, in fact, leads to reintroduction of some aspects of a rate case because of the way in which it shifts the focus of regulation from rate-setting to revenue-setting. In the Chapters 4 and 5, we will examine how well decoupling deals with cost recovery between rate cases and the resulting effect on profits.

[15] See, for example, Train (1991) for a recent treatment of this topic.

[16] See, for example, Jeynes (1968) for the classic treatment of this topic.

More fundamentally, it also depends on one's view of the future of the investor-owned utility industry. If additions to generating plant cost more than historic average costs, rates will increase. Depending on the options available to utility customers (i.e., their price elasticity of demand), rate increases could have disproportionate effects on future sales and hence earnings. Finally, in world where utilities do very little of the building of new generation, the continuing relevance of an incentive to build load needs to be re-examined.

We cannot treat these issues adequately in the current report. Our point is merely to suggest that there may be other incentives for utilities build load in addition to the one created by regulatory lag. While we have identified rate-of-return regulation as possibly being one such incentive, there are likely to be others. A systematic treatment of decoupling requires, at a minimum, consideration of these incentives. If their influence is small, they may be ignored. If their influence is large, then whether they serve to reinforce or mitigate the incentives created by regulatory lag will become more important.

We show in subsequent chapters that decoupling is, in fact, neutral on the issue of how big the rate base and the sales base that underlies it should be. In this regard, we believe that decoupling is broadly consistent with integrated resource planning because it makes the utility indifferent to incremental sales or losses between rate cases. However, another forum (such as a rate case) must then address the larger questions about the appropriate level of sales and size of the rate base.

2.4 Summary

All firms have an incentive to sell more of their product and a disincentive to sell less whenever the marginal revenue (MR) from a sale exceeds the marginal cost (MC) of production. These conditions (MR > MC) are generally reflective of the current revenue stream and cost structure of most utilities today. For regulated utilities, however, the strength of the incentive to sell and therefore the ability of decoupling to address this incentive depends on other features of regulation. Foremost among these is the frequency of rate cases and the design of fuel adjustment clauses because they directly influence the size and persistence of the disincentives that decoupling seeks to address. At the same time, we also believe there are other incentives (and disincentives) for utilities to build load, which are distinct from the lost revenue problem. Regulatory reforms, therefore, should not focus exclusively on lost revenues, but instead take a broad perspective in trying to align utility incentives with the objectives of integrated resource planning.

Chapter 3

Decoupling Revenue Adjustment Mechanisms

This chapter explains the relationship between traditional utility ratemaking and decoupling. In the first section, we describe the process of establishing a revenue requirement and the setting of rates under traditional rate-of-return regulation. This section includes a discussion of the general rate case, attrition, and automatic adjustment clauses. In the second section, we examine the ways decoupling is used within this traditional process of regulation. We begin by showing how use of a balancing account breaks the link between sales and revenue by ensuring the exact collection of an authorized revenue over time. We then explain how decoupling mechanisms work in conjunction with between-rate-case adjustments to authorized revenues in order to prevent earnings attrition. Finally, we formally define and contrast the decoupling mechanisms that are in use in California, Maine, New York, and Washington.

3.1 Ratemaking Fundamentals

In this section, we describe the general process of ratemaking that is used to regulate electric utilities in most states today. First, we explain how the revenue requirement, allocation of revenue between customer classes, and rate design are determined in a general rate case. Next, we describe how the revenue requirement and rates are adjusted between rate cases through automatic adjustment clauses and attrition hearings. We draw from AGA/EEI *Introduction to Public Utility Accounting* for much of this material (American Gas Association (AGA) 1992). Readers familiar with this subject may wish to skip to 3.2.

3.1.1 The General Rate Case

Test Year

The first step in a general rate case is to develop a representative cost of service that reflects jurisdictional sales, revenues, operating and maintenance expenses, depreciation expenses, income taxes, and return-on-rate base. Although the ratemaking process is forward-looking (i.e., rates are being set to take effect for the year following the rate case), most jurisdictions use a historical test year to calculate the cost of service or revenue requirement. The most commonly identified advantage of the historic test year over a future or forecasted test year is the conservatism inherent in basing future rates

on a known and measurable standard of costs, which of course is most readily documented using recorded costs. However, this advantage is ambiguous because it is customary to adjust recorded figures, in both historic and future test year jurisdictions, to reflect current and expected cost levels and to normalize unusual or erratic expenses.

Revenue Requirement

The different test year costs are combined to develop a revenue requirement. The revenue requirement is defined as:

$$R = OM + Fuel + Capital\,Expenses + Taxes$$

- O&M includes generation, transmission, distribution, and administrative costs.
- Fuel includes fossil fuel, nuclear fuel, water for power, and purchased power expenses.
- Capital expenses include return on rate base and depreciation. Rate base, broadly defined, is the value of used and useful capital assets (after depreciation). The rate-of-return should reflect the cost of the capital that was used to obtain the rate base assets. Depreciation is a non-cash expense that reflects the loss of value of tangible assets over time.

Price

For historic test years, price is calculated by dividing the historic test year's revenue requirement by historic sales.

$$P = \frac{R^h}{Q^h}$$

For utilities that use a future test year, historic values are replaced with forecasts.

$$P = \frac{\hat{R}}{\hat{Q}}$$

The price that is set in the general rate case is used until there is either 1) another general rate case, or 2) a between-rate-case adjustment.

Actual Revenue and Profit

The revenue requirement, defined above, is a hypothetical value that represents the amount of revenue assumed necessary for the utility to cover its expenses and provide a fair return to investors. Actual revenues are a function of price, as established in the general rate case, and actual sales. Accordingly, the revenue requirement and actual revenues will differ to the extent that actual sales differ from the sales quantity used in the general rate case. Profit is equal to actual revenues minus actual expenses.

3.1.2 Between-Rate-Case Adjustments

There are many types of between-rate-case proceedings or regulatory mechanisms that change the revenue requirement and rates. Most of these changes can be classified as automatic adjustment clauses or attrition adjustments. While many states have some form of automatic adjustment clause, substantially fewer states use attrition adjustments.

Generally, an automatic adjustment clause (AAC) is a rate provision which allows a utility: (1) to identify changes in specific operating costs above and below a base cost which is a permanent part of the rate structure; and (2) to pass increases (or decreases) in these costs on to consumers through a surcharge or credit to the bill without complex or time-consuming administrative or legal procedures.

There are two types of automatic adjustment clauses. The first retroactively reconciles *actual* expenditures and revenue. The fuel adjustment clause (FAC) is the most important of this type because it is widely used (in 40 states) and has a large impact on rates. The second type prospectively adjusts rates based on readily available historic or forecast data. Inflation adjustments to O&M expenses fall into this category. Many states have inflation adjustment clauses which update the revenue requirement's O&M expense using some type of regional or national inflation index.

Attrition is "the erosion of earnings that will result when costs are increasing more rapidly than revenues" (Radford 1992). Double-digit inflation and a decreasing rate of sales growth during the 1970's heightened utility interest in between-rate-case financial and operational attrition adjustments. Financial attrition adjustments compensate for increases in capital-related expenses including additions to rate base and higher financing costs. Operational attrition adjustments compensate for increases in operation and maintenance expenses and increased fuel costs (in those jurisdictions without an FAC). Although both types of attrition items were subject to adjustments, the focus of any given attrition adjustment was typically on a single item (unlike a rate case in which all costs are subject to examination).

Attrition adjustments, in those states which permit their use, affect the revenue requirement and rates in much the same way as prospective automatic adjustment clauses. Automatic adjustment clauses are usually specified in advance and based on objective, publicly available information because they are used to track costs which are outside the utility's control and which are known to fluctuate, such as fuel and purchase power costs. In contrast, attrition adjustments require the utility to document the necessity for a change in the revenue requirement.

3.2 Decoupling Revenue Adjustment Mechanisms

Traditional rate-of-return regulation and decoupling use the general rate case and between-rate-case adjustments to establish a revenue requirement. Under traditional ratemaking procedures, the revenue requirement almost always differs from actual revenue because of fluctuations in sales. *Decoupling ensures that actual revenues exactly match an established revenue requirement, regardless of the sales level.* To reflect this important nuance, we refer to the revenue requirement that is established under decoupling as the *authorized revenue.*

Every decoupling Revenue Adjustment Mechanism, or RAM, consists of two parts. First, all decoupling RAMs use balancing accounts to guarantee the exact collection of authorized revenue over time. Second, all decoupling RAMs work in conjunction with an explicit method for changing the level of authorized revenue during years between general rate cases.

3.2.1 Breaking the Link Between Sales and Revenue Using a Balancing Account

The use of a balancing account to ensure exact collection of authorized revenue is consistent in all revenue decoupling RAMs and is central to removing bias against conservation. We begin our explication of the different decoupling RAMs by describing a simplified decoupling mechanism which embodies only this first feature. We assume that this decoupling mechanism, which we call the "Basic" Rate Adjustment Mechanism, operates in a state with a two-year general rate case cycle and no other between-rate-case revenue adjustments. Table 3-1 illustrates the Basic RAM:

The basic RAM requires three sets of numbers to track revenue and price. Columns A-C are established in the general rate case and remain fixed until the next general rate case. Columns D-F represent what actually occurs during each year. Columns G-I represent the numbers that the utility reports in its financial statements (income statement and balance sheet).

Table 3-1. Basic RAM Example

		A	B	C	D	E	F	G	H	I
		Expected Price $/kWh	Expected Sales kWh	Authorized Rev $	Collected Price $/kWh	Collected Sales kWh	Revenue $	Reported Revenue $	+/- $	Balance Account $
GRC 1	Yr 1	0.100	1000	100.00	0.100	1100	110.00	100.00	10.00	(10.00)
	Yr 2	0.100	1000	100.00	0.090	990	89.10	100.00	(10.90)	0.90
GRC 2	Yr 3	0.110	1010	111.10	0.111	1010	112.00	111.10	0.90	0.00

Examining how the numbers change from year to year illustrates how the Basic RAM operates:

Year 1

General Rate Case #1 (GRC 1) authorizes revenue of $100 based on expected sales of 1,000 kWh. During the year, the utility sells 1,100 kWh at $0.10/kWh, resulting in "Collected Revenue" of $110. Basic RAM ensures that the utility can only keep the "Authorized Revenue" of $100. Thus, "Reported Revenue" equals $100 and -$10 is placed into a balancing account. Negative values in the balancing account indicate money that the utility owes the ratepayers (accounts payable); positive values indicate money that ratepayers owe the utility (accounts receivable).

Year 2

Authorized revenue of $100 and expected sales of 1,000 kWh are still in effect from GRC 1. In addition, the utility must "return" $10 to ratepayers from the previous year's overcollection. Accordingly, if the utility collects $90 this year, it will be even with the ratepayers. Thus, the Year 2 Price of $0.09/kWh is calculated by dividing the total revenue that the utility wants to collect ($90) by expected sales (still 1,000 kWh). However, in this case the utility sold less power than expected, resulting in collected revenue of $89.10. The utility still reports revenue of $100, which covers the $89.10 collected from ratepayers this year, the $10 extra that was collected from ratepayers last year, and $0.90 that appears in the balancing account, representing money that the ratepayers owe the utility.

Year 3

As a result of General Rate Case #2 (GRC 2), authorized revenue has increased to $111.10 based on expected sales of 1,010 kWh. In addition, the utility is allowed to collect $0.90 from ratepayers because of the previous year's shortfall. Accordingly, if the utility collects $112 this year, it will be even with the ratepayers. Thus, the Year 3 Price of $0.111/kWh cents is calculated by dividing the total revenue that the utility wants to collect ($112) by the expected sales (now 1,010 kWh). As it turns out, actual sales match expected sales, resulting in collected revenues of $112. The utility reports revenue of $111.10 for Year 3, and the difference in the balancing account ($0.90) means the utility has recovered the previous year's shortfall.

In order to make the Basic RAM simple to understand, we have suppressed the interest component of the balancing account and matched Year 3's expected and actual sales. The balancing account's interest rate is usually pegged to the cost of short-term debt (although some states use the utility's weighted average cost of capital). To the extent that the two rates differ, the utility could be motivated to increase or decrease the decoupling balance. In our analysis, we assume that the interest rate on the balancing account and the cost of funding the balancing account are the same, eliminating the motivation to game the balancing account.

3.2.2 The Need for Changes in Authorized Revenue Between Rate Cases

In our simple example, we showed how balancing accounts ensure that authorized revenues are collected over time. However, in the example we assumed that authorized revenue remained fixed between general rate cases. This is an unrealistic assumption if expenses increase from year to year while revenues remain fixed. As we illustrated in Chapter 2, the problem may become more severe as the time between general rate cases increases. Under traditional rate-of-return regulation, additional revenue associated with increased sales offsets growth in expenses. Decoupling regulations address the problem of increasing expenses by making specific changes to the authorized revenue in years between rate cases. Although balancing accounts operate the same in all decoupling mechanisms, each decoupling mechanism has a unique method for making between-rate-case changes to authorized revenue. These differences are discussed in the next section. In Chapters 4 and 5, we examine the consequences of these differences empirically.

3.3 A Look at Specific Decoupling RAMs

Decoupling Revenue Adjustment Mechanisms are currently used in California, New York, Maine, and Washington. California and New York developed decoupling RAMs that rely on already established procedures for adjusting the revenue requirement between general rate cases. In contrast, Maine and Washington developed new procedures for adjusting authorized revenue between general rate cases. The precise formulation of these procedures is described below.

3.3.1 California ERAM

Revenue decoupling was implemented in California in 1982 by CPUC, Dec. 82-12-055 (California Public Utilities Commission (CPUC) 1981). The stated purpose of California's Electric Revenue Adjustment Mechanism (ERAM) "is to adjust base rate (non-fuel) revenues for changes in revenues due to unexpected fluctuations in sales during the test period." Purported advantages of ERAM include: 1) it affords a utility a better opportunity to earn its authorized rate of return, 2) it eliminates disincentives for the utility to promote conservation, and 3) it stimulates innovative rate design.[17] Currently, all regulated electric and gas utilities in California are subject to ERAM, including Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Electric and Gas (SDG&E), and Southern California Gas (SCG).

California sets rates and revenue using a future test year and a three-year general rate case cycle. Accordingly, the authorized revenue is based on assumptions about what will happen in subsequent years. The following is a definition of authorized revenue, as determined in the triennial general rate case:

$$R^a = \frac{\hat{C}}{\hat{Q}} \cdot \hat{Q} = \hat{C}$$

where R^a indicates authorized revenue, $\hat{C}$ indicates forecast nonfuel cost, and $\hat{Q}$ indicates forecast sales.

When ERAM was implemented, California was already using a variety of between-rate-case revenue adjustment techniques, which it continues to use with ERAM, including an attrition rate adjustment (ARA), cost-of-capital proceedings, and a fuel adjustment clause.

[17] The history, mechanics, and policy issues of California's ERAM have been well documented (Marnay 1990). Our object in this discussion is to review and contrast its specification with other decoupling approaches. In Chapter 6, we summarize the rate impacts of California ERAM.

Under ARA, authorized revenue is escalated using both recorded and forecast escalation factors for labor and nonlabor operation expenses. These escalation factors assume that cost increases associated with sales and customer growth are offset by increased productivity. Additions to the rate base also are addressed by the ARA. Changes in the adopted rate of return are addressed separately in the annual cost of capital proceeding. California also has used a number of ad hoc between-rate-case adjustments associated with major construction projects such as the Diablo Canyon and San Onofre nuclear generating stations.

Rather than develop new methods for adjusting authorized revenue, California's regulators rely on the existing methods for adjusting the revenue requirement. Thus, the authorized revenue for a given year is expressed as

$$R^{at} = \hat{C} + \sum_{t=1}^{n} A$$

where t is the number of years since the last general rate case, n is the total number of years between rate cases, and A includes all adjustments to authorized revenue.

Using information from the balancing account discussion above and our authorized revenue equation, we can now calculate a system average price for a given year:

$$P^t = \frac{R^{at} + B^{t-1}}{\hat{Q}}$$

where P^t indicates price in year t, B^{t-1} indicates the amount in the ERAM balancing account at the end of the previous year, änd $\hat{Q}$is the sales forecast for year t.

3.3.2 New York Revenue Decoupling Mechanism

In 1988, the New York Public Service Commission ordered New York utilities to propose ratemaking innovations that would align the interests of utility shareholders and customers. The Commission's goal was to provide customers with the benefits of least-cost planning and DSM using a mechanism that would also be beneficial to utility shareholders. As part of this reform process, Orange and Rockland adopted an ERAM-like revenue decoupling mechanism (RDM) in 1991 to remove the bias against energy conservation (DiValentino et al. 1992). Since that time, some form of this decoupling has been adopted by all New York utilities, except Central Hudson. Like California, New York is a future-test-year jurisdiction with a tradition of multi-staged revenue filings in which base rates are set and adjusted periodically to reflect changes in specific costs.

RDM was implemented in conjunction with a provision for annual changes in authorized revenue to recover increases in the cost of providing services over a three year rate plan. Adjustments are provided for fuel, operation and maintenance expenses, rate base investment, and the cost of senior capital. Most O&M expenses are subject to an inflation attrition allowance based on a forecast GNP price deflator index. Authorized revenue is updated annually to reflect forecast additions to net utility plant investment and related increases in depreciation. Changes in the utilities' capital structure and cost of debt and preferred stock are updated annually. These changes are reviewed by the New York Public Service Commission through petitions and other required filings.

Although the exact techniques used to adjust authorized revenue are different in New York and California, both provide for between-rate-case adjustments to reflect changes in fuel expenses, O&M expenses, rate base, capital structure, and cost of senior capital. In contrast, California adjusts the adopted return on equity annually while New York fixes it between general rate cases. Despite these differences, the structure of decoupling mechanisms used in the two states is essentially the same.

3.3.3 Maine and Washington Revenue-Per-Customer

In 1991 Puget Power (Moskovitz and Swofford 1991) and Central Maine Power (Goldfard and Spellman 1993) adopted decoupling revenue adjustment mechanisms. According to the agreements authorized by Commissions in Washington and Maine, general rate cases would proceed according to current methods, and the timing of rate cases would continue to be on an "as needed" basis. The new regulations would decouple revenue from sales and recouple revenue to the number of customers. This decoupling revenue adjustment mechanism, called Revenue-Per-Customer (RPC), requires two calculations. First, authorized revenue per customer, which remains fixed until the next general rate case, is computed by dividing allowed revenues (R^h) by the number of customers (N^h), as determined in a historic test-year rate case:

$$RPC^h = \frac{R^h}{N^h}$$

Second, authorized revenue for a given year t is computed by multiplying the authorized revenue per customer times the number of customers (N^t):

$$R^{at} = RPC^h \cdot N^t$$

After each year, the difference between collected revenue and authorized revenue is placed in a balancing account. The following year's rates are adjusted to refund/collect the over/undercollected balance.

Maine and Washington's RPC mechanisms are nearly identical because both decouple revenue from sales and recouple revenue to customers. However, prior to implementing RPC, Puget Power did not have an adjustment clause (with which this hydro-based utility would recover costs for a variety of resources, not only fuel). Now, Puget Power recovers fuel, purchased power (including hydro), and conservation costs through an annual adjustment mechanism that operates in conjunction with RPC. Maine, in contrast, already had a fuel adjustment clause, which remained in effect after the implementation of RPC.

3.4 Summary

In this chapter we have examined differences among traditional rate of return regulation and decoupling mechanisms used in California, Maine, New York, and Washington. The table below identifies important characteristics of each type of regulation.

Table 3-2. Comparison of Ratemaking Approaches

	Decouples Revenue From Sales	Authorized Between-Rate-Case Revenue Adjustments	Fuel Adjustment Clause
Traditional Ratemaking	No	Limited attrition, in a few states	Yes, in most states
California's ERAM	Yes	Detailed attrition procedures	Yes
New York's RDM	Yes	Broad attrition procedures	Yes
Maine's RPC	Yes	# of customers	Yes
Washington's RPC	Yes	# of customers	Yes, reintroduced with RPC

A primary issue for both traditional ratemaking and decoupling is the appropriateness of these explicit and implicit forms of adjusting revenues between rate cases. In Chapters 4 and 5, we will examine the appropriateness of the formal relationships established in this chapter to track non-fuel costs in order to evaluate the consequences of these ratemaking procedures on utility profits.

Chapter 4

Sales Versus Customers as Determinants of Nonfuel Costs

In this chapter, we examine the use of sales versus number of customers as an alternative means for recovering utility costs. In the presence of a fuel adjustment clause, the issue becomes: how closely are changes in nonfuel costs related either to changes in sales (which is how current rate regulation allows utilities to recover these costs) or to some alternative (such as the ones embodied in decoupling mechanisms)? An important issue for RPC is whether recoupling revenues to customer growth improves or reduces a utility's ability to recover these costs (between rate cases) versus the way in which they are recovered under traditional ratemaking. In this chapter, we restrict our focus to the cost-recovery assumptions inherent in traditional ratemaking and RPC decoupling because cost-recovery for California ERAM and New York RDM are linked to attrition mechanisms that have been established separately (and due to their complexity are difficult to evaluate).

The first section of this chapter introduces the data used in our analysis. A more detailed description of the data and its preparation for analysis is presented in Appendix B. In the second section, we present our findings on the ability of changes in sales and customers to explain changes in nonfuel costs. This discussion, however, considers only the ability of one-year changes in load and customers to explain changes in nonfuel costs. Appendix C presents additional exploratory analyses considering different formulations of these explanatory variables, as well as others.[18]

4.1 Aggregate Utility Data on Sales, Customers, and Costs

The U.S. electric power industry is a combination of private, public, cooperative, and federal utilities. Private or investor-owned electric utilities account for more than three-fourths of the revenues and sales in the industry and have historically served large consolidated markets. The Federal Energy Regulatory Commission (FERC) gathers information annually on "major" private electric utilities on Form-1. Major private electric utilities are defined as private utilities that have during the previous past three

[18] In this chapter, we only consider the way in which traditional ratemaking and the RPC decoupling approach allow utilities to recover costs. In Chapter 5, we examine the resulting profit implications of traditional ratemaking and the various decoupling approaches.

consecutive calendar years had sales or transmission services that exceeded one of the following:

- 1 million megawatthours of total annual sales;
- 100 megawatthours of annual sales for resale;
- 500 megawatthours of annual gross interchange out; or
- 500 megawatthours of wheeling for others.

We obtained selected information from Form-1, covering the years 1964 to 1988, for 160 reporting utilities for a total of 3,278 observations. Appendix B provides background on the choice of this data set as well as a description of the steps involved in preparing the data for analysis.

4.1.1 Definition of Sales, Customers, Costs, and Capitalization

In this section, we describe the construction of regression variables used both in this chapter and later in Chapter 5. Although the customer and sales data were readily available, constructing nonfuel cost and capital levels required quite a bit of data manipulation. We used the GDP price deflator found in *The Economic Report of the President - February 1991* to change nominal dollars into real 1982 dollars (Council of Economic Advisors 1992).

Customers and Sales

In our regression models, we use the independent variables "Total Ultimate Customers" and "Total Sales to Ultimate Customers." The following classes are included in this group:

- Residential
- Commercial and Industrial
- Public Street and Highway lighting
- Other to Public Authorities
- Railroads and Railways
- Interdepartmental

NonFuel Costs

Nonfuel costs include operation and maintenance, capital, and tax expenses. Below, we list the major components of each type of expense:

Operation & Maintenance Expense

- Steam power production less fuel
- Nuclear power production less fuel
- Hydraulic power production less water for power
- Other power production less fuel
- Other power supply less purchased power
- Transmission
- Distribution
- Administration

Capital Expense

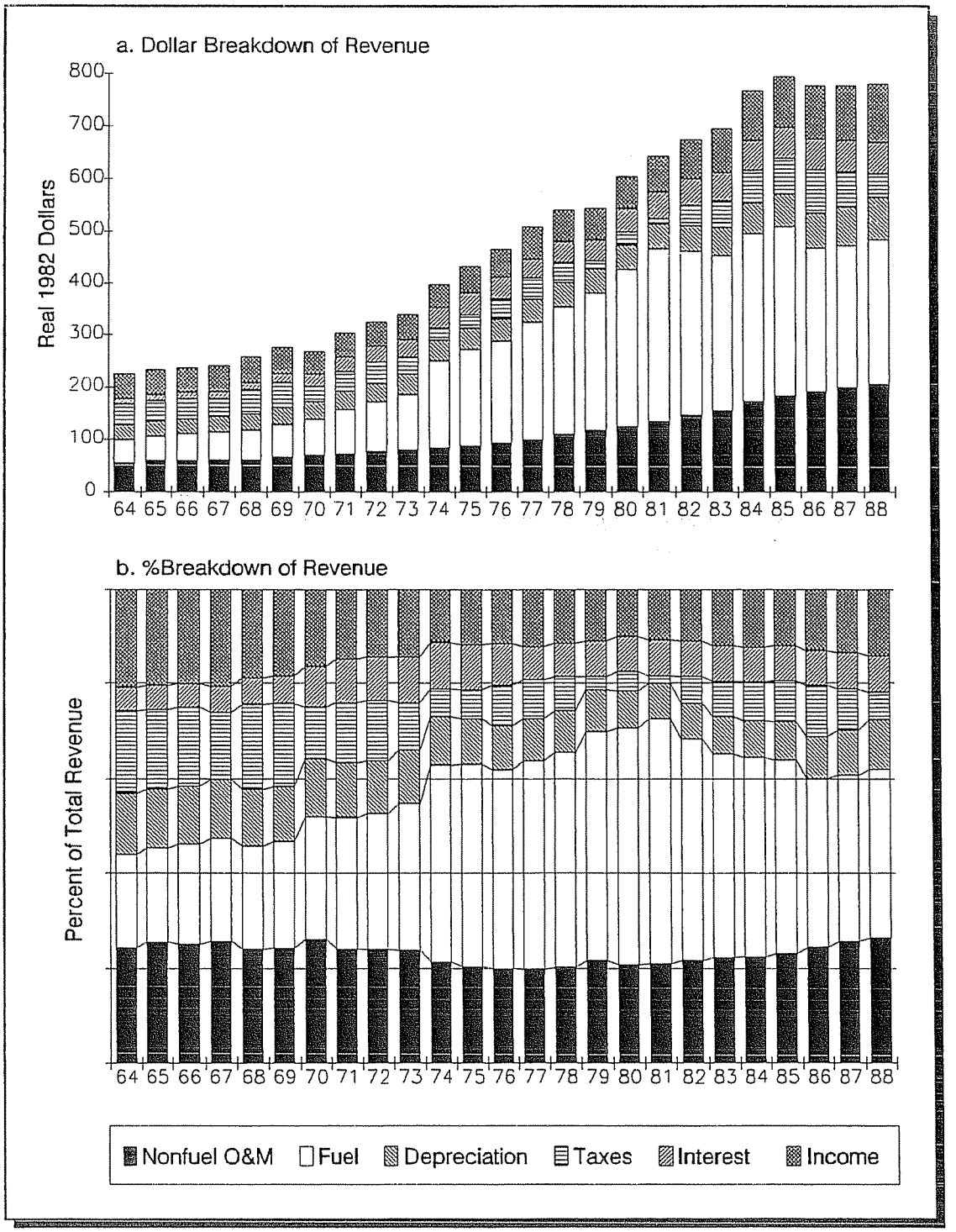
- Net interest charges times the ratio of electric plant to total utility plant
- Preferred stock dividend times the ratio of electric plant to total utility plant
- Common stock dividend times the ratio of electric plant to total utility plant
- Depreciation of electric plant
- Amortization of electric plant
- Taxes

Capitalization

From the balance sheet, we constructed electric utility capital:

- Common stock (book value) times the ratio of electric plant to total utility plant
- Preferred stock (book value) times the ratio of electric plant to total utility plant
- Other Paid-in Capital
- Retained earnings
- Miscellaneous small capital accounts
- Total long-term debt times the ratio of electric plant to total utility plant

Figure 4-1. Uses of Revenue for Major Investor-Owned Electric Utilities



4.1.2 Summary of Data

Figure 4-1 summarizes the aggregate data over time. Nonfuel cost has been split into its major components.

4.2 Regression Analysis of Selected Determinants of Nonfuel Costs

Electric utility regulation implicitly or explicitly establishes relationships among nonfuel costs, sales, and numbers of customers. We have designed several regression models to examine the historic relationship among these three variables. In doing so, we hope to provide insight into how well these relationships correspond to actual utility operation. We begin by formulating algebraically the relationships we will examine statistically. We then report our findings.

4.2.1 Sales and Customers as Determinants of Nonfuel Cost Changes

Traditional ratemaking and the revenue-per-customer decoupling approach can be modeled as

$$R_t = R_h \frac{S_t}{S_h} \quad \text{and} \quad R_t = R_h \frac{N_t}{N_h}$$

where R is revenue, S is sales, and N is the number of customers. The subscript t refers to the current period, while h refers to the test year. Because we believe that both S and N influence nonfuel costs, we need incorporate both into a single equation for purposes of estimation. By algebraically rewriting these relationships, it becomes apparent how to proceed:

$$R_t = R_h + R_h \left[\frac{S_t}{S_h} - 1\right] \quad \text{and} \quad R_t = R_h + R_h \left[\frac{N_t}{N_h} - 1\right]$$

Now we can adjust R_t separately for these two percentage changes. Finally, let us also include the possibility that R_t may be a weighted average of S and N and that R_t may grow autonomously. We now have a more general model:

$$R_t = R_h \cdot \beta^{t-h} + R_h \cdot \beta_1 \left[\frac{S_t}{S_h} - 1\right] + R_h \cdot \beta_2 \left[\frac{N_t}{N_h} - 1\right]$$

which we now simplify to the single period case ($t = h+1$), subtract R_h from both sides, and divide by R_h. Note that the terms in brackets are just the percentage changes in S and N respectively; when $t = h+1$, we will call these $\%\Delta S$ and $\%\Delta N$:

$$\frac{R_t - R_h}{R_h} = \frac{R_h \cdot \beta + R_h \cdot \beta_1 \ \%\Delta S + R_h \cdot \beta_2 \ \%\Delta S - R_h}{R_h}$$

Remembering that nonfuel revenues should equal nonfuel costs because we have defined costs to include the allowed rate of return, we rewrite the last equation in terms of nonfuel cost and add the standard regression error term, ϵ:

$$\%\Delta C = \beta_0 + \beta_1 \cdot \%\Delta S + \beta_2 \cdot \%\Delta N + \epsilon \qquad (4\text{-}1)$$

where $\%\Delta C$ indicates the percentage change in nonfuel cost for one year and $\beta_0 = \beta - 1$.

4.2.2 Regression Results

We now run several regressions, most of which are specific cases of Equation 4-1 above: two with sales, two with customers, and one with both plus an autonomous trend. These help us evaluate traditional ratemaking, RPC, and a final, potentially less biased Revenue Adjustment Mechanism. Each of these regressions is run on approximately 3,300 data points from the FERC data set.

The sales regression yields:

$$\%\Delta C = \underset{(24.5)}{0.399} \cdot \%\Delta S \qquad R^2 = 0.15$$

where the number in parentheses refers to the t-statistic associated with the regression coefficient estimate. This result says that only 40% of a change in sales is correlated with a 100% change in nonfuel costs. This should be compared to traditional ratemaking, which is based on the implicit assumption that

$$\%\Delta C = 1.0 \cdot \%\Delta S$$

which says that every change in sales perfectly (100%) correlates with changes in nonfuel costs. Though it appears that traditional rate regulation provides significant rewards in the short run to utilities that have typical sales growth, this model suppresses any effects of increased sales on long-term costs. (See also Appendix C).

We need to run one more regression with sales in order to find the true incentive for load building. This regression includes an intercept or constant term, as follows:

$$\%\Delta C = \underset{(20.1)}{0.032} + \underset{(4.6)}{0.099} \cdot \%\Delta S \qquad R^2 = 0.01$$

This regression shows that the change in cost of 0.399 $\%\Delta S$ discovered in the previous regression was not caused solely by $\%\Delta S$ but was simply associated with it. Thus, if a utility deliberately achieved a higher $\%\Delta S$, it would probably expect this change to be associated with a cost increase 10% as great instead of 40% as great as the extra change in $\%\Delta S$. Thus, the cost of load-building is quite low, and the compensation from traditional ratemaking is 90% in excess of this cost.[19]

Next, we turn to a regression involving the number of customers, in order to examine the basic assumption underlying the revenue-per-customer decoupling approach. We again begin with the regression without a constant term. The estimated version of this regression is:

$$\%\Delta C = \underset{(23.3)}{0.725} \cdot \%\Delta N \qquad R^2 = 0.14$$

We see that, on average, RPC overrewards by somewhat more than can be observed in the historic data (compare 1.0 to 0.72).

We need to run one more regression with customers in order to find the true relationship between customer and nonfuel cost growth. This regression includes an intercept or constant term, as follows:

$$\%\Delta C = \underset{(22.7)}{0.030} + \underset{(8.5)}{0.294} \cdot \%\Delta N \qquad R^2 = 0.02$$

This second customer regression shows that the change in cost of 0.725 $\%\Delta N$ from the previous regression was mostly not caused by $\%\Delta N$ but was simply associated with it. The cost of serving additional customers is substantially lower, as evidenced by the second regression's coefficient of 0.294 $\%\Delta N$.

Finally, we present a comprehensive regression reflected in Equation 4-1, which considers all three influences simultaneously. In addition to the inclusion of a number of customers and a constant, we specify a sales-related term in the form of sales-per-

[19] Even this estimate of the incentive is too high because we should have looked at the effect of sales-per-customer on costs instead of the effect of sales on costs.

customer (SPC).[20] This regression yields the following coefficients, standard errors and R^2:

$$\%\Delta C = \underset{(18.5)}{0.029} + \underset{(1.6)}{0.035} \cdot \%\Delta SPC + \underset{(8.7)}{0.305} \cdot \%\Delta N \qquad R^2 = 0.02$$

As can be seen, the effect of a 1% change in the number of customers is roughly nine times larger than the effect of a similar change in sales-per-customer (compare 0.305 to 0.035).

Although the effect of customers (compared to sales-per-customers or the constant term) is substantial on average, it is important to note the extremely low R^2 of this regression. Such a low R^2 does not indicate that the effect of customers or sales-per-customer is either poorly estimated or small; instead, it simply indicates that other strong effects have been omitted from our regression. Some of these omitted effects are undoubtedly idiosyncratic, others may be factors that might be addressed explicitly through attrition adjustments (such as interest rates).

Appendix C summarizes additional regression models that further explore effects of sales and customers on nonfuel costs. We also examine the impact of adding attrition-related variables such as capital level, interest rates, and economic growth.

4.3 Summary

Our results show that one-year changes in the number of customers have a fairly strong one-year impact on nonfuel costs but that one-year changes in sales have a rather weak effect. Nevertheless, the results show that, even after accounting for the effects of these two variables and the autonomous trend or constant term, the vast majority of the year-to-year variation in nonfuel costs remain unexplained. In other words, neither the traditional basis for adjusting revenues to account for changes in nonfuel costs nor that embodied in RPC does a very good job of tracking these costs. Between the two approaches, RPC does slightly better.

[20] Simply including sales would be inappropriate because some sales growth is already accounted for by the number of customers. Sales-per-customer allows us to estimate the residual sales-driven costs separately from those that are driven by the number of customers.

Chapter 5

Evaluation of Decoupling Revenue Adjustment Mechanisms

In principle, decoupling should not, solely by its operation, generate earnings beyond those provided for in the rate case. That is, incremental profits should result from increased utility operational efficiencies, rather than from artifacts of the revenue-setting process. In reality, incremental profitability will be determined by how well the revenue-setting mechanism embodied in a decoupling approach tracks underlying cost changes. In Chapter 4, we began investigating this issue by examining how well customer and load growth tracked these costs. In this chapter, we complete our investigation by using the FERC Form-1 data to conduct a controlled experiment measuring the relative, incremental profitability of several alternative decoupling approaches. Similarly, we also examine the historic profitability of California's ERAM.

5.1 Four Decoupling Revenue Adjustment Mechanisms

Decoupling Revenue Adjustment Mechanisms (or RAM's) differ only in their approach to revenue-setting. We consider four approaches: (1) a Basic RAM, without any type of attrition, which will serve as a benchmark;[21] (2) the Revenue-Per-Customer approach or RPC; (3) a hypothetical RAM, based on the final regression presented in Chapter 4, which includes both customers, load-per-customer, and a constant term (called LBL-RAM); and (4) California's ERAM. We also examine a characterization of traditional ratemaking, in which prices are held fixed. Table 5-1 summarizes the differences among the revenue-setting approaches.

5.2 Evaluation of RAM Performance

The incremental profitability of the three hypothetical RAMs and of traditional ratemaking all can be examined systematically using the FERC Form-1 data set. The basic approach is to develop models of the operation of the RAMs, implement them in a standardized fashion, and then calculate the differences between actual and modeled nonfuel revenues.

[21] This simplistic (and highly unlikely) revenue-setting approach was the basis for the example presented in Chapter 3.

Table 5-1. Comparison of Revenue-Setting Approaches

Revenue Adjustment Mechanism	Approach to Setting Revenues
Traditional Ratemaking	C_h/S_h times actual sales
Basic RAM	Authorized Revenue in Test Year
Revenue-Per-Customer	C_h/N_h times actual # of customers
LBL RAM	see equation in text, section 5.2.4
California ERAM	Authorized revenue (test or attrition year)

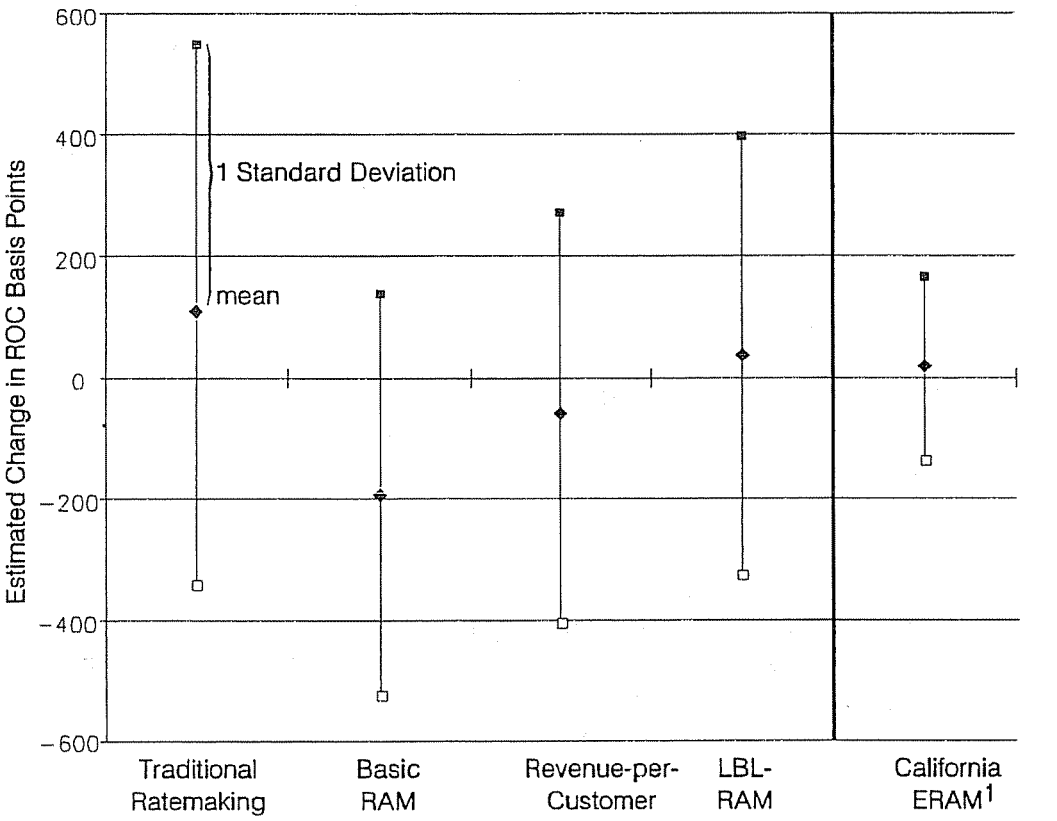
We implement the approach in three steps: First, we pick a historic test year. In that year, we compute the revenue R_h that would be necessary to cover all nonfuel costs C_h, including the allowed rate of return. By including the cost of capital, we have included all economic costs and, therefore, $R_h - C_h$ is equal to economic profit and is zero by definition in the test year. Second, we develop R and C for the following three years, which we fix to be the standardized length of time before the next rate case. Costs for these years are simply those reported in the FERC data set. Revenues are computed to be R_h plus whatever attrition correction is appropriate for the RAM in question. Third, once we have R and C, we compute profit as the difference between the two.

The profit calculated by this approach is properly thought of as incremental profit. It is a (possibly) unintended profit earned, in addition to that established in the rate case, solely as a result of the decoupling revenue-setting process and actual cost changes between rate cases.

We then normalized incremental profit to capital for each revenue-setting approach in order to compare results across utilities and over time. We report both expected profit and the variability of profit. The results are presented in Figure 5-1. The zero line represents the situation in which no excess profits (losses) are earned. It corresponds to a situation in which actual earnings equal those assumed in the rate-setting process.

This general approach was used to evaluate all of the revenue-setting approaches except ERAM. California's ERAM depends crucially on a very complex attrition mechanism which, even if modeled, could not be evaluated with the FERC form 1 data. Consequently we have had to evaluate this type of RAM simply by analyzing its performance when applied to the three California electric utilities for a period of ten

Figure 5-1. Profitability of Traditional Ratemaking and Decoupling Revenue Adjustment Mechanisms



	Traditional Ratemaking	Basic RAM	Revenue-per-Customer	LBL-RAM	California ERAM[1]
Mean	107	-191	-66	36	15
Std Dev	442	328	331	353	144
# of Obs	3,102	3,103	3,102	3,103	32

[1] ERAM values based on ROE

Figure 5-1 depicts expected incremental profit (above or below authorized profit) for each ratemaking scheme. To calculate these values, we simulated the different ratemaking processes using a historic test year and three year rate case cycle. In each case, authorized profit equals zero, reflecting a perfect match between revenue and cost (where cost includes capital expenses). The incremental profit depicted in this figure reflects the theoretical amount of revenue that would be allowed under each ratemaking scheme less actual expenses incurred. The California ERAM results reflect actual authorized revenue and actual expenses.

years. Specifically, the ERAM results are based on actual profit levels. Southern California Edison, San Diego Gas & Electric, and Pacific Gas & Electric provided us with actual and authorized profit from 1983 to 1992, which covers the entire time that ERAM has been in existence. We calculated economic profit by subtracting authorized return on equity, which is determined in annual rate proceedings, from actual return on equity. For California ERAM, we report the average and standard deviation of the 30 economic profit values (three utilities with ten years of performance data). Finally, we were only able to obtain information on return-on-equity. Because capital is larger than equity, the ERAM results presented would probably have a mean even closer to zero, had it been possible to normalize economic profit to capital.

5.2.1 Traditional Ratemaking

Traditional ratemaking holds the nonfuel component of prices fixed between rate cases. To mimic this with FERC data, we compute nonfuel revenue t years after a rate case as follows:

$$R_t = \frac{R_h}{Q_h} Q_t$$

This fixes price at the historic level indicated by the historic test year and produces incremental annual profits of nearly 110 basis points. The fact that profit is consistently high indicates that during this time period costs must on average have been falling relative to prices. This is, in effect, a confirmation that the cost conditions leading to profitable incremental sales (described in Chapter 2) were prevalent during this time period.

Also, as can be seen in Figure 5-1, the variance in profit is the largest of the five revenue-setting approaches considered. The standard deviation is in fact more than four times larger than the estimated positive bias.

5.2.2 Basic RAM

Basic RAM without any form of attrition is even simpler to analyze. It simply sets $R_t = R_h$. This does not allow revenue to increase with either the number of customers, load or with anything else. Because both have increased historically and because they cause cost increases, Basic RAM causes a large profit loss. This loss is estimated to be almost 200 basis points. However, the variance around this result is even greater, although not as large as that found for traditional ratemaking.

This most basic form of a decoupling RAM has not been and is not likely to be implemented, but it is interesting to see why it should not be, and it is useful as a benchmark against which to judge the various RAMs that include explicit revenue adjustments. For example, the result confirms that costs did tend to rise in the period between rate cases. On the other hand, these costs did not rise as fast as marginal revenue under traditional ratemaking.

5.2.3 Revenue-per-Customer

The revenue-per-customer or RPC decoupling revenue adjustment mechanism allows revenues to grow in proportion to the number of customers. Thus, if N_h is the number of customers in the historic test year, and N_t is the number in year t, then

$$R_t = \frac{R_h}{N_h} N_t$$

Notice that this takes the same form as the revenue-setting mechanism used in traditional rate regulation, except that number of customers replaces sales. Because customers seem to have much more of an impact on short-run cost than do sales per customer (see Chapter 4), we would expect this RAM to be only slightly less profitable than traditional rate regulation, which includes both effects. As indicated in Figure 5-1, revenue-per-customer does indeed perform much better than does Basic RAM, producing a profit loss of slightly less than 70 basis points. The variance is comparable to that of the other approaches (except ERAM); in other words, much larger than the negative bias.

5.2.4 LBL RAM

In Chapter 4, we estimated a regression equation that included the combined effects on nonfuel costs of changes in sales per customer and the number of customers. We found that the effect is less than proportional in both cases, so neither traditional ratemaking nor RPC makes an optimal attrition adjustment. That is, from the standpoint of a regression, traditional ratemaking assumes a coefficient on load growth of 1.0 with no constant or intercept term, while RPC assumes a coefficient of 1.0 on customer growth with no intercept. We now construct a RAM that should completely remove the profit bias, and, as a byproduct, should also tend to reduce the variance of profit:

$$R_t = R_h \cdot \left[(1.03)^t + 0.04 \cdot \left(\frac{LPC_t}{LPC_h} - 1\right) + 0.31 \cdot \left(\frac{N_t}{N_h} - 1\right) \right]$$

As can be seen, this RAM also uses a constant exogenous growth rate (or intercept) to help account for nonfuel costs. Figure 5-1 indicates that LBL-RAM has the lowest bias of any of the revenue-setting mechanisms (except ERAM). The incremental profit associated with this approach is less than 40 basis points. Nevertheless, the variance is comparable to that of the other RAMs.

5.2.5 California's ERAM

California's ERAM can be thought of as a basic RAM with a complex nonfuel cost index providing for attrition. Thus, we might write it as:

$$R_t = \frac{R_h}{C_h} C_t$$

where C is the cost index. This does not explain much and, in fact, it is very difficult to give a meaningful quick summary of the attrition adjustment, but it should be noted that the adjustment does take into account the number of customers.[22]

Figure 5-1 shows how ERAM performed between 1983 and 1992 for the three major California electric utilities: PG&E, SDG&E, and SoCal Electric. The attrition approach underlying the ERAM adjustment mechanism appears to measurably reduce the bias and variance, as compared to the other revenue-setting approaches. Nevertheless, there is still a measurable positive bias of approximately 15 basis points.[23]

Bear in mind, however, that the performance of ERAM was calculated in a very different fashion than that used for the other RAMs. These differences severely limit our ability to compare the results of ERAM directly to that of the other RAMs.

5.3 Summary

We saw previously (in Chapter 3) that any RAM, even the most basic, is sufficient to eliminate the utility's incentive to build load.[24] The issue for decoupling is, without the use of load to establish revenues, how should revenues be established? This chapter has

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[22] Marnay (1990) describes the elements of California's attrition in great detail.

[23] As noted previously (in Section 5.2), since we were able to estimate the profitability of ERAM based only on return on equity, so we believe the estimated bias is higher than it would be if we had used return on capital.

[24] This is true when load is not one of the variables used to set authorized revenues between rate cases.

considered this issue from the standpoint of the bias and variability of incremental profits resulting from adoption of several revenue-setting approaches. The results were developed using a standardized procedure that allowed comparison to traditional ratemaking.

We first demonstrated that the most basic RAM, without any attrition mechanism, introduces a significant downward bias in profit. Any of several attrition alternatives can greatly reduce this bias, but they must contain some adjustment for customer growth. We also found that our characterization of traditional ratemaking, which adjusts revenues in direct proportion to sales, also led to a reduction in bias. Finally, although correcting for customer growth is sufficient to eliminate most of the bias introduced by a basic RAM, it is does not eliminate much of the variance in profit that is present with or without a RAM.

All of the results were subject to wide variability. The smallest variability was observed in the historic performance of California's ERAM. This finding, with some qualifications, should not be surprising because the attrition adjustments underlying California's ERAM are very disaggregated and complex while the equivalent adjustments we have considered were restricted to sales, customers, and an exogenous trend or constant term. One would expect a more detailed tracking of components of nonfuel costs (that also includes customer growth) would perform more accurately than an aggregate tracking of these costs based only on sales or customer growth.

More importantly, the variance we observe in these results is much greater than is the tendency of a given approach to bias profits in a particular direction. In other words, other factors, such as business practices, other regulations, and the general business climate, will likely have a greater influence on profits than will these specific ratemaking approaches.

Chapter 6

The Historic Rate Impacts of ERAM in California

Much of the current controversy surrounding decoupling has centered on its rate impacts, which arise as a consequence of the balancing account required to implement decoupling. The issues range from philosophical implications of risk-shifting to pragmatic concerns regarding the magnitude of the accrued balances and their potentially dramatic impacts on rates. The goal of this chapter is to provide a context for these discussions by introducing the historic record of decoupling from the state with the longest experience with decoupling, California. Appendix D continues this discussion with a theoretical quantification of the risk-shifting implications of decoupling.

6.1 Tracing the History of ERAM in California

As has been well-documented in Marnay and Comnes (1990), California ratemaking is a complicated process. Rates are adjusted both through triennial general rate cases (GRC) and through a variety of annual adjustments, of which ERAM is only one. Annually, there is also a fuel adjustment clause (referred to as the Energy Cost Adjustment Clause) and an attrition adjustment, in addition to several other less-well-known or less-systematically-used adjustments. Retail rates reflect the net impact of all of these adjustments.

The primary challenge for documenting the rate impacts of ERAM was identification of a consistent set of records. We ultimately determined that, wherever possible, we would rely on publicly available rate decisions on file at the California Public Utilities Commission (CPUC). Nevertheless, we were not able to locate decisions for several years and thus have relied on company-supplied data in some cases.

We obtained revenue requirement and rate data for California's utilities for the entire time that ERAM has been in effect. For Pacific Gas & Electric (PG&E), the data for 1982 to 1991 were contained in 13 CPUC decisions. Data for 1992 and 1993 were provided by the company. For Southern California Edison (SCE), the data for 1983 to

1993 were contained in 15 CPUC decisions.[25] For San Diego Gas & Electric (SDG&E), the data for 1982 to 1992 were contained in 13 CPUC decisions.

6.2 California Electricity Rate History

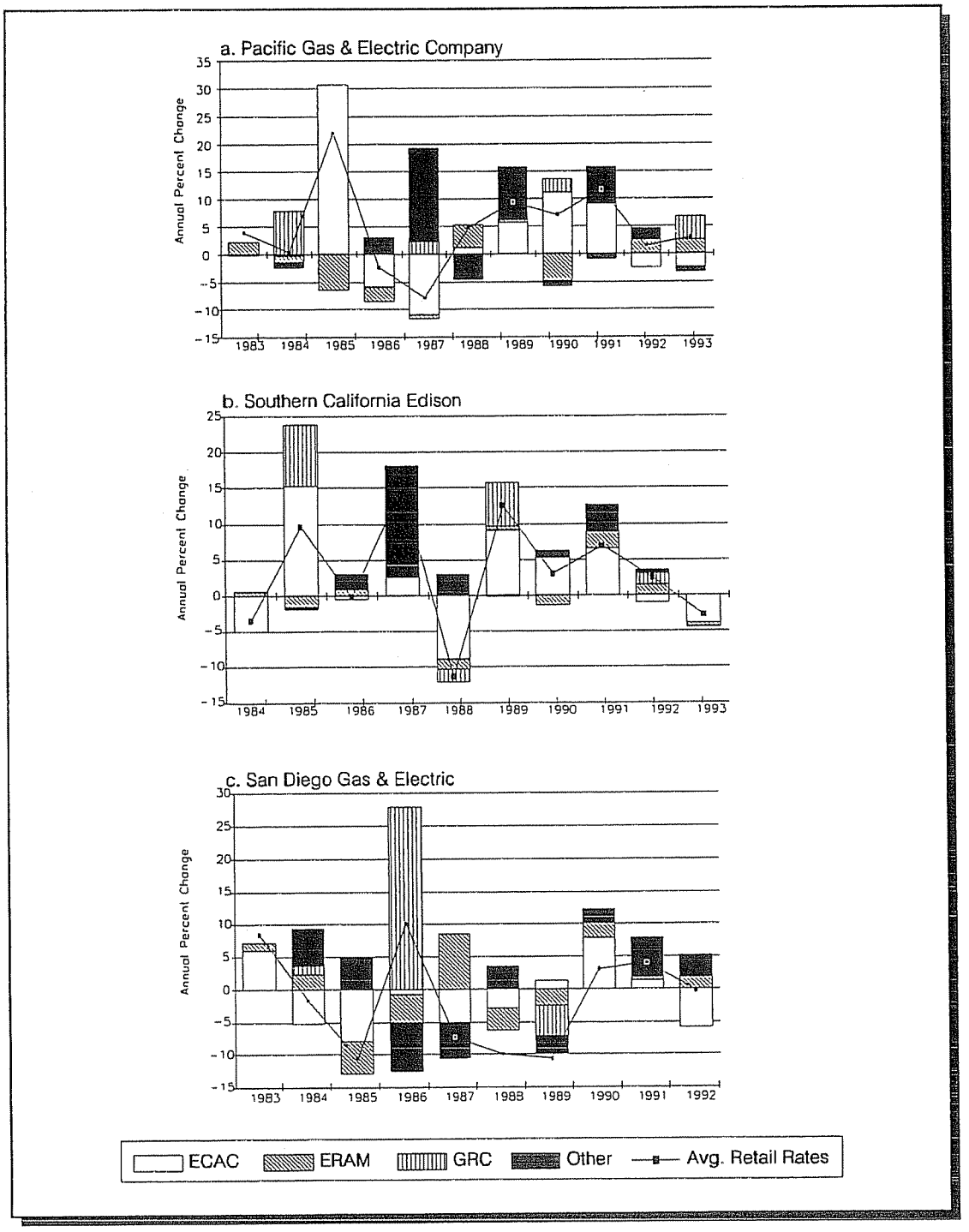
In the first stage of our review, we disaggregated the rate history of each utility into four categories of adjustments to overall revenue requirements: ECAC, ERAM, general rate case, and other. ECAC, California's fuel adjustment clause, consists primarily of fuel cost changes resulting from retroactive adjustments that "true-up" previous miscollections and prospective adjustments that are based on expected future fuel expenditures. ECAC also includes payments to QFs and recovery of utility DSM incentives. The ERAM balance should only contain income from sales-related mismatches between authorized revenues and actual revenues collected. In many cases, the ERAM balance included items not related to over or undercollections resulting from sales fluctuations. Usually, we were able to identify these other items and move them from the ERAM category to the "other" category. The general rate case (GRC) includes nonfuel revenue changes that are determined in those years when a complete rate case was held. The other category includes a wide range of revenue requirement changes. Attrition adjustments represent much of this category. However, there are many one-time adjustments that relate to particular construction projects or changes in tax laws included in this category.

Figure 6-1 shows changes in revenue requirements and retail rates from 1983 to 1993, for PG&E, SCE, and SDG&E, respectively. Note that the net effect of positive and negative revenue requirement adjustments does not equal the change in retail rates. The reason for this difference is that the sales forecast also changes in the annual adjustments.

The data clearly indicate that, in the overall context of California ratemaking, the clearing of ERAM balances has accounted for only a small proportion of the total change in revenue requirements in the last 10 years. Adjustments resulting from ECAC have been, by far, the dominant source of changes to revenue requirements. The compound effect of multiple, annual adjustments to revenue requirements is highlighted by the relatively small role played by the GRC in adjusting revenue requirements.

[25] In 1987 SCE implemented a series of offsetting revenue requirement adjustments that had no impact on rates. These adjustments, which included $11.5 million in increases and $11.5 million in decreases, pertained to the phase-in of the Palo Verde nuclear plant, ERAM, and other rate base adjustments. We were unable to separate these offsetting changes into the appropriate rate categories.

Figure 6-1. Changes in Authorized Revenue Requirement and Average Retail Rates



6.3 Electricity Rate Changes With and Without ERAM

The annual rate changes depicted in Figure 6-1 include ERAM adjustments to revenue requirements. In order to determine the effect of ERAM on rates, we also compared the actual rates, as reported above, to hypothetical rates, which exclude ERAM. To do this, we subtracted the ERAM balance from each year's revenue requirement and divided by authorized sales.[26] Figure 6-2 shows annual changes in retail rate levels, both with and without the ERAM, for PG&E, SCE, and SDG&E, respectively. Table 6-1 summarizes these findings.

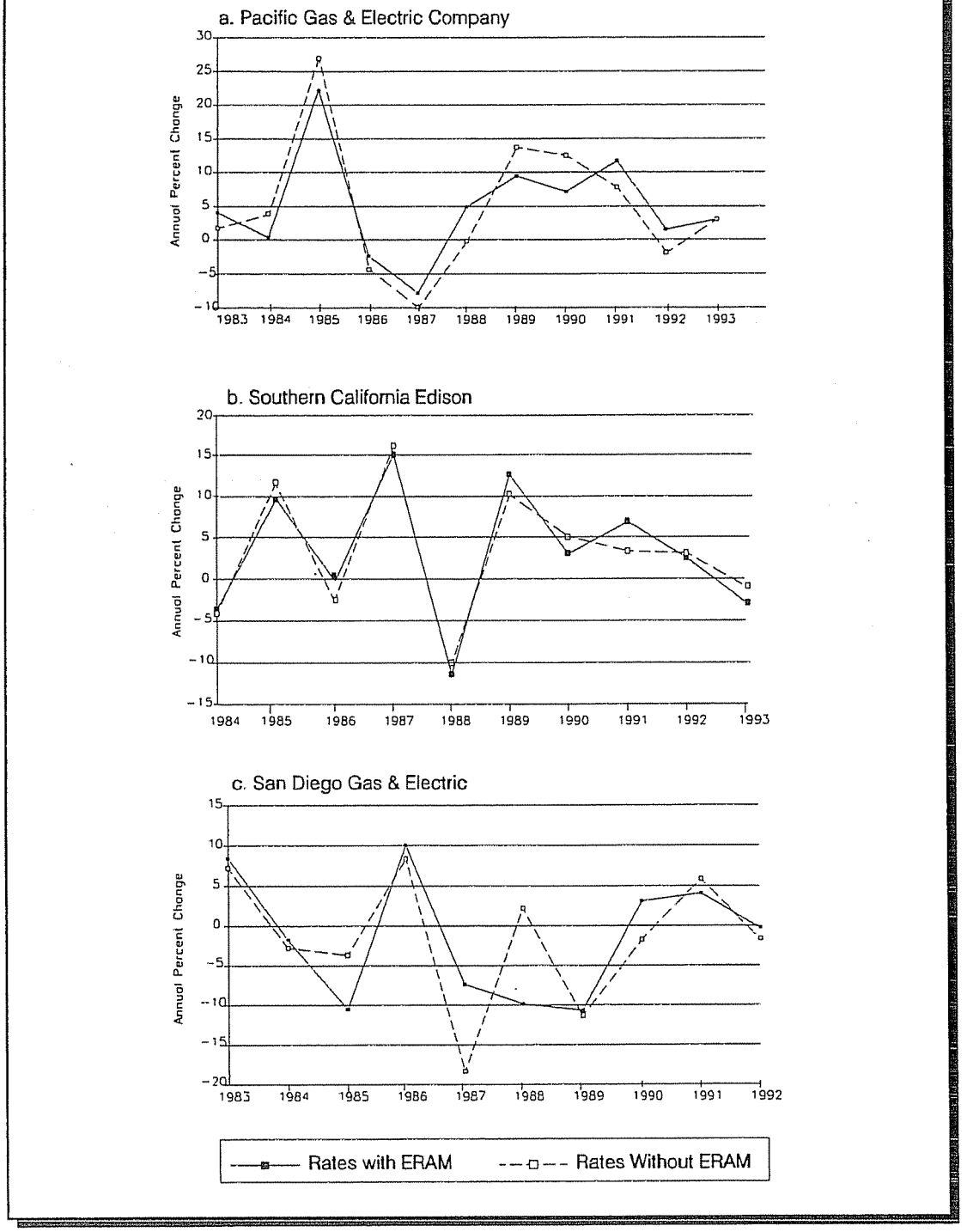
Table 6-1. Annual Percent Changes in Revenue Requirement and Retail Rates

	PG&E			SCE			SDG&E		
	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)	Rev. Req. (%)	Rates w/ ERAM (%)	Rates w/o ERAM (%)
1983	2.0	4.0	1.7				7.3	8.4	7.2
1984	5.3	0.4	3.8	-4.4	-3.5	-4.0	4.0	-1.7	-2.7
1985	24.3	22.1	26.9	21.8	9.6	11.7	-7.9	-10.5	-3.7
1986	-5.6	-2.4	-4.3	2.5	-0.2	-2.3	15.2	10.1	8.3
1987	7.6	-7.9	-10.0	18.1	15.1	16.1	-2.2	-7.3	-18.3
1988	0.7	4.8	-0.2	-9.2	-11.5	-10.0	-2.9	-9.9	2.1
1989	15.9	9.4	13.7	15.5	12.6	10.2	-8.8	-10.7	-11.4
1990	7.7	7.1	12.5	4.8	3.0	5.1	12.4	3.1	-1.7
1991	14.8	11.7	7.8	12.7	6.9	3.4	7.9	4.0	5.8
1992	2.2	1.5	-1.9	2.4	2.5	3.1	-0.8	-0.3	-1.7
1993	3.5	3.0	3.0	-4.6	-2.8	-0.9			
Mean	7.1	4.9	4.8	6.0	3.2	3.2	2.4	-1.5	-1.6
Std. Dev.	8.0	7.5	9.6	10.1	7.7	7.5	7.8	7.4	7.9

The data indicate that, just as the magnitude of the ERAM adjustments has been a small factor influencing changes to authorized revenues, the rate impacts of ERAM have also

[26] This approach to measuring the effect of ERAM on rates assumes that, without ERAM, the monies accrued in the ERAM balancing account would not otherwise be recognized through some other revenue adjustment, such as attrition or more frequent rate cases.

Figure 6-2. Changes in Average Retail Rates With and Without ERAM



been small. For PG&E, ERAM adjustments actually reduced rate volatility, as evidenced by a reduction in the standard deviation of annual rate changes from 9.6% to 7.5%. For SCE and SDG&E, ERAM has contributed little additional volatility to rates.

6.4 Has ERAM Shifted Rate Risk?

The typical argument for the existence of rate risk-shifting asserts that if demand is unexpectedly low and, through decoupling, the utility does not suffer from lost revenues because rates are raised, customers will bear the burden of higher rates. What this argument neglects is the correlation, or lack thereof, between rate fluctuation caused by decoupling and those fluctuations that are already present in the absence of decoupling. If this correlation happens to be greater than zero, then risks are being shifted; if this correlation is less than zero, then decoupling will actually reduce customer risk (i.e. increase customer utility assuming no bias). The magnitude of the correlation indicates the degree of transfer.

In the case of California's ERAM, we have estimated a decrease in the standard deviation of the utility's profit from about 4.4% to about 1.4% because of ERAM (see Chapter 5). Accompanying this, we have also estimated a decrease in the standard deviation of annual rate changes for two utilities (for PG&E, 9.5% to 7.5%; for SDG&E, 7.9% to 7.4%). Based on these estimates, we should conclude that for these two California utilities, there has been no risk shifting at all. Instead, ERAM has been accompanied by rate risk reductions to customers and profit risk reductions to utilities.

Of course, California's experience with ERAM cannot be generalized. In Appendix D, we continue this line of inquiry with a estimation of the cost of risk shifting using examples in which there has been some transfer of risk.

6.5 Summary

The history of decoupling in California suggests that: (1) decoupling has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility; (2) in terms of decoupling's relative impact, the rate changes resulting from the fuel adjustment clause have had far more dramatic effects on rates and, consequently, on the shifting of business risk from utility shareholders to utility ratepayers; and (3) when combined with our profitability analysis in Chapter 5, ERAM has, in fact, not been accompanied by any risk shifting at all for two of California's utilities. Thus, the larger issue for utility policy is that, in considering rate risk allocation and rate volatility issues, it is more appropriate

to consider decoupling in the context of a comprehensive framework that jointly considers all sources of rate risk and rate volatility.[27]

[27] Appendix D discusses ERAM rate risk reallocation between shareholders and ratepayers.

Chapter 7

Conclusions

We believe there are three issues for utilities and regulators who are considering decoupling. First, the importance of lost revenues and therefore of decoupling depends strongly on pre-existing features of regulation. Notably, the frequency of rate cases and the design of fuel adjustment clauses directly influence the size and persistence of the disincentives that decoupling seeks to address. At the same time, we also believe there are other incentives (and disincentives) for utilities to build load, which are distinct from the lost revenue problem. Regulatory reforms, therefore, should not focus exclusively on lost revenues, but instead take a broad perspective in trying to align utility incentives with the objectives of integrated resource planning.

Second, adoption of a decoupling mechanism requires consideration of the means by which revenues are set between rate cases, especially accounting for changes in nonfuel costs. Our examination of the empirical record suggests that, over short periods of time, neither load growth (which underlies traditional ratemaking) nor customer growth (which underlies RPC) provide a very powerful basis for explaining changes in these costs. In other words, the revenue-per-customer approach (in addition to decoupling sales from revenues) will on average do no worse than traditional ratemaking in tracking these costs. Thus, if cost-tracking is an important ratemaking objective, it is a separable concern from decoupling for which other approaches should be considered, such as attrition mechanisms or future test years.

Third, the record in California suggests that the issue of the additional rate volatility introduced by decoupling has been overemphasized. We believe that discussions of the additional rate volatility and risk-shifting associated with decoupling should be conducted in a framework that considers all sources of rate volatility and risk-shifting in ratemaking. In this framework, the questions of what the risks are and who is best suited to bear them can be made explicit and their treatment made comprehensive, rather than piecemeal.

Decoupling can play an important role in transforming utilities from sellers of a least-cost energy commodity to providers of least-cost energy services, but it is no panacea. While it can successfully eliminate an important disincentive for utility DSM programs, it must be designed carefully to take explicit account of other regulatory objectives, such as cost-tracking and rate volatility.

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Appendix A

Calculating the Profitability of Incremental Sales

This Appendix supplements the discussions in Chapter 2 with the derivation of algebraic relationships among: (1) the magnitude of the variable cost elements affected by a sales increase as a fraction of total *(X)*; (2) the marginal rate at which the variable cost elements change with respect to the average rate of variable cost changes *(Y)*; (3) the initial profit margin *(Z)*; and (4) profits. We begin with the basic definition of profit:

$$\pi = R - C$$

R is revenue, C is costs, and the difference, π, is profit. Revenue is simply sales *(S)* times price (P_0), which is assumed to remain fixed:

$$R = S \times P_0$$

Costs *(C)* can be thought of as having both a fixed *(FC)* and a variable *(VC)* component:

$$C = FC + VC$$

Furthermore, in the base case, there is a fixed relationship between these costs, defined by *X*:

$$X = \frac{VC_0}{FC_0 + VC_0}$$

Now, introduce *Y*, which is the ratio of marginal variable costs to average variable costs, to account for the change in variable costs *(VC)* with respect to a sales quantity, *S*, that is different from that in the base case *(S_0)*:

$$Y = \frac{\frac{VC - VC_0}{S - S_0}}{\frac{VC_0}{S_0}}$$

The cost equation can now be written as:

$$C = [\frac{VC_0}{X} - VC_0] + [VC_0 + \frac{VC_0}{S_0} \times Y \times (S_0 - S)]$$

Of course, in the base case (where S equals S_0), this equation reduces to:

$$C_0 = \frac{VC_0}{X}$$

Now, let Z equal the initial profit margin:

$$Z = 1 - \frac{C_0}{R_0}$$

which can be solved for P_0:

$$P_0 = \frac{VC_0}{S_0 \times X \times (1 - Z)}$$

The profitability equation can now be written as:

$$\pi = [S \times \frac{VC_0}{S_0 \times X \times (1 - Z)}] - [\frac{VC_0}{X} + \frac{VC_0}{S_0} \times Y \times (S - S_0)]$$

We are interested in the change in profit due to a change in sales:

$$\frac{\pi - \pi_0}{\pi_0} = \frac{[S \times \frac{VC_0}{S_0 \times X \times (1 - Z)} - \frac{VC_0}{X} - \frac{VC_0}{S_0} \times Y \times (S - S_0)] - [S_0 \times \frac{VC_0}{S_0 \times X \times (1 - Z)} - \frac{VC_0}{X}]}{[S_0 \times \frac{VC_0}{S_0 \times X \times (1 - Z)} - \frac{VC_0}{X}]}$$

Re-arranging terms yields:

$$\frac{\pi - \pi_0}{\pi_0} = \frac{S - S_0}{S} \times \frac{1 - Y \times X \times (1 - Z)}{Z}$$

This relationship was used to develop Figure 2-1.

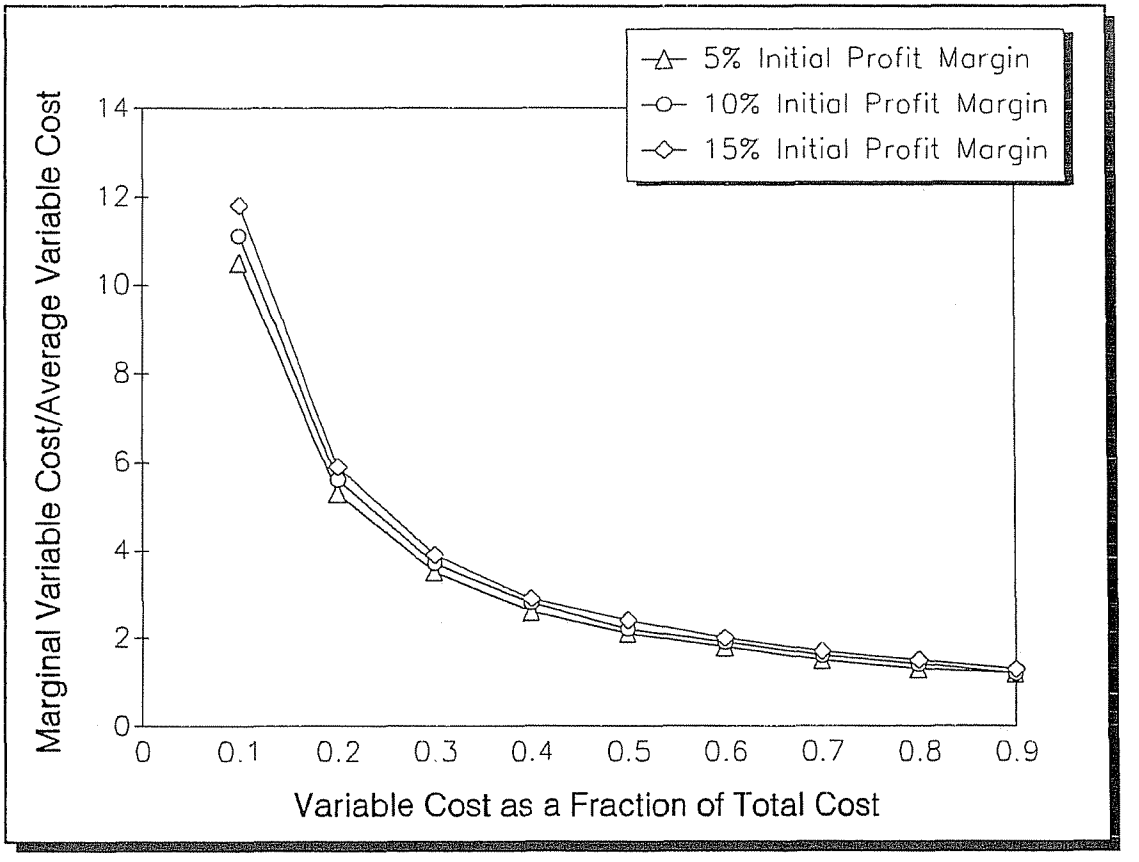
We can also readily solve for the "break-even" condition in which there is no change in profit:

$$1 = X \times Y \times (1 - Z)$$

This relationship is summarized graphically in Figure A-1. Figure A-1 plots, for a range of variable costs expressed as a fraction of total costs, the size of the change required to eliminate all additional profits from the sales increase.

Considering the base situation presented in Chapter 2, in which 80% of total costs were assumed to be influenced by changes in sales, Figure A-1 indicates that the marginal change or responsiveness of these costs to the sales increase would have to be about 2.0 (in other words, a 1% increase in sales must correspond to a 2% increase in affected variable costs) in order to eliminate an increase in profits from the starting situation. As variable costs become a smaller fraction of total costs, the marginal change must be very large in order to offset an increase in profits. Figure A-1 indicates also that, for different initial profit margins, these conditions change only slightly as variable costs become a smaller fraction of total costs.

Figure A-1. Break-Even Profitability for a 1% Increase in Sales



Appendix B

Discussion of FERC Form-1 Data

This appendix describes the data selection and screening process. We begin by defining the requirements that our data set had to meet in order to perform the regressions reported in Chapter 4 and Appendix C. Next, we describe the process used to screen the data, in order to limit the data set to only those utilities for which traditional retail ratemaking and decoupling were designed. Then, we list the individual utilities used in the analysis. Finally, we present summary operating statistics calculated using the FERC Form-1 data.

B.1 Selecting a Data Source

The two main criteria for selecting data for this project were that the data had to be national in scope and contain the variables necessary to evaluate the revenue adjustment mechanisms defined in Chapter 3. These variables include nonfuel cost, depreciation expense, return on rate base, equity capital, debt capital, sales, and customers.

We considered two sources of data: the U.S. Energy Information Administration (EIA) and the Edison Electric Institute (EEI). EIA conducts an annual survey of investor-owned utilities and publishes the findings in *Financial Statistics of Selected Electric Utilities* and on computer tape. Federal law requires utilities to file this information, which is collected using FERC Form-1. EEI gathers similar data and publishes the *Statistical Yearbook of the Electric Utility Industry*. Reporting is voluntary, and the data are not readily available on computer tape. Accordingly, we chose to use the FERC Form-1 data.

The U.S. electric power industry is a combination of private, public, cooperative, and federal utilities. Private or investor-owned electric utilities account for more than three-fourths of the revenues and sales in the industry, historically serving large consolidated markets. The Federal Energy Regulatory Commission (FERC) gathers information on "major" private electric utilities on Form-1. Major private electric utilities are defined as private utilities that have had during the past three consecutive calendar years, sales or transmission services that exceeded one of the following:

- 1 million megawatthours of total annual sales
- 100 megawatthours of annual sales for resale

- 500 megawatthours of annual gross interchange out
- 500 megawatthours of wheeling for others

B.2 Screening the Data

We developed a four-step screening process to ensure data quality. First, we limited the data set to the types of utilities for which traditional retail ratemaking and decoupling were designed. That is, we eliminated utilities whose primary business is wheeling or wholesale power. Second, we identified and removed erroneous data. Third, we eliminated data that we could not use because accounting conventions resulted in negative nonfuel costs. Finally, we eliminated an observation if nonfuel costs changed by 30% or more in one year. These steps are now briefly summarized.

The regulations that we evaluate are designed for utilities that provide comprehensive electric services to ultimate customers. We screened the data to retain only those utilities whose primary operation and source of revenue is from sales to ultimate customers. In order for a utility to pass this screening process, it must have:

- at least 1,000 ultimate customers
- at least 100,000 kWh of annual generation
- Power production expense
- Transmission expense
- Distribution expense
- Customer Service expense

This eliminated 89 utilities, representing 1,395 observations.

Next, we developed a system for identifying bad data. Missing values are one type of bad data. The FERC Form-1 tapes did not contain missing value indicators; however, by careful study of the data we were able to identify some zero entries as corresponding to missing values. Eleven observations were eliminated because of missing values. We also found instances where a utility had consistent values for a certain variable in every year except one or two. This eliminated 31 more observations.

We also eliminated data when accounting conventions made it impossible to calculate a meaningful nonfuel cost. Large credits in operation and maintenance expense accounts sometimes resulted in negative nonfuel production expenses. This is because the FERC standard set of accounts defines revenue from steam transfer, rent, and miscellaneous other power as a contra-expenses. This eliminated 97 observations.

We decided to eliminate a utility in a given year if it reported a large change in nonfuel costs. There are two reasons for this. First, we wanted to eliminate the effect of utility mergers on our regression results. There were several mergers between 1964 and 1988 which resulted in dramatic, one-year increases in customers, sales, and nonfuel costs. Second, the goal of our regression analysis was to examine the relationship among customers, sales, and nonfuel expenses under normal operating conditions. Defining normal operating conditions is a subjective process. Ultimately, we eliminated observations where nonfuel costs changed by 30% or more in one year. However, it should be noted that the regression results were similar when we truncated at 10%, 30%, or 50% changes in nonfuel costs. This eliminated 235 observations.

After completing the screening, our data set consisted of 3,278 observations representing 160 utilities. A list of company names and years of data used in our analysis is reported in Table B-1.

Table B-1. Utilities and Reporting Years Used in LBL Analysis

Alabama Power Company (71,74,75,78-88)
Arizona Public Service Company (65-71,74-84,87)
Citizens Utilities (68,70-88)
Arkansas Missouri Power (65-80)
Arkansas Power & Light (65-85,88)
Pacific Gas & Electric (65-88)
San Diego Gas & Electric (65-88)
Southern California Edison (65-82,84-88)
Public Service Company of Colorado (65-88)
Connecticut Light & Power (67-81,83-88)
Hartford Electric Light (65-81)
United Illuminating (65-88)
Delaware Power & Light (65-88)
Potomac Electric Power (65-88)
Florida Power (65-88)
Florida Power & Light (65-88)
Florida Public Utilities (65-86)
Gulf Power (65-88)
Tampa Electric (65-88)
Georgia Power (65-88)
Savannah Electric & Power (65-88)
Hawaiian Electric (65-88)
Hilo Electric Light (65-69,80-83)
Kauai Electric (65-68)
Maui Electric (65-69,80-83,86)
Idaho Power (65-77,80-88)
Central Illinois Electric & Gas (65,66)
Central Illinois Light (65-88)
Central Illinois Public Service (65-88)
Commonwealth Edison (65-88)
Illinois Power (65-88)
Mt. Carmel Public Utility (65-88)
Indiana & Michigan Electric (65-78,80-88)
Indianapolis Power & Light (65-88)
Northern Indiana Public Service (65-85,88)
Public Service Company of Indiana (65-85)
Southern Indiana Gas & Electric (65-88)
Interstate Power (65-88)
Iowa Electric Light & Power (65-88)
Iowa Illinois Gas & Electric (65-88)
Iowa Power & Light (65-88)
Iowa Public Service (65-88)
Iowa Southern Utilities (65-81,84-88)
Central Kansas Power (65-74)
Central Telephone & Utilities (69-88)
Kansas Gas & Electric (65-88)
Kansas Power & Light (67-88)
Western Power & Gas (66,67)
Kentucky Power (65-69,73-88)
Kentucky Utilities (65-88)
Louisville Gas & Electric (65-88)
Central Louisiana Electric (65-88)
Gulf States Utilities (69-71,74-86)
Louisiana Power & Light (65-85,88)
New Orleans Public Service (65-84)
Peoples Utilities (66)
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Appendix C

Discussion of Statistical Analysis

This appendix describes additional statistical analyses performed using FERC Form-1 data. We begin by summarizing the regressions models described in Chapter 4, which included cost, sales, and customer variables. These models provided the basis for our evaluation of different revenue adjustment mechanisms in Chapter 5. We then introduce three extensions to the Chapter 4 models. First, we added variables to our original model to the see if we could improve its explanatory power. Second, we examined changes in capital and customers over several years to determine whether a time lag exists between an increase in the independent variables, capital and customers, and an increase in nonfuel costs. Third, we tried to distinguish between expected and unexpected changes in sales growth.

C.1 Cost, Sales, and Customers

We begin this discussion by presenting the non-fuel cost, sales, and customer regression models from Chapter 4. These models examine the relationship between changes in nonfuel costs and changes in sales and customers. First, we regressed changes in nonfuel costs on changes in sales and customers separately:

$$\%\Delta C = \underset{(.016)}{0.399} \cdot \%\Delta S \qquad R^2 = 0.15$$

$$\%\Delta C = \underset{(0.03)}{0.72} \cdot \%\Delta N \qquad R^2 = 0.14$$

Then, we constructed a model that would capture the effect of changes in sales and customers simultaneously. In this model, we specify a sales-related term in the form of sales-per-customer. Simply including sales would be inappropriate because some sales growth is already accounted for by the number of customers. Sales-per-customer allows us to estimate the residual sales-driven costs separately from those that are driven by the number of customers. In addition, we added an intercept term, which captures changes in costs that are not related to sales or the number of customers.

$$\%\Delta C = \underset{(0.002)}{0.029} + \underset{(0.023)}{0.035} \cdot \%\Delta LPC + \underset{(0.035)}{0.305} \cdot \%\Delta N \qquad R^2 = 0.02$$

C.2 Additional Variables

Clearly, neither changes in sales nor customers explains a significant amount of the changes in non-fuel cost, as evidenced by the low R^2 terms. We tried other formulations of the basic sales and customer models to identify other variables that may have a significant effect on changes in cost. Many attrition proceedings adjust rates based on changes in capital levels and interest rates. We added these variables to our model, using company-specific capital levels and the average annual interest rate of AAA bonds. We also included a variable for annual changes in U.S. gross domestic product.

Table C-1. "Stepwise" Regression Results

	Intercept	% Δ Sales Per Customer	% Δ Customers	% Δ Capital	% Δ GDP	% Δ Int. Rates	R^2
Step 1	.03 (29.4)			.13 (11.6)			.04
Step 2	.03 (20.8)		.28 (8.2)	.13 (11.4)			.06
Step 3	.03 (21.0)		.29 (8.5)	.13 (11.3)		-.04 (-3.8)	.06
Step 4	.04 (16.9)		.29 (8.6)	.13 (11.4)	-.19 (-3.8)	-.05 (-4.7)	.07
Step 5	.04 (16.7)	.05 (2.2)	.31 (8.8)	.13 (11.0)	-.24 (-4.4)	-.06 (-5.0)	.07

To understand the effect of each variable on the R^2 term, we added one variable at a time to the model using the Statistical Analysis System's "stepwise" procedure. This procedure begins with no variables in the model. For each of the independent variables, "stepwise" calculates an F statistic that reflects the variable's contribution to the explanatory power of the model if it is included. "stepwise" adds the variable with the largest F statistic to the model, and the process is repeated. After a variable is added, "stepwise" looks at all the variables already included in the model and deletes those that

do not produce an F statistic above a specified level. In our analysis, no variables were deleted after being added to the model. The results of the individual steps are contained in Table C-1.

C.3 Lagged Variables

Table C-2. Lagged Variable Regression Results

Independent Variable	Annual % Change in Non-Fuel Cost (R^2 = .17)	
	Estimate	T - Statistic
Intercept	0.03	11.9
%Δ Capital (t-1 to t)	0.11	7.8
%Δ Capital (t-2 to t-1)	0.09	5.9
%Δ Capital (t-3 to t-2)	0.12	8.5
%Δ Capital (t-4 to t-3)	0.08	5.7
%Δ Capital (t-5 to t-4)	0.00	1.1
%Δ Customers (t-1 to t)	0.22	6.0
%Δ Customers (t-2 to t-1)	-0.02	-0.6
%Δ Customers (t-3 to t-2)	0.07	2.1
%Δ Customers (t-4 to t-3)	-0.01	-0.21
%Δ Sales per Cust (t-1 to t)	0.02	0.9
%Δ GDP (t-1 to t)	-0.16	-2.6
%Δ Interest Rates (t-1 to t)	-0.06	-4.8

Results from the "stepwise" regressions indicate that percent change in capital and customers are the best predictors of changes in nonfuel cost. Next, we expanded the "Step 5" equation listed in Table C-1 to include several years of changes in capital and customers. We stopped adding years to our model when the estimate for a variable was no longer significant at the 5% level. This resulted in a model with five years of annual changes for capital and four years of annual changes for customers. This increased our R^2 term from .07 to .17. See Table C-2.

By adding together the individual estimates for capital and customers we calculate a five year cumulative estimate of 0.39 for Δ% capital and a four year cumulative estimate of 0.26 for Δ% customers.

C.4 Expected and Unexpected Changes

Table C-3. Expected and Unexpected Sales Change Regressions

Independent Variable	Annual % Change in Non-Fuel Cost (R^2 = .09)	
	Estimate	T - Statistic
Intercept	0.04	17.5
% Δ SPC - Expected	-0.12	-3.4
% Δ SPC - Unexpected	0.07	2.7
% Δ Customers	0.31	8.9
% Δ Capital	0.17	13.9
% Δ GDP	-0.19	-3.4
% Δ Interest Rates	-0.04	-3.3

We also tried to determine whether the changes were due to differences between expected and unexpected changes in sales per customer (SPC). We define expected change in SPC for each company as the average change in SPC for that company over the previous two years. Unexpected change in SPC is simply actual change in SPC less expected change in SPC. For example, if Company X's average SPC change during the last two years was 3% and actual SPC change in the current year is 4%, then expected percent change in SPC equals 3% and unexpected percent change in SPC equals 1%. See Table C-3. This regression indicates that expected sales growth decreases nonfuel costs while unexpected sales growth increases nonfuel costs. It seems implausible that "expected" sales growth would actually reduce nonfuel costs.

C.5 Summary

In Chapter 4 we showed that one-year changes in the number of customers have a fairly strong one-year impact on nonfuel costs but that one-year changes in sales have a rather weak effect. However, Chapter 4's results show that, even after accounting for the effects of these two variables and the autonomous trend or constant term, the vast majority of the year-to-year variation in nonfuel costs remains unexplained. In this appendix, we tried to identify factors, other than sales and customers, that contribute to changes in nonfuel costs.

First, we added additional variables to our regression model, including company-specific capital levels, national economic growth (GDP), and prevailing interest rates. The results of our analysis using the Statistical Analysis System's "stepwise" procedure indicate that changes in capital levels have the largest effect on changes in nonfuel costs, followed by changes in customers, interest rates, economic growth, and sales per customer, respectively. Using these five independent variables and a constant term the R^2 increased to .07, as compared to an R^2 of .02 reported in Chapter 4. However, even with these additional explanatory variables, the vast majority of the year-to-year variation in nonfuel costs remains unexplained.

Second, we expanded our regression model to include the effect of more than one year of changes in capital and customers. Using five years of changes in capital levels and four years of changes in customers, the R^2 term increased from .07 to .17.

Finally, we more closely scrutinized the relationship between sales per customer and nonfuel costs. Specifically, we separated the effects of expected and unexpected changes in sales per customer. This regression indicates that expected changes in sales per customer reduces nonfuel costs while unexpected changes increase nonfuel costs. We find it highly unlikely that nonfuel costs actually decrease when expected sales growth increases.

The regression work described in this appendix was based on industry data spanning from 1964 to 1988. The electric utility industry has undergone major structural changes during this time period. Before 1972 the industry experienced declining real costs and steady sales growth. In contrast, in the 1980's the industry embarked on large construction programs that increased real costs while sales growth became increasingly uncertain. Accordingly, the results of our statistical analysis should be carefully applied to the utility industry as it exists today.

Calculating the Cost of Risk

A successful decoupling mechanism can reduce a utility's risk of demand fluctuations, which is one of decoupling's primary purposes. But reductions in a utility's risk are not free; generally it is asserted that they come at the cost of increased risk to customers. Based on the experience of California utilities with ERAM, we expressed the concern that this assertion may be wrong (see Chapter 6).

California's experience with ERAM cannot, however, be used to make general statements about the risk-shifting implications of decoupling. In this appendix, we describe a method for making a quantitative estimate of the burden of any risk that is shifted and will make a rough calculation of its magnitude for an arbitrary but small increase in customer risk. Because our two best estimates of changes in consumer risk are PG&E at -2%, and SDG&E at -0.5%, it appears that any risk shift would be quite small, probably on the order of 1%. So our hypothetical example will be for an increase in consumer risk of 1%.

D.1 Is Rate Risk Correlated with Consumer Income?

A central question in the analysis of any risk is always the correlation of that risk with the bearer's portfolio. If the risk is correlated, then it adds much more to the bearer's risk than if it is uncorrelated. For instance if a customer's income uncertainty is $1000 and we add to that an uncorrelated risk of $100, then his total uncertainty is only $1005[28], while if we add a correlated risk of $100, his uncertainty will climb to $1100. This is simply the result of the laws of variance and covariance for random variables. These are:

$$Var(X+Y) = Var(X) + Var(Y) + 2\ Cor(X,Y)\ SD(X)\ SD(Y)$$
$$SD(X+Y) = SQRT(\ Var(X+Y)\ )$$

One would expect a customer's income to be correlated with the utility's revenue collection (without a decoupling revenue adjustment mechanism or RAM) because both are subject to macroeconomic influences. In other words, when the economy is good, revenues will be up, and a customer is likely to be doing better financially. Of course

[28] For uncorrelated variables, the variances are additive. Thus the total variance is 1,000,000 + 10,000. The standard deviation is the square root of the variance or approximately 1,005.

the correlation is far from perfect: some customers lose their jobs or have unanticipated expenses in good times, and some get raises in bad times. We will assume a rather high correlation of 0.5 in order to put an upper bound on the impact of risk from RAMs. Thus, we assume that rate increases dictated by the RAM balancing account often occur in conjunction with customer's negative income fluctuations.

Next we turn to the magnitude of the fluctuations. The typical household electric bill is about $1,000/year, and, as explained above, we will analyze an increase in the standard deviation of rates of 1%. This produces a uncertainty of about $10 in the customer's electric bill. We need three more inputs for our calculations: (1) income, (2) standard deviation of income, and (3) risk aversion. In order to present a conservative estimate of the value of risk, we will assume an low income ($30,000/year), a high standard deviation ($6,000/year), and a high risk aversion (2.0). This figure for risk aversion is for constant relative income risk aversion as defined and documented by Newbery and Stiglitz (1981). It essentially measures the curvature of an individual's utility function and is a dimensionless number.

As a preliminary calculation, we find that with a correlation of 0.5, the $10 uncertainty increases the income uncertainty of the customer from $6,000 to $6,015. We can now apply the risk-premium formula from Newbery and Stiglitz, which uses risk aversion, R, the coefficient of variation in income, σ, and the expected income Y.

We compute the pre-RAM consumer risk premium as:

$$\rho = \tfrac{1}{2} R \cdot \sigma^2 \cdot \bar{Y}$$

$$\rho = \tfrac{1}{2} \cdot 2 \cdot (6{,}000/30{,}000)^2 \cdot \$30{,}000 = \$1{,}200$$

For the post-RAM consumer, the risk premium is:

$$\rho = \tfrac{1}{2} \cdot 2 \cdot (6{,}005/30{,}000)^2 \cdot \$30{,}000 = \$1{,}202$$

So we see that the increase in risk premium resulting from the RAM is about $2, or 0.2% of electricity revenue. As we have indicated, this is probably an overestimate. If, for example, the correlation between individual customer income and the utility's revenue fluctuations is much less than half, which may well be the case, this could be a substantial overestimate.

To give the reader an idea of the sensitivity of our results to such changes in these assumptions, we have recomputed the risk premium for several sets of assumptions. The

results are presented in Table D-1. The interested reader can easily guess how slightly changes in any of these assumptions would affect the results simply by noting whether the variable affects the outcome linearly or quadratically.

Table D-1. Calculation of Risk-Shifting Premiums

Risk Aversion	Electric Bill Uncertainty ($/year)	Standard Deviation of Income ($/year)	Income ($/year)	Correlation	Electric Bill Risk Premium ($/year)
2.0	30	6,000	30,000	0.5	$2.00
1.0	30	6,000	30,000	0.5	$1.00
2.0	15	6,000	30,000	0.5	$1.00
2.0	30	3,000	30,000	0.5	$1.00
2.0	30	3,000	15,000	0.5	$2.00
2.0	30	6,000	30,000	0.25	$1.00

The cost of risk to the customer also needs to be considered in the context of the broader picture. The utility has had its revenue fluctuations reduced by 3%, and because profit is only about 12% of revenue, this should reduce fluctuations in profit by about 24%. This in turn should lead to a reduction in the cost of capital, which, if returned to ratepayers, would lead to lower rates. It is possible that passing these reductions on may save customers more than the cost of the extra risk.[29]

[29] On the other hand, the empirical record is currently very weak on the impact ERAM has had on the cost of capital for California utilities compared to other utilities.



Letter from the Co-Chairs of the National Action Plan for Energy Efficiency

To all,

As you know, the National Action Plan for Energy Efficiency is playing a vital role in advancing the dialogue and the pursuit of energy efficiency in our homes, buildings, and industries—an important energy resource for the country.

With the commitment and leadership from more than 60 diverse organizations nationwide we have made great progress in a short time. We have:

- Developed five broad and meaningful recommendations for pursuing cost-effective energy efficiency.
- Brought together more than 100 organizations from 50 states around this common goal to take energy efficiency to the next level.

However, there is much more to do. We remain substantially underinvested in efficiency at a time when using energy wisely can help address rising energy costs, rising emissions of greenhouse gases, and our dependence on foreign fuel supplies.

We need a concerted, sustained effort to overcome what are truly surmountable hurdles to making energy efficiency a larger part of our supply picture. To continue our progress we need to move from our initial Action Plan to implementation. We need a vision for where we want to be and a path for getting there.

Commensurate with that goal, we are pleased to offer this 2025 Vision for the National Action Plan. This Vision outlines what our long-term goals should be if we are to truly achieve all cost-effective energy efficiency. This Vision outlines what we consider are ten key implementation goals as well as the steps we need to take to achieve them. It is a framework for changing our course on energy efficiency.

This Vision represents the thinking of many leading organizations nationwide. Importantly, we believe that this Vision is a living document that looks out to long-term needs and will be modified to reflect new information and changing conditions.

We thank the Leadership Group for its contribution to this document. It is a pleasure to work with this committed group to advance energy efficiency to address the critical energy and environmental issues facing the country.

Sincerely,

Marsha H. Smith
President-Elect, National Association
Regulatory Utility Commissioners
Commissioner, Idaho Public Utilities Commission

James E. Rogers
President, Chairman, and CEO
Duke Energy



National Action Plan for Energy Efficiency

Vision for 2025:

Developing a Framework for Change

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2007

The Vision is a product of the National Action Plan for Energy Efficiency Leadership Group and does not reflect the views, policies, or otherwise of the federal government. The role of U.S. DOE and U.S. EPA is limited to facilitation of the Action Plan.

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<www.epa.gov/eeactionplan>

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List of Abbreviations and Acronyms

A

ACEEE	American Council for an Energy-Efficient Economy
AMI	advanced metering infrastructure

B

Btu	British thermal unit

C

CO_2	carbon dioxide

D

DOE	U.S. Department of Energy

E

EERE	U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EM&V	evaluation, measurement, and verification
EPA	U.S. Environmental Protection Agency

F

FERC	Federal Energy Regulatory Commission

G

GJ/t	gigajoules per tonne
GW	gigawatt
GWh	gigawatt-hour

H

HVAC	heating, ventilation, and air conditioning

I

ISO	independent system operator

K

kW	kilowatt
kWh	kilowatt-hour

L

LIHEAP	Low Income Home Energy Assistance Program

M

MEEA	Midwest Energy Efficiency Alliance
MMBtu	million British thermal units
MMcf	million cubic feet
MtC	metric tonnes of carbon
$MtCO_2e$	metric tonnes of carbon dioxide equivalent
MW	megawatt
MWh	megawatt-hour

N

NARUC	National Association of Regulatory Utility Commissioners
NEEA	Northwest Energy Efficiency Alliance
NEEP	Northeast Energy Efficiency Partnership
NYSERDA	New York State Energy Research and Development Authority

P

ppm	parts per million units

List of Abbreviations and Acronyms

R

R&D	research and development
RRP	regional resource planning

S

SEEA	Southeast Energy Efficiency Alliance
SWEEP	Southwest Energy Efficiency Partnership

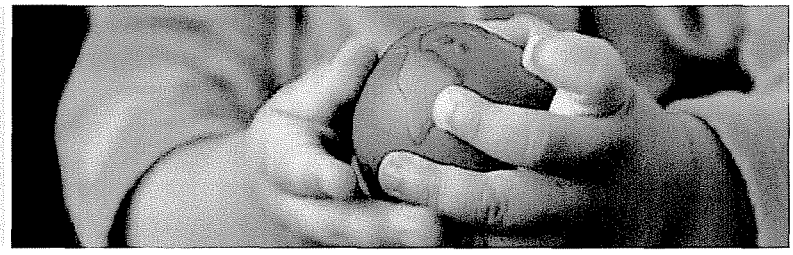
T

Tcf	trillion cubic feet
TWh	terawatt-hour

W

WAP	Weatherization Assistance Program
WGA	Western Governors' Association

Executive Summary



This Vision for the National Action Plan for Energy Efficiency establishes a goal of achieving all cost-effective energy efficiency by 2025; presents ten implementation goals for states, utilities, and other stakeholders to consider to achieve this goal; describes what 2025 might look like if the goal is achieved; and provides a means for measuring progress. It is a framework for implementing the five policy recommendations of the Action Plan, announced in July 2006, which can be modified and improved over time.

Background

Through the Leadership Group of the National Action Plan for Energy Efficiency (Action Plan), more than 60 diverse leading organizations recognized the importance of bringing greater emphasis to the role that cost-effective energy efficiency[1] can and should play in supplying our future energy needs. Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change in the near future. Energy efficiency can play a significant role in meeting our energy requirements, and it is a critical component of the overall modernization of utility energy systems worthy of the 21st century.

Despite the value that cost-effective energy efficiency offers, it is not achieving its full potential for a number of reasons. In July 2006, the Action Plan presented five key policy recommendations for fully developing the cost-effective energy efficiency resources in this country, building upon experiences in particular states and regions. It was a call to action to take investment in energy efficiency to the next level. As of November 2007, more than 100 organizations have endorsed these recommendations and/or made commitments to take energy efficiency to the next level within their spheres of influence.

As a next step, the Action Plan co-chairs challenged the Leadership Group to define a vision that would detail the steps necessary to fully implement the Action Plan. The Vision presented in this document is the response to that challenge. It includes establishment of a long-term aspirational goal and ten key implementation goals. It also describes what 2025 could look like if the long-term goal were achieved and provides a means for measuring progress over time. The Vision is provided as a framework to guide the changing policies toward energy efficiency for natural gas and electricity; it can be modified and improved over time.

Achieve All Cost-Effective Energy Efficiency

The long-term aspirational goal for the Action Plan is to achieve all cost-effective energy efficiency by the year 2025. Based on studies, the efficiency resource available may be able to meet 50 percent or more of the expected load growth over this time frame, similar to meeting 20 percent of electricity consumption and 10 percent of natural gas consumption.[2] The benefits from achieving this magnitude of energy efficiency nationally can be estimated to be more than $100 billion in lower energy bills in 2025 than would otherwise occur, over $500 billion in net savings, and substantial reductions in greenhouse gas emissions.

Importantly, the energy efficiency resource's role in meeting load and load growth may vary across the country due to regional differences in growth patterns, costs of energy, and other factors. Furthermore, the long-term goal is not a statement about the need for new power

supply additions in the future, as new plants may be a critical component of the desired modernization of the energy supply and delivery system. However, the greater the energy efficiency savings, the greater the likelihood that efficiency gains can help replace older, less efficient power supply options, resulting in substantial environmental benefits.

Ten Implementation Goals

The Vision suggests that implementation of a number of policies will enhance the likelihood that the long-term goal will be achieved. Energy efficiency needs to be valued similarly to supply options. Utilities and investors need to be financially interested in saving energy. State activity is key in this transformation of natural gas and electricity supply and delivery, including updating and enforcing codes and standards to ensure that savings are captured as new buildings and products enter the system. Customers must also have the proper incentives to make investments in cost-effective energy efficiency. With such policies in place, cost-effective energy efficiency can be a key component of the modernization of the energy supply and delivery system and help to transform how customers receive and value energy services.

These policies are included in the following ten implementation goals. These goals provide a framework for implementing the recommendations of the Action Plan by outlining the key steps state decision-makers should consider to help achieve the 2025 Vision. The time line for achieving these implementation goals is by 2015 to 2020, so that the necessary policy foundation is in place to help ensure success of the 2025 Vision.

Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource

Utilities[3] and applicable state agencies are encouraged to:

- Create a process to explore the energy efficiency potential in the state and commit to its full development.
- Regularly identify cost-effective energy efficiency potential in conjunction with state rate making bodies.
- Set energy savings goals consistent with the cost-effective potential.
- Integrate energy efficiency into energy resource plans at the utility, state, and regional levels.

Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources

Applicable state agencies are encouraged to:

- Work with utilities to implement revenue mechanisms to promote utility and shareholder indifference to supplying energy savings, as compared to energy generation options.
- Consider how to remove utility disincentives to energy efficiency such as by removing the utility throughput disincentive and exploring other rate making ideas.
- Ensure timely cost recovery in place for parties that administer energy efficiency programs.

Goal Three: Establishing Cost-Effectiveness Tests

Applicable state agencies along with key stakeholders are encouraged to:

- Establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.
- Incorporate cost-effectiveness tests into rate making procedures going forward.

Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms

State rate making bodies are encouraged to:

- Work with stakeholders to adopt effective, transparent practices for the evaluation, measurement, and verification (EM&V) of energy efficiency savings consistent with establishment of rate making incentives.

Program administrators are encouraged to:

- Conduct EM&V consistent with these practices.

Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms

Applicable agencies are encouraged to:

- Clearly establish who will administer energy efficiency programs.
- Review programs, funding, customer coverage, and goals for efficiency programs; ensure proper administration and cost recovery of programs, as well as ensuring that goals are met.
- Establish goals and funding on a multi-year basis to be measured by evaluation programs established.
- Create public education programs for energy efficiency.
- Ensure that best practice information is shared regionally and nationally.

Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices

Applicable agencies are encouraged to:

- Have a mechanism to review and update building codes.
- Establish enforcement and monitoring mechanisms of energy codes.
- Adopt and implement state-level appliance standards.
- Develop and implement lead-by-example energy efficiency programs at the state and local levels.

Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency

Utilities and state rate making bodies are encouraged to:

- Examine, propose, and modify rates considering impact on customer incentives to pursue energy efficiency.
- Create mechanisms to reduce customer disincentives for energy efficiency (e.g., financing mechanisms).

Goal Eight: Establishing State of the Art Billing Systems

Utilities are encouraged to:

- Work with large customers to develop methods of supplying consistent energy use and cost information across states, service territories, and the nation.

Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems

Utilities and other program administrators are encouraged to:

- In conjunction with their regulatory bodies, explore the development and implementation of state of the art efficiency delivery information, including smart grid infrastructures, data analysis, two-way communication programs, etc.
- Explore methods of integrating advanced technologies to help curb demand peaks and monitor efficiency upgrades to prevent equipment degradation, etc.
- Coordinate demand response and energy efficiency programs to maximize value to customers.
- Support development of an energy efficiency services and program delivery channel (e.g., quality trained technicians).

Goal Ten: Implementing Advanced Technologies

Applicable state agencies and utilities are encouraged to:

- Review advanced technologies such as batteries, strategically integrated solar facilities, and other clean distributed generation forms; ensure their adaptation into the broader resource plans for efficiency achievements.
- Work collectively to review advanced technologies and determine rapid integration time lines.

The Energy System in 2025

An energy system in 2025 that would evolve with the suite of energy efficiency policies in place as outlined above and that captures all cost-effective energy efficiency will be different from the one we have today. Some of the key differences based on the effects that some of these policy changes are having in parts of the country, as well as expectations of some of the advantages that new technology and system modernization can bring, are highlighted below from the perspectives of the energy customer and society.

- **Customers** across the residential, commercial, and industrial sectors would have ready, uniform access to comprehensive energy efficiency services across the country. These services would bring a range of efficiency improvements to homes, buildings, and facilities and reduce customers' bills below what they would have been without these programs. Customers would also have clear information on the cost of energy and increased awareness of their total energy use. In addition, new efficient appliances and other equipment will help to control the peak demand of utility systems and give large customers greater flexibility in how they manage and control their own operations to reduce energy use, reduce costs, and increase their own competitive positions. New homes and buildings would meet up-to-date energy codes.
- **Society** would benefit from significantly modernized energy supply, transmission, and distribution systems and, with increased investment in cost-effective energy efficiency, would benefit from lower overall cost of energy supply, increased fuel diversity, and lower emissions of air pollutants and greenhouse gases. The low-income populations would benefit, in particular, from the lower energy bills resulting from a commitment to deliver energy efficiency to these customer classes. Society may also see economic benefits from the greater employment necessary to build an industry capable of delivering energy efficiency services at this broad scale, from a robust business in energy efficiency products and services, and from using more capital locally.

Measuring Progress

Measurement of the progress toward full implementation by 2015 to 2020 is an important part of the Vision. Progress will be measured and reported on every few years. As of 2007, based on information collected from across the country, there is a strong basis of experience with these energy efficiency policies upon which to draw and to expand. For example, more than a dozen states that are looking to advance energy efficiency have:

- Established a policy to recognize energy efficiency as a high-priority resource.
- Identified the cost-effective, long-term potential for energy efficiency and established energy savings goals consistent with this potential.
- Established cost-effectiveness tests for energy efficiency consistent with the long-term benefits of energy efficiency.
- Established tailored energy efficiency programs for their various types of customers.
- Integrated the energy efficiency savings goals into state energy resource plans.

There is also more progress to make. For example, a few additional states have also looked to the following policy steps to advance energy efficiency:

- Aligned utility incentives with the delivery of cost-effective energy efficiency.
- Provided for stable (multi-year) funding for energy efficiency programs.

Beyond the adoption of the key policies and programs at the state level, progress will be measured in terms of:

- Energy expected to be saved through energy savings goals (kWh, kW, and therms).

- Energy that has been saved (kWh, kW, and therms).
- Reductions in emissions of carbon dioxide.
- Dollars invested in energy efficiency programs.
- Cost-effectiveness of energy efficiency program delivery.

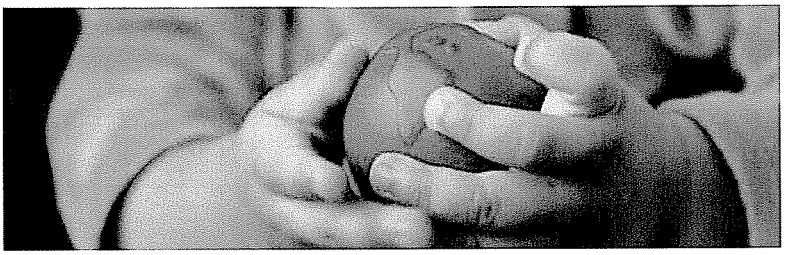
Next Steps

This Vision is offered as a framework to assist change in energy efficiency and related policies and programs at the state level across the country, toward the goal of achieving all cost-effective energy efficiency in 2025. It presents a snapshot of where the country is in 2007 based on the collection and organization of available state-level information on the existing policy and program options. This snapshot, as well as other elements of the Vision, will be updated as new information becomes available and improved as information changes. People are encouraged to provide additional information and their comments for how to refine this Vision to the Action Plan Leadership Group. Please send feedback to the Action Plan sponsors via Larry Mansueti, U.S. Department of Energy (lawrence.mansueti@hq.doe.gov, 202-586-2588) and Stacy Angel, U.S. Environmental Protection Agency (angel.stacy@epa.gov, 202-343-9606).

Notes

1. "Energy efficiency" refers to using less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way. As used here, the term includes using less energy at any time, including at times of peak demand through demand response and peak shaving efforts.
2. The energy efficiency savings as a percent of load growth and savings depend on forecast assumptions used and vary by region. This magnitude of savings is consistent with the potential savings documented in a number of recent studies. See Appendix B for references for these studies.
3. "Utility" refers to any organization that delivers electric and gas utility services to end-users, including investor-owned, cooperatively owned, and publicly owned utilities.

1: Introduction



Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, environmental concerns, and global climate change in the near term (Figure 1-1). Mining this efficiency could help us meet on the order of 50 percent or more of the expected growth in U.S. consumption of electricity and natural gas in the coming decades, yielding many billions of dollars in saved energy bills and avoiding significant emissions of greenhouse gases and other air pollutants.[1]

Scope of the Vision for 2025

Recognizing this large opportunity, more than 60 leading organizations representing diverse stakeholders from across the country joined together to develop the National Action Plan for Energy Efficiency. The Action Plan identifies many of the key barriers contributing to underinvestment in energy efficiency, outlines five key policy recommendations for achieving all cost-effective energy efficiency, focusing largely on state-level energy efficiency policies, and provides a number of options to consider in pursing these recommendations (Figure 1-2). As of November 2007, more than 100 organizations have endorsed the Action Plan recommendations and/or made public commitments to implement them in their areas (Figure 1-3).

As a next step, the Action Plan co-chairs challenged the Leadership Group to define a vision for the Action Plan which would detail the steps necessary to fully implement the recommendations of the Action Plan. The Vision presented in this document is the response to that challenge.

This Vision includes establishment of a long-term aspirational goal and the establishment of ten key implementation goals. It also describes what 2025 could look like if the goal were achieved and provides a means for measuring progress over time. Further, the Vision reviews the potential interactions between the largely state-level energy efficiency policies of the Action Plan and other existing state, regional, or federal policies such as clean energy portfolio standards[2] and greenhouse gas mitigation policies and provides recommendations to ensure that these polices are designed to leverage energy efficiency as a cost-effective resource.

The 2025 Vision is offered as a general framework for pursuing a variety of policy options at the state level for advancing cost-effective energy efficiency as would be consistent with regional, state, and local circumstances, maintaining a fundamental principle of the Action Plan that one size does not fit all. This general framework leaves the policy details and the decision of whether to implement a policy to be determined through appropriate processes. It is a framework that can be updated and improved over time.

This document does not address the best practices for developing and implementing cost-effective energy efficiency program and portfolios, as these issues have been addressed elsewhere through the Action Plan.[3] However, it does offer the implementation goals and steps to assist in the establishment of the necessary policy framework to support the growth of best practice energy efficiency programs across the country. These types of programs are of interest for the following reasons:

- **Large energy savings available in existing homes, buildings, and industrial facilities.** The homes, commercial buildings, and industrial facilities already in place offer many opportunities for saving energy cost-effectively. Options exist through improved building envelopes and tighter ducts in addition to more efficient lighting, appliances, heating and cooling, and a variety of industrial process

Figure 1-1. Reasons for the National Action Plan for Energy Efficiency

- **Energy efficiency is a large, untapped, low-cost energy resource.** Energy efficiency on the order needed to meet 50 percent or more of expected growth for natural gas and electricity is available at a cost of less than half of new generation, in many parts of the country. Overall savings from pursing this efficiency would be more than $100 billion annually by 2025.*

- **Energy efficiency improves energy security.** Energy efficiency reduces the level of U.S. per capita energy consumption, thus decreasing the vulnerability of the economy and individual consumers to disruptions from natural disasters or terrorist acts. Energy efficiency also improves system reliability and reduces the potential for disruptions from brownouts or blackouts.

- **Energy efficiency mitigates risk of future carbon policy.** Pending regulation of greenhouse gas emissions presents significant uncertainty as to the generation investments that will contribute to a low-cost energy system for the future. Importantly, energy efficiency is low-cost now, will stay low-cost, and presents an important resource option for the future, particularly while waiting for the uncertainty to be resolved. Efficiency also makes sizable reductions in carbon emissions more attainable. Without moderating demand growth, investment in energy efficiency and other clean energy sources will be necessary.

- **Higher prices do not remove the barriers that impede investment in cost-effective energy efficiency.** Price signals alone (based on time of use rates) are insufficient to realize the full energy efficiency potential, in part due to large and persistent market barriers, including the principal-agent problem** transaction costs, and lack of information as well as customer requirements for very short paybacks.*** Specific policies are necessary to target and overcome these well-defined barriers for energy efficiency. Many policies play a role in overcoming the barriers, such as up-to-date appliance standards, building codes, and organized energy efficiency programs.

- **Carbon policies will not necessarily remove the barriers to energy efficiency.** A variety of approaches for limiting emissions of greenhouse gases are at various stages of discussion and development across the country at the state, regional, and national levels. Most approaches (e.g., cap and trade and carbon taxes) provide a carbon price signal but do not directly address the unique barriers to energy efficiency. Therefore, provisions to address these barriers to efficiency within carbon policies as well as complementary policies to promote the delivery of cost-effective energy efficiency will be essential to mine the low-cost greenhouse gas reductions from energy efficiency.

- **Utilities are well-positioned to deliver energy efficiency programs, but regulatory changes may be necessary so that they are as profitable when saving energy as in generating or delivering energy.** Utilities typically have strong relationships with their customers, will accept longer paybacks for investments than customers will, and have access to lower-cost capital. However, the regulatory structure has historically rewarded utilities for building supply infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when energy-saving measures cost less than constructing new infrastructure. Some states have modified utility regulatory policies to eliminate efficiency disincentives. Alternative mechanisms such as third-party administration of energy efficiency programs have also been used.

- **Parties embrace energy efficiency for different reasons and solutions can be designed to address all these motivations.** For all of these reasons, advancing energy efficiency programs and policies requires attention and commitment by a critical mass of leading parties, including regulators, utilities, state governments, consumer advocates, environmental groups, and large end-users.

* See Chapter 2 for more information on these benefits.

** The principal-agent problem exists when the entity who makes energy efficiency investments, such as a landlord, is different from the entity who pays the energy bills, such as a tenant.

*** See Appendix B for references to studies that discuss the existing barriers to energy efficiency in more detail

Note: This set of reasons is based on experience of the Action Plan Leadership Group and input received through Regional Implementation Meetings and the Sector Collaborative for Energy Efficiency

Figure 1-2. National Action Plan for Energy Efficiency Recommendations & Options

Recognize energy efficiency as a high-priority energy resource.

Options to consider:

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.

Options to consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy-efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust measurement and verification procedures.
- Designating which organization(s) is responsible for administering the energy-efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Broadly communicate the benefits of and opportunities for energy efficiency.

Options to consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level, addressing relevant customer, utility, and societal perspectives.
- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.
- Communicating the role of building codes, appliance standards, and tax and other incentives.

Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

Options to consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options, such as revenue requirement or resource procurement funding, system benefits charges, rate-basing, shared-savings, and incentive mechanisms.
- Establishing funding for multi-year periods.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Options to consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.
- Providing utility incentives for the successful management of energy efficiency programs.
- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.
- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.
- Adopting rate designs that encourage energy efficiency by considering the unique characteristics of each customer class and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit-sharing programs and on-bill financing.

Figure 1-3. Commitments to Implement the Recommendations of the Action Plan (as of November 2007)*

Type of Commitment	Number of Organizations
Establishing and supporting state-level collaborative processes to explore how best to increase investment in energy efficiency	15
Additional money to be spent on energy efficiency programs	4
Start new and/or expand existing energy efficiency programs	17
Exploring policies and practices to align utility incentives with the delivery of cost-effective energy efficiency	5
Advancing efforts to include energy efficiency on a consistent and comparable basis with supply-side resources in future resource planning activities	24
Meeting aggressive energy savings goals	26
Proactively educating stakeholders on the benefits of and opportunities for energy efficiency	63

* See the Action Plan Web site (www epa gov/eeactionplan) for a full listing of energy efficiency commitments.

improvements. The buildings in existence today will remain the vast majority of the nation's buildings and facilities for years to come, and there are a variety of proven, cost-effective energy efficiency programs that can be employed to pursue these opportunities.

- **Importance of new construction.** Efforts to encourage higher energy efficiency in building codes and building beyond code complement energy efficiency programs focused on existing buildings and facilities. In any given year, more energy savings can be harvested from existing buildings in total than from new construction, but new buildings determine the long-term energy footprint of the built infrastructure. Thus it is critical to identify and realize the cost-effective efficiency potential in new buildings. There are a number of approaches for improving the requirements, training, and verification of new construction efforts.

- **Opportunities across customer classes.** Energy efficiency measures are available and can be pursued in all customer classes. Conventional regulatory cost allocation practices can be applied to energy efficiency to ensure that all classes pay their fair share of program costs. The barriers to energy efficiency in each of the customer classes are distinct; policies and programs can account for these differences. Energy efficiency programs may be especially important and yet challenging for low-income energy consumers, because these customers can face difficult economic choices that lead to inefficient energy use. Because of the larger economic barriers in place and because of the distinct social value associated with energy efficiency for low-income households, programs targeting these households may not be expected by some regulatory authorities to meet the same cost-effectiveness thresholds as other programs.

- **Evolving technology will offer new opportunities.** Technology performance and costs are evolving rapidly, offering new opportunities to meet load growth. These new technologies need to be effectively integrated into energy efficiency program design as well as the enabling policies for energy efficiency programs to capture these new opportunities. This document incorporates several policies for making progress with the integration of these technologies. It is expected that this is one of the areas that will be updated in the future.

This Document

The 2025 Vision is presented in the following sections:

- **Chapter 2: The Goals of the 2025 Vision.** This chapter outlines the long-term goal of this Vision and ten implementation goals for pursing the steps necessary to meet the long-term goal. It also outlines a way to measure progress toward the 2025 goal in terms of the percent of the states that have adopted key policies, in part or in full, and in terms of other key indicators of progress such as energy saved, dollars spent, and greenhouse gas emissions avoided.
- **Chapter 3: The Vision for 2025.** This chapter describes what the energy system could look like in 2025 if the Vision is achieved and the Action Plan recommendations are fully implemented from a variety of perspectives. It also outlines a number of evolving policies and technologies and the role they may play in achieving the Vision. As the Vision is updated in the future, attention will be paid to how best to address these changes.
- **Chapter 4: Related State, Regional, and National Policies.** This chapter identifies important interrelationships between other federal, regional, and state energy and environmental policies, and provides a number of recommendations and considerations for integrating these efforts so that they act in tandem to promote investment in cost-effective energy efficiency and do not impede each other.
- **Chapter 5: Tools and Assistance to Help Realize the Vision.** This chapter reviews the progress that is expected through the first goal period of this national Vision and shows the tools and resources that are available to help states make progress toward these goals.

Development of the Action Plan Vision for 2025

The National Action Plan for Energy Efficiency was developed by a diverse group of leading organizations from across the country, including public and private utilities, regulators, other state decision-makers, policy advocates, and large end-users. It also engaged many trade associations (see Appendix A). The Action Plan process is chaired by James Rogers, CEO and President of Duke Energy and Marsha Smith, President-Elect of NARUC.[4] It is facilitated by the U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE).

This document was developed under the guidance of a work group of Leadership Group participants. The work group was composed of 17 organizations, representing stakeholder perspectives including investor-owned utilities, regulatory commissions, other state decision-makers, cooperatives, municipal utilities, and energy and environmental policy advocates. Four conference calls were held for the work group to discuss the initial outline and approach, goals and tracking, complementary policies, and the draft report. The Vision work group members are:

Glenn Cannon	Waverly Light and Power
Jorge Carrasco	Seattle City Light
Sheryl Carter	Natural Resources Defense Council
Ollie Frazier	Duke Energy
Anne George	Connecticut Department of Public Utility Control
Dian Grueneich	California Public Utilities Commission
Jeff Genzer	National Association of State Energy Officials
Sandra Hochstetter	Arkansas Electric Cooperative Corporation (formerly with the Arkansas Public Service Commission)
Chris James	formerly with the Connecticut Department of Environmental Protection

Mary Kenkel	Alliance One (consultant to Duke Energy)
Michelle New	National Association of State Energy Officials
Bill Prindle	American Council for an Energy-Efficient Economy
Roland Risser	Pacific Gas and Electric
Richard Robinson	National Rural Electric Cooperative Association
Gene Rodrigues	Southern California Edison
James Rogers	Duke Energy
Marsha Smith	Idaho Public Utilities Commission
Jim Spiers	Tri-State Generation and Transmission Association, Inc.
Mike Winka	New Jersey Board of Public Utilities
Janet Streff	MN Department of Commerce

Further, information for this document was compiled, in part, through a set of regional implementation meetings for the Action Plan. As part of these meetings, information on the status of the adoption of a variety of policies and other action steps was provided for review and additional comment. This information was subsequently sent to state organizations for further comment. These state and regional summaries form the baseline for the initial measuring progress approach presented as a "strawman" and summarized in Chapter 3.

In addition, two conference calls were offered to the entire Leadership Group in order to solicit further comments and provide additional information.

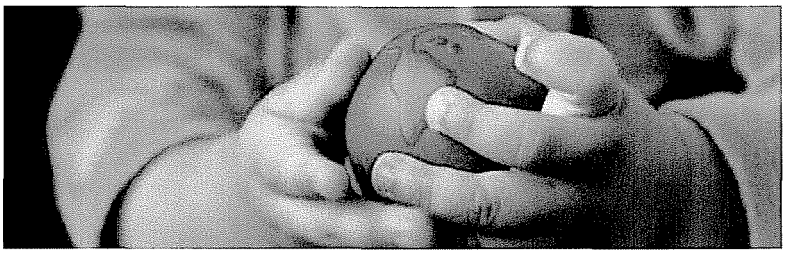
The Intent of the 2025 Vision

This Vision document is offered as a framework to guide changes in energy efficiency policies and programs toward the goals of achieving all cost-effective energy efficiency. The decision of whether to adopt a policy or program and particular design details at the state level are, of course, to be determined through state processes that address state goals, objectives, and circumstances.

Notes

1. Meeting 50 percent of energy consumption is similar to meeting 20 percent of electricity consumption and 10 percent of natural gas consumption, subject to forecast assumptions used. These savings are consistent with the potential savings documented in a number of recent studies. See Appendix B for references for these studies. Across the country, the potential for cost-effective energy efficiency varies, subject to a number of area-specific factors, such as load growth, energy efficiency approaches pursued, local economics, and existing infrastructure.
2. Clean energy portfolio standards direct utilities and other retail electric providers to supply a specified amount of energy from clean resources, such as energy efficiency and renewable energy.
3. See "Energy Efficiency Program Best Practices," Chapter 6 in the *National Action Plan for Energy Efficiency* Report.
4. Diane Munns of the Iowa Utilities Board, while President of NARUC, served as the initial co-chair of the Action Plan.

2: The Goals of the 2025 Vision



The 2025 Vision for the National Action Plan for Energy Efficiency includes establishment of a long-term aspirational goal and ten key implementation goals. These goals and a set of steps to take to achieve them are offered as a framework for the implementation of the Action Plan recommendations and to guide state-level policies toward energy efficiency where it is cost-effective. In addition, the framework helps in measuring progress toward the 2025 Vision. This Vision will be updated and improved over time as new information becomes available.

The Long-Term Goal: Achieve All Cost-Effective Energy Efficiency

Building upon the five recommendations of the National Action Plan, the long-term aspirational goal of this effort is to achieve all cost-effective energy efficiency by the year 2025. Achieving this goal will yield important environmental and economic benefits while integrating energy efficiency into the modernization of the nation's energy system.

Based on available studies, the cost-effective energy efficiency resource available may be able to meet 50 percent or more of the expected load growth nationally. This is similar to meeting 20 percent of electricity consumption and 10 percent of natural gas consumption given current forecasts for future energy demand.[1] Benefits from achieving this magnitude of energy efficiency can be estimated to be:

- More than $100 billion in lower energy bills in 2025 than would otherwise occur.
- Annual energy savings exceeding 900 billion KWh.
- Equivalent to over 50 GW of power, or more than 100 500 MW power plants over 20 years.
- Over $500 billion of total net savings.[2]
- Reductions in greenhouse gas emissions on the order of 500 million metric tons of CO_2 annually, equivalent to 90 million cars off the road.

These benefits reflect the full implementation of best practice energy efficiency programs currently being delivered in some parts of this country, as well as the broad adoption of up-to-date building codes and other energy efficiency policies.

Importantly, the role that the energy efficiency resource may play in meeting load or load growth (or in replacing existing generation options) varies across the country due to regional differences in growth patterns, costs of energy, existing infrastructure, and other factors. In high growth areas, as an example, perhaps less of the expected growth could be addressed and in slower growing areas, perhaps substantially more. In addition, cost-effectiveness needs to be determined at a state and local level. Furthermore, the long-term goal is not meant to imply that new power plant additions are not needed in the future, as new plants may be a critical component of the desired modernization of the energy supply and delivery system. Indeed, the greater the energy efficiency savings, the greater the likelihood that efficiency gains can help replace older, less efficient power supply options, resulting in substantial environmental benefits.

Ten Implementation Goals

For the long-term goal to be achieved, a number of policies need to be in place. Energy efficiency needs to be valued similarly to supply options. Utilities and investors need to be financially interested in saving energy. States must be active in this transformation of energy supply and delivery, including updating and enforcing codes and standards to ensure that savings are captured as new buildings and products enter the system. Customers must also have the proper incentives to make investments in cost-effective energy efficiency. With such policies in place, cost-effective energy efficiency can be a key component of the modernization of the energy supply and delivery system and help to transform how customers receive and value energy services.

These policies are included in the following ten implementation goals. These goals provide a framework for implementing the recommendations of the Action Plan by outlining the key steps state decision-makers should consider to help achieve the 2025 Vision. The timeline for achieving these implementation goals is by 2015 to 2020, so that the necessary policy foundation is in place to help ensure success of the 2025 Vision. With most of these policy and program steps, there is significant experience across the country and substantial materials and lessons learned that can be drawn upon. However, there are some policies and technologies that are emerging and may evolve in a variety of ways; such policies are explored further in Chapter 3 and future updates to the Vision will highlight progress in these areas.

The ten implementation goals and key steps to achieve them are outlined below. A description of how progress in implementing these goals can be measured follows.

Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource

Utilities[3] and applicable state agencies are encouraged to:

- Create a process to explore the energy efficiency potential in the state and commit to its full development.
- Regularly identify cost-effective energy efficiency potential in conjunction with state ratemaking bodies.
- Set energy savings goals consistent with the cost-effective potential.
- Integrate energy efficiency into energy resource plans at the utility, state, and regional levels.

Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources

Applicable state agencies are encouraged to:

- Work with utilities to implement revenue mechanisms to promote utility and shareholder indifference to supplying energy savings, as compared to energy generation options.
- Consider how to remove utility disincentives to energy efficiency such as by removing the utility throughput disincentive and exploring other ratemaking ideas.
- Ensure timely cost recovery in place for parties that administer energy efficiency programs.

Goal Three: Establishing Cost-Effectiveness Tests

Applicable state agencies along with key stakeholders are encouraged to:

- Establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.
- Incorporate cost-effectiveness tests into ratemaking procedures going forward.

Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms

State ratemaking bodies are encouraged to:

- Work with stakeholders to adopt effective, transparent practices for the evaluation, measurement, and verification (EM&V) of energy efficiency savings consistent with establishment of ratemaking incentives.

Program administrators are encouraged to:

- Conduct EM&V consistent with these practices.

Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms

Applicable agencies are encouraged to:

- Clearly establish who will administer energy efficiency programs.
- Review programs, funding, customer coverage, and goals for efficiency programs; ensure proper administration and cost recovery of programs, as well as ensuring that goals are met.
- Establish goals and funding on a multi-year basis to be measured by evaluation programs established.
- Create public education programs for energy efficiency.
- Ensure that best practice information is shared regionally and nationally.

Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices

Applicable agencies are encouraged to:

- Have a mechanism to review and update building codes.
- Establish enforcement and monitoring mechanisms of energy codes.
- Adopt and implement state-level appliance standards.
- Develop and implement lead-by-example energy efficiency programs at the state and local levels.

Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency

Utilities and state ratemaking bodies are encouraged to:

- Examine, propose, and modify rates considering impact on customer incentives to pursue energy efficiency.
- Create mechanisms to reduce customer disincentives for energy efficiency (e.g., financing mechanisms).

Goal Eight: Establishing State of the Art Billing Systems

Utilities are encouraged to:

- Work with large customers to develop methods of supplying consistent energy use and cost information across states, service territories, and the nation.[4]

Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems

Utilities and other program administrators are encouraged to:

- In conjunction with their regulatory bodies, explore the development and implementation of state of the art energy delivery information including smart grid infrastructures, data analysis, two-way communication programs, etc.
- Explore methods of integrating advanced technologies to help curb demand peaks and monitor efficiency upgrades to prevent equipment degradation, etc.
- Coordinate demand response and energy efficiency programs to maximize value to customers.
- Support development of an energy efficiency services and program delivery channel (e.g., quality trained technicians).

Goal Ten: Implementing Advanced Technologies

Applicable state agencies and utilities are encouraged to:

- Review advanced technologies such as batteries, strategically integrated solar facilities, and other clean distributed generation forms; ensure their adaptation into the broader resource plans for efficiency achievements.
- Work collectively to review advanced technologies and determine rapid integration timelines.

The Vision for Cooperatively and Publicly Owned Utilities

The Vision goals are broad, intended for all types of utilities to take the applicable steps necessary to capture the benefits of greater energy efficiency. While much of the resource planning and energy efficiency program issues relate to all utility types, cooperatively and publicly owned utilities operate under different ratemaking and utility financing considerations than investor-owned utilities. Some of the key steps under Goal Two, relating to utility financial incentives, may not apply to cooperatively and publicly owned utilities. These utilities typically operate on an annual budget basis rather than a cost-recovery basis, are regulated by their board members, and are typically not subject to state utility regulation.

The key financial indicator for a cooperatively or publicly owned utility is its debt coverage ratio (which is critical to maintaining a high bond rating and low cost capital) or its minimum cash position (for utilities with no debt). Typically, these utilities can adjust rates whenever the debt coverage ratio or minimum cash position falls below a threshold. An investor-owned utility may need to wait until a formal rate case proceeding to adjust rates for decreases in sales from energy efficiency; the effect of energy efficiency on cooperatively and publicly owned utilities' financial health, however, is relatively modest. The publicly and cooperatively owned utilities will experience similar financial health problems as investor-owned utilities if they do not adjust rates.

Measuring Progress

Measurement of the progress in achieving the ten implementation goals by 2015 to 2020 is an important part of the Vision. Progress will be measured and reported on every few years, with an emphasis on measurable outcomes. An initial summary of the implementation of key policy and program steps in support of the Vision across the 50 states and the District of Columbia is provided in Figures 2-1 and 2-2 for electricity and natural gas systems, respectively. These figures show the number of states that have implemented key policy and program steps, in whole or in part, as of 2006/2007. The approach used to assess this progress is offered as an initial strawman approach and will be refined in the future as part of efforts under the Action Plan. The information presented was collected through a series of interactions with state-level organizations. More detail on this strawman approach is provided below and in Appendix D. The summary of progress shows there is a strong base of experience, with many of these energy efficiency policies and programs upon which to draw and expand.

Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource

Progress can be measured as utilities and applicable state agencies work to accomplish the following:

1. **Process in place, such as a state and/or regional collaborative, to pursue energy efficiency as a high-priority resource.** A valuable early step is to establish a collaborative process involving all appropriate stakeholders. State and or regional collaboratives, representing a diverse group of stakeholders such as utilities, state policy makers, consumers, businesses, and energy service companies, help raise awareness of the value of greater investment in energy efficiency, review the available options, reach agreement among stakeholders on feasible energy savings goals and appropriate funding, and resolve important program and administrative issues. The resulting broader understanding of energy efficiency leads to generally smoother processes in energy efficiency programming, both as new programs are being started and as programs are expanded and improved over time. A collaborative for energy efficiency can be a stand-alone process or one that is part of a state energy planning, state clean energy planning, or climate change planning process. It can have a variety of charters and anticipated longevity.

Examples include California, Kentucky, and Minnesota at the state level and the Western Governors' Association's Clean and Diversified Energy Advisory Committee at the regional level (National Action Plan for Energy Efficiency, 2006).[5,6]

2. **Policy established to recognize energy efficiency as a high-priority resource.** Another important early step is recognizing energy efficiency as a high-priority resource in energy planning. Energy efficiency needs to be considered on the same basis as conventional supply options when it is less expensive than the conventional options. This may be an important change in perspective for entities that are used to focusing on conventional supply options. It is important to review and address any limitations in state statutes to ensure that energy efficiency can be appropriately considered. Further, explicitly establishing energy efficiency as the first or among the first resources requires the relevant entities to bring energy efficiency to the top of their planning process. A number of states have recognized energy efficiency as a high-priority resource due to its broad benefits through a variety of policy directives. For example, the California Energy Action Plan II has established energy efficiency as the first resource to be developed in the state (CEC and CPUC, 2005). In addition, legislation passed in Illinois in 2007, and gubernatorial action in New York, Connecticut and Massachusetts, initiate actions that will recognize energy efficiency as a high-priority resource.

3. **Potential identified for cost-effective, attainable energy efficiency over the long term.** A key step in developing energy efficiency programs is analyzing the potential for all cost-effective energy efficiency in the specific jurisdiction over the long term across all customer classes. Because energy usage patterns, technologies, and costs change over time, it is important to have an up-to-date study that incorporates the latest information on energy costs, energy forecasts, and available energy efficiency options. Such a study helps parties have realistic expectations of what can be achieved, informs energy efficiency savings goals and funding targets, and guides program design.

4. **Energy efficiency savings goals established consistent with cost-effective potential.** Energy efficiency savings goals are being used in several states to help set a high-level policy direction and to establish energy savings targets that can be integrated into resource planning efforts. These savings targets should reflect an understanding of the true cost-effective potential for increased effectiveness.

5. **Energy efficiency savings goals incorporated into state resource plan, with provisions for regular updates.** The integration of energy efficiency resources and an energy savings target into formalized resource planning processes at the state and utility levels can help establish the rationale for energy efficiency funding levels and for properly valuing the benefits. Resource plans account for the long-term benefits from energy savings, capacity savings, potential reductions of air pollutants and greenhouse gases, and improved reliability, as well as other benefits. Provisions for routine review and updating of these resource plans are important.

6. **Energy efficiency savings goals integrated into a regional energy resource plan.** The integration of energy efficiency resources and an energy savings target into a resource planning process at the regional level may also have value by developing a view of the resources necessary and the role that energy efficiency can play across a broader area. There may be opportunities to explore the role that energy efficiency can play in regional efforts as entities respond to the federal policies recently promulgated by the Federal Energy Regulatory Commission (FERC) and DOE which promote the use of regional electric system planning efforts.

Figure 2-1. Progress in Meeting Implementation Goals: Strawman Approach for Electricity Services*

	Implementation Goal and Key Steps: Electricity Services	States Having Adopted Policy or Step as of 2007	
		Completely	Partially
Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource			
1	Process in place, such as a state and/or regional collaborative, to pursue energy efficiency as a high-priority resource	21	0
2	Policy established to recognize energy efficiency as a high-priority resource	16	9
3	Potential identified for cost-effective, attainable energy efficiency over the long term	17	5
4	Energy efficiency savings goals established consistent with cost-effective potential	10	5
5	Energy efficiency savings goals integrated into state energy resource plan, with provisions for regular updates	14	9
6	Energy efficiency savings goals integrated into a regional energy resource plan**	N/A	N/A
Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources			
7	Utility throughput incentive is addressed and disincentives are removed	6	4
8	Utility incentives for energy efficiency savings reviewed and established as necessary**	N/A	N/A
9	Timely cost recovery in place**	N/A	N/A
Goal Three: Establishing Cost-Effectiveness Tests			
10	Cost-effectiveness tests adopted which reflect the long-term resource value of energy efficiency	26	8
Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms			
11	Robust, transparent EM&V procedures established	12	12
Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms			
12	Administrator(s) for energy efficiency programs clearly established	18	10
13	Stable (multi-year) and sufficient funding in place consistent with energy efficiency goals	6	8
14	Programs established to deliver energy efficiency to key customer classes and meet energy efficiency goals	17	11
15	Strong public education programs on energy efficiency in place**	N/A	N/A

Figure 2-1. Progress in Meeting Implementation Goals: Strawman Approach for Electricity Services*

	Implementation Goal and Key Steps: Electricity Services	States Having Adopted Policy or Step as of 2007	
		Completely	Partially
16	Energy efficiency program administrator(s) engaged in developing and sharing program best practices at the regional and/or national level	26	0
Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices			
17	State policies require routine review and updating of building codes	32	6
18	Building codes effectively enforced**	N/A	N/A
19	State appliance standards in place	10	0
20	Strong state and local government lead-by-example programs in place	13	24
Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency			
21	Rates examined and modified considering impact on customer incentives to pursue energy efficiency	6	3
22	Mechanisms in place to reduce consumer disincentives for energy efficiency (e.g., including financing mechanisms)	3	6
Goal Eight: Establishing State of the Art Billing Systems			
23	Consistent information to customers on energy use, costs of energy use, and options for reducing costs**	N/A	N/A
Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems			
24	Investment in advanced metering, smart grid infrastructure, data analysis, and two-way communication to enhance energy efficiency	14	28
25	Coordinated energy efficiency and demand response programs established by customer class to target energy efficiency for enhanced value to customers	10	0
26	Programs established to use trained and certified professionals as part of energy efficiency program delivery**	N/A	N/A
Goal Ten: Implementing Advanced Technologies			
27	Policies in place to remove barriers to clean, efficient distributed generation	2	28
28	Timelines developed for the integration of advanced technologies**	N/A	N/A

* See Appendix D for additional information on how these numbers have been determined.

** See Appendix D for discussion of why progress on this policy step is not currently measured.

*** N/A—Not Available

Figure 2-2. Progress in Meeting Implementation Goals: Strawman Approach for Natural Gas Services*

Implementation Goal and Key Steps: Natural Gas Services		States Having Adopted Policy or Step as of 2007	
		Completely	Partially
Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource			
1	Process in place, such as a state and/or regional collaborative, to pursue energy efficiency as a high-priority resource	9	0
2	Policy established to recognize energy efficiency as a high-priority resource	6	0
3	Potential identified for cost-effective, attainable energy efficiency over the long term	5	0
4	Energy efficiency savings goals established consistent with cost-effective potential	3	2
5	Energy efficiency savings goals integrated into state energy resource plan, with provisions for regular updates	2	4
6	Energy efficiency savings goals integrated into a regional energy resource plan**	N/A	N/A
Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources			
7	Utility throughput incentive is addressed and disincentives are removed	5	11
8	Utility incentives for energy efficiency savings reviewed and established as necessary**	N/A	N/A
9	Timely cost recovery in place**	N/A	N/A
Goal Three: Establishing Cost-Effectiveness Tests			
10	Cost-effectiveness tests adopted which reflect the long-term resource value of energy efficiency	10	2
Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms			
11	Robust, transparent EM&V procedures established	3	2
Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms			
12	Administrator(s) for energy efficiency programs clearly established	11	4
13	Stable (multi-year) and sufficient funding in place consistent with energy efficiency goals	1	5
14	Programs established to deliver energy efficiency to key customer classes and meet energy efficiency goals	5	5
15	Strong public education programs on energy efficiency in place**	N/A	N/A

Figure 2-2. Progress in Meeting Implementation Goals: Strawman Approach for Natural Gas Services*

	Implementation Goal and Key Steps: Natural Gas Services	States Having Adopted Policy or Step as of 2007	
		Completely	Partially
16	Energy efficiency program administrator(s) engaged in developing and sharing program best practices at the regional and/or national level	13	0
Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices			
17	State policies require routine review and updating of building codes	32	6
18	Building codes effectively enforced**	N/A	N/A
19	State appliance standards in place	10	0
20	Strong state and local government lead-by-example programs in place	13	24
Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency			
21	*Rates examined and modified considering* impact on customer incentives to pursue energy efficiency	1	0
22	Mechanisms in place to reduce consumer disincentives for energy efficiency (e.g., including financing mechanisms)	0	0
Goal Eight: Establishing State of the Art Billing Systems			
23	Consistent information to customers on energy use, costs of energy use, and options for reducing costs**	N/A	N/A
Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems			
26	Programs established to use trained and certified professionals as part of energy efficiency program delivery**	N/A	N/A
Goal Ten: Implementing Advanced Technologies			
28	Timelines developed for the integration of advanced technologies**	N/A	N/A

* See Appendix D for additional information on how these numbers have been determined

** See Appendix D for discussion of why progress on this policy step is not currently measured

*** N/A—Not Available

Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources

Progress can be measured as the following steps are achieved:

7. **Utility throughput incentive is addressed and disincentives are removed.** Under conventional ratemaking, utilities have typically been compensated based on the volume of energy delivered to customers; this creates a disincentive for investing in efficiency, which reduces throughput. Removing this disincentive so that utilities are indifferent to selling energy or saving energy is an important step.

8. **Utility incentives for energy efficiency savings reviewed and established as necessary.** Removing the disincentive that many utilities have to save energy (see #7) is important but not necessarily sufficient to fully align utility incentives behind the delivery of cost-effective energy efficiency. Utilities may need other incentives to view energy efficiency on an equal playing field with supply options. It may be important to review the existing utility incentive structure and to provide incentives, linked to performance, to spur greater investment in energy efficiency where it is cost-effective, or to ensure appropriate shareholder incentives are in place in similar to those associated with generation options.

9. **Timely cost recovery in place.** A basic requirement for the elimination of disincentives to energy efficiency programs is establishing a fair, expeditious process for recovery of costs. Failure to recover program costs directly negatively affects a utility's cash flow, net operating income, and earnings. Further, lack of timely cost recovery increases regulatory risk and requires the utility to incur carrying costs.

Goal Three: Establishing Cost-Effectiveness Tests

Progress can be measured as the appropriate state agencies accomplish the following step:

10. **Cost-effectiveness tests adopted which reflect the long-term resource value of energy efficiency.** Energy efficiency can provide long-term benefits to an energy system when it costs less to save a watt or a therm than it does to deliver one, particularly when the energy savings are accumulated over time and the costs of new power plants and transmission can be avoided. Cost-effectiveness tests that reflect these long-term benefits help stakeholders set goals and develop programs to put them on a path to capturing all cost-effective energy efficiency.[7] As an example, the total resources cost test compares the total costs and benefits of an efficiency program, including benefits to the utility and all participants and avoided costs of energy supply. Cost-effectiveness tests may also require establishing values for saved energy (kWh or therms) and capacity (kW or decatherms/day). These values may account for a variety of costs and risks including the costs of all supply options, including losses, and risks associated with permitting, construction, operation; costs and risks of fuel supplies, costs and risks of environmental regulations. They may also include the social value of low-income programs, if applicable.

Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms

Progress can be measured as the following step is achieved:

11. **Robust, transparent evaluation, measurement, and verification procedures established.** Robust and transparent EM&V serves a number of objectives including: (1) measuring and documenting the impacts of a program and how well it met its goals with respect to being a reliable energy resource, (2) helping to identify ways to improve current and future programs, (3) determining the cost-effectiveness of a program, and (4) when public or ratepayer funds are involved, documenting compliance with regulatory requirements. Establishing robust and transparent EM&V approaches will, over time, also contribute to greater

consistency in EM&V across utilities, programs and states; which will reduce the burden on individual program developers to establish such protocols, and build consistent understanding of proven efficiency programs that can participate in regional and national markets. Most existing efficiency programs have some form of EM&V, but improving those programs and standardizing them over time are a key part of the Vision. EM&V of energy efficiency may also become a feature of grid modernization programs where real-time monitoring and evaluation of energy use is achieved.

Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms

Progress can be measured as the following steps are achieved:

12. **Administrator(s) for energy efficiency programs clearly established.** There are variety of successful program models for delivering energy efficiency which use different types of program administrators. These types include utilities, state agencies (e.g., NYSERDA), third parties (e.g., Efficiency Vermont), or a combination of administrator types. Clearly establishing parties to administer energy efficiency programs is an important step.

13. **Stable (multi-year) and sufficient funding in place consistent with energy efficiency goals.** It is critical to establish adequate, multi-year funding to support the energy efficiency program measures, consistent with the established energy savings target and cost-effective potential. Multi-year funding more easily allows longer-term planning and development of programs, particularly ones that have some upfront costs to access the larger energy savings in a customer group. There are many funding mechanisms that have been applied for different program structures. Funding might be through a systems benefit charge, another rate mechanism, or rate-based recovery mechanisms such as revenue requirement funding or resource procurement funding.

14. **Programs established to deliver energy efficiency to key customer classes and meet energy efficiency goals.**[8] There are significant cost-effective energy savings to tap into through well-designed energy efficiency programs across the key customer classes, for both new and existing buildings, and there are many successful efficiency programs providing reliable results which serve as best practice models for new programs. A robust efficiency program portfolio that provides broad access to energy savings is the linchpin of a successful energy efficiency effort.

15. **Strong public education programs on energy efficiency in place.** Public education is an important element of encouraging customers to take advantage of available energy efficiency programs as well as to take greater control of their energy costs through energy saving measures they can undertake themselves. Many states and utilities have public outreach efforts, but greater integration with energy efficiency programs, both at the state and regional level, and leveraging the national ENERGY STAR® platform can increase overall effectiveness.

16. **Energy efficiency program administrator(s) engaged in developing and sharing program best practices at the regional and/or national level.** Sharing of best practices in program design, implementation, and evaluation as well as keeping current on emerging technologies and practices as an important part of maintaining well-designed, cost-effective programs and potentially enhancing the consistency of energy efficiency programs offered across a state and region. Coordination at the national level such as that offered by the Consortium for Energy Efficiency can be important to effectively engage with national organizations such as manufacturers, retailers, and others that are essential for effective energy efficiency programs. Coordination and sharing of best practice at the regional level (e.g., through NEEP, NEEA, SWEEP, MEEA, and SEEA) is also important to improve the

consistency in energy efficiency programs offered across a region and to help reduce program costs.[9] This coordination can be especially effective when utilities serve multiple states in the region. The Edison Electric Institute's newly formed Institute for Energy Efficiency will provide another forum for best practice sharing.

Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices

Progress can be measured as the following steps are achieved:

17. **State policies require routine review and updating of building codes.** New construction and major renovations represent cost-effective opportunities to incorporate energy-efficiency measures into buildings because these improvements save energy throughout the life of those buildings and can be expensive to adopt later. Building energy codes specify a series of efficiency measures including construction practices and technologies that have been shown to yield cost-effective savings, providing a minimum set of requirements. Building energy codes are typically developed at the national level, adopted at the state level, and implemented and enforced by local governments. Having up-to-date building codes in place is an important part of realizing the energy savings in new construction and major renovation.

18. **Building codes effectively enforced.** Up-to-date, implemented, and enforced energy codes can lock in cost-effective energy savings of 30 percent or more at the time of building construction relative to typical practices,[10] lowering costs for businesses and consumers. Seeing that the necessary training and enforcement of building codes is in place is an important part of realizing the savings that building codes offer.

19. **State appliance standards in place.** State appliance efficiency standards establish minimum energy efficiency levels for appliances and other energy-consuming products (if those appliances have not already been addressed by federal efficiency standards). These standards typically prohibit the sale of less-efficient models within a state. Many states have implemented appliance and equipment efficiency standards for products not addressed by the federal government.

20. **Strong state and local government lead-by-example programs in place.** State and local lead-by-example initiatives include a range of programs and policies that advance the use of clean energy within their own facilities, fleets, and operations. In pursuing lead-by-example strategies, states can leverage their purchasing power, their control of significant energy-using resources, and the high visibility of their public facilities to demonstrate clean energy technologies and approaches that lower their energy costs and reduce emissions. Strong programs involve establishing goals and the processes necessary to implement them and report on progress. Energy efficiency program administrators can be important partners in helping governments achieve their goals (EPA, 2006).

Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency

Progress can be measured as the following steps are achieved:

21. **Rates examined and modified considering impact on customer incentives to pursue energy efficiency.** Rate designs with clear and meaningful price signals to customers, coupled with good customer education, can encourage energy efficiency from the consumer side. For example, removing "declining block" rate structures that discourage energy efficiency by decreasing costs as more electricity or natural gas is consumed may be an initial step.

22. **Mechanisms in place to reduce customer disincentives for energy efficiency (e.g., including financing mechanisms).** Electricity and natural gas rates can also be partnered with other mechanisms that encourage energy efficiency, such as benefit sharing programs and on-bill financing. These mechanisms help provide the financing that

the customer may need to pursue an energy efficiency measure.

Goal Eight: Establishing State of the Art Billing Systems

Progress can be measured as the following step is achieved:

23. **Consistent information to customers on energy use, costs of energy use, and options for reducing energy costs.** Providing customers with clear information on their energy use, the costs of energy use, and the variety of options available for reducing their costs is an important part of the Vision. Further, greater consistency in how energy use and cost information is provided to customers would assist customers with properties in more than one service territory. And greater ability to access data on their energy use for several years at time as well as ability to access electronic versions of the data would assist many customers. This step has resulted from the Sector Collaborative for Energy Efficiency of the National Action Plan (National Action Plan for Energy Efficiency, 2007).

Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems. Progress can be measured as the following steps are achieved:

24. **Investment in advanced metering, smart grid infrastructure, data analysis, and two-way communication to enhance energy efficiency.** Many utilities are studying, piloting, or deploying advanced metering as part of grid modernization, and many millions of advanced meters are now on order for installation over the next five years. Advanced metering, combined with communication, energy information collection systems, and time-based rates, can be used to help identify and promote energy efficiency opportunities, in addition to enhancing system reliability and reducing peak demands These technologies enable demand response, automated energy management, and better data collection for load analysis and program evaluation. Two-way communications between the grid and the customer and their energy-using devices help reap the full value of advanced meters and automate the operation of buildings and energy-using devices in ways that save energy and reduce peak loads. Exploration of these opportunities and investment as the business case can be made is a key step in the Vision.

25. **Coordinated energy efficiency and demand response programs established by customer class to target energy efficiency for enhanced value to customers.** Energy efficiency programs aim primarily to reduce total electricity usage (kWh), and demand response programs aim to change customers' usage patterns in response to price signals or incentives that vary over time. Demand response programs today are targeted primarily toward reducing peak load or total demand at times of system emergency when load relief is needed; in the longer term, demand response technologies can enable round-the-clock, automated customer energy management that is interactive with the grid. Customers participating in demand response programs may also reduce their energy consumption[11] and invest in energy efficiency improvements that save kWh and peak demand usage. Coordinated, complementary energy efficiency and demand response measures will be valuable for energy customers and important to achieving the Vision goals.

26. **Programs established to use trained and certified professionals as part of energy efficiency program delivery.** Energy efficiency programs play a vital role in increasing the availability of qualified energy professionals for quality program delivery through training and certification. Further, programs using certified technicians from accredited companies can conduct a whole-building assessment and recommend and professionally install comprehensive improvements that yield the best results in energy efficiency, comfort, health and safety, and building durability.

Goal Ten: Implementing Advanced Technologies

Progress can be measured as the following steps are achieved:

27. **Policies in place to remove barriers to clean, efficient distributed generation.**[12] Clean, efficient distributed generation resources are an important component of an integrated energy resource plan. Coordinated policies (such as interconnection rules, reviewing clean, efficient distributed generation as part of the planning process and incorporating it where effective, and standby rates) that remove barriers to these technologies, including solar photovoltaic and combined heat and power, are valuable toward achieving this integration.

28. **Timelines developed for the integration of advanced technologies.** To ensure integration of advanced technologies and their adaptation into the broader resource plans, utilities and their regulators are encouraged to work collectively to review advanced technologies and determine rapid integration timelines.

Beyond the implementation of the ten goals and the steps to take, progress will also be measured in terms of key benefits from their adoption and the investment necessary, including:

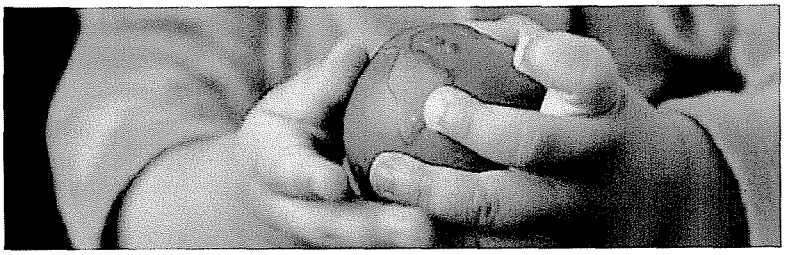
- Energy to be saved through energy savings goals (kWh, kW, and therms).
- Energy saved (kWh, kW, and therms).
- Carbon dioxide emission reductions.
- Dollars invested in energy efficiency programs.
- Cost-effectiveness of energy efficiency program delivery.

As part of their continued facilitation of the National Action Plan for Energy Efficiency, EPA and DOE are prepared to facilitate the measurement of progress under the Action Plan in conjunction and coordinate with other organizations.

Notes

1. These savings are consistent with the potential savings documented in a number of recent studies. See Appendix B for references for these studies. Appendix C includes information on how these benefits were derived.
2. Net savings equals the savings from reduced electricity purchases and capital expenditures by the utility minus utility and participant costs of energy efficiency. Value is given in net present value, assuming a 5 percent discount rate.
3. "Utilities" refers any organization that delivers electric and gas utility services to end-users, including investor-owned, cooperatively owned, and publicly owned utilities.
4. See the findings of the Sector Collaborative for Energy Efficiency for additional information (via <www.epa.gov/eeactionplan>).
5. The Action Plan's report has a number of examples of successful collaborative efforts. Examples can be found on the following pages: 2-14, 3-6, 3-8, 6-13, 6-25. The report also lists several best practices to follow when soliciting stakeholders' input on page 6-32.
6. See the reports of the Western Governors' Association's Clean and Diversified Energy Advisory Committee: <http://www.westgov.org/wga/initiatives/cdeac/cdeac-reports.htm>.
7. For more information on cost-effectiveness tests, see the Action Plan Guides on Resource Planning with Energy Efficiency and Conducting Potential Studies.
8. See Chapter 6, "Energy Efficiency Program Best Practices," of the Action Plan's report (National Action Plan for Energy Efficiency, 2006).
9. There are a number of regional energy efficiency coordination organizations across the country. They include the Northeast Energy Efficiency Partnership (NEEP), the Northwest Energy Efficiency Alliance (NEEA), the Midwest Energy Efficiency Alliance (MEEA), the South West Energy Efficiency Partnership (SWEEP), and the new Southeast Energy Efficiency Alliance (SEEA).
10. Determined using a BCAP calculator that compares each state's current code to the 2006 IECC for residential and commercial construction. The sum of savings in all 50 states produces a 30 to 40 percent savings range.
11. Based on a survey of over 100 demand response programs, the effect of demand response programs on total energy consumption was found to range from increasing total energy use by 5 percent to achieving total energy savings in excess of 20 percent (King and Delurey, 2005).
12. The term "clean distributed generation" is used in this document to mean distributed generation that is cleaner than the average central station power plant.

3: The Vision for 2025



The long-term goal for the Vision for the National Action Plan for Energy Efficiency is to achieve all cost-effective energy efficiency by 2025. As energy efficiency policies are pursued, the energy system is modernized, and new technologies emerge, there will be a lower-cost, more reliable energy system with significant environmental benefits. The energy system that offers these benefits is likely to look very different than the one we have today.

A Look at 2025

By 2025, the energy system would focus on providing energy services rather than energy supply, energy providers would see energy efficiency as an important business area, a vibrant energy efficiency services industry would be in place, there could be greater reliance on clean distributed generation, and the system would be modernized to facilitate appropriate price signals and digital communication, analysis, and system control. It would be very different in terms of how consumers receive and value energy services. Additional description of some of the key differences in 2025 is provided below and illustrated in Figure 3-1. This includes a discussion of some of the challenges and emerging technologies critical to meeting the long-term goal of the Vision.

Energy Customers

Customers across the residential, commercial, and industrial sectors will have new opportunities and experiences with energy efficiency services, energy information, and energy system interactions. They will be offered a variety of innovative energy service packages to help them manage their energy use and costs better, including universal access to comprehensive energy efficiency services. These services will routinely assess the energy efficiency of homes, buildings, and industrial plants and help customers undertake low-cost energy efficiency improvements, access high-quality contractors, and access financing where necessary. Customers will also have clear information on their use and costs of energy and more options for lowering their energy bills by allowing building appliances and controls to help meet peak energy demands. For example, with advanced meters, time-of-use information about energy prices, and automated devices to control their energy usage, customers will face higher energy costs when energy costs more to provide but be able to avoid some of these costs through advances in two-way communication and grid-connected controls, appliances, and equipment.

Customers will have lower energy bills in 2025 than if cost-effective energy efficiency programs were not pursued. Based on technologies and practices available, today many individual homes and buildings can be improved by 20 percent or more, and many industrial plants can be improved by 10 percent or more.[1] These savings are being achieved through well-designed energy efficiency programs and policies that deliver a variety of technologies and practices. Some of the approaches that can substantially lower the costs of energy in existing and new homes, buildings, and industries include:

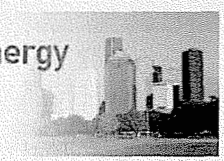
- **Homes:** There are a variety of proven programs delivering energy savings to many types of homes. These programs range from product-based incentive programs to whole-home audit and improvement programs that use trained, certified home professionals. These programs are providing home energy savings of 20 percent savings or more and up to 50 percent.[2,3] Improvements include greater insulation and air sealing, efficient lighting and appliances, efficient windows, properly sized and installed heating and air conditioning, low-standby home products, and efficient water heating. In addition, controls such as programmable thermostats deliver significant savings when used properly. Programs are also resulting

Figure 3-1. Achieving All Cost-Effective Energy Efficiency: Key Perspectives



Home Energy Savings: 20% to 50%*

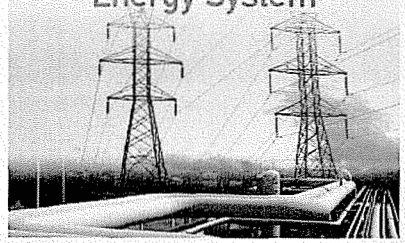
- Efficient home envelope: insulation and air sealing
- Tight ducts
- Efficient windows
- Efficient, properly sized and installed heating and cooling equipment
- Efficient lighting and appliances
- Low-standby energy use
- Verification of home energy efficiency
- Grid-connected controls and appliances
- Good information on energy use, costs of energy, and savings opportunities
- Whole-building design to achieve greater energy savings



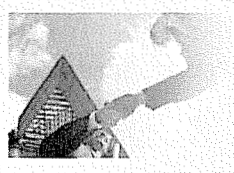
Building Energy Savings: 20% to 50%*

- Energy-efficient equipment
- Low-standby energy
- Efficient lighting systems using good design, controls, daylighting, and efficient technology
- Properly sized, efficient, and controlled cooling and heating
- Commissioning and recommissioning
- Routine assessment of building energy performance
- Grid-connected controls and equipment
- Good information on energy use, costs of energy, and savings opportunities
- Whole-building design to achieve greater energy savings

Energy System

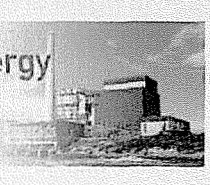


- Pursue all cost-effective energy efficiency resources
- Universal efficiency services across all customer classes
- Enhanced use of clean distributed generation
- Modernized grid supports greater data analysis, customer control, utility control of peak-driving equipment, self-healing capabilities



Net Benefits

- Lower energy bills
- Environmental benefits
- Lower greenhouse gas emissions
- Enhanced reliability through reduced peak demands
- Assistance to low-income and elderly customers
- Economic benefits from new jobs and growing local services industry
- Increased fuel diversity to meet U.S. electric load



Industry Energy Savings: 10% or More*

- Energy-efficient equipment
- Efficient lighting systems using good design, controls, daylighting, and efficient technology
- Efficient motor systems
- Manufacturing processes tuned for energy efficiency
- Waste heat recovered and utilized
- Good information on energy use, costs of energy, and savings opportunities

*These are savings on a per facility basis, reflecting the energy consumption savings possible to new and existing homes and buildings based on information available today; these savings could be larger in the future based on development from a range of ongoing research and development efforts.

in the construction of new homes that use substantially less energy than today's homes and go beyond local codes; some organizations have set goals for net zero energy homes by 2015 to 2020.[4]

- **Buildings:** There are a variety of proven programs for delivering energy savings to commercial and institutional buildings as well—public and private office buildings, schools, hospitals, hotels, and others. Proven energy efficiency programs assist with building system improvements, training of building operators, commissioning and recommissioning of buildings, and routine assessment of building energy use. These programs offer savings of 20 percent or more at the building level.[5] They deliver technologies such as optimized, efficient lighting systems employing controls and day lighting; properly sized and efficient heating and cooling equipment; and low-standby and otherwise efficient products and equipment. Additional savings can be achieved when constructing a new building, and some organizations have energy savings goals of 50 percent or more for newly constructed buildings.[6] Additional savings can be achieved from two-way information communications that let customers see and respond to the true costs of service for their building energy use.

- **Industry:** There are also a variety of programs available for the industrial sector, including equipment-specific programs, systems optimization assistance, performance contracting, financial incentives, and low-interest financing. These programs are identifying and achieving energy savings of 10 percent or more.[7] The efforts target high-energy-consuming equipment including air compressors, boilers, motors, furnaces, chillers, cooling towers, fans, pumps, and refrigeration for replacement, tune-up, and enhanced maintenance. Some programs also help utilize waste heat through combined heat and power applications and industrial process optimization.

Society

Society will benefit environmentally and economically from achieving all cost-effective energy efficiency and integrating it into a modernized energy system. Such a modernized system, with more options for meeting peak demand, will provide greater reliability and have lower costs. Energy prices will be lower than otherwise since the most cost-effective resource, on the demand or supply side, will be used first, both in planning and day-to-day operations. This system will also have lower vulnerability to disruptions, such as supply curtailments from natural disasters due to greater use of demand-side resources.

Wiser use of natural gas and electricity also has a number of environmental benefits. These benefits include lower air pollution and reduced emissions of greenhouse gas, lower water use, and a lower environmental impact from fossil fuel extraction. Importantly, it offers a low-risk, low-cost approach to address climate change emissions between now and 2025 as decision-makers continue to discuss the level of reductions on greenhouse gas emissions that are necessary. By 2025, depending on the generation sources at the local level and whether efficiency has displaced existing generation or new generation, millions of tons of emissions of carbon dioxide will be prevented from entering the atmosphere, tons of reductions that would cost much more to go back and capture in 2025.

Greater investment in energy efficiency also helps create jobs, improve local economies, and assist low-income populations. Energy efficiency programs can create construction and installation jobs, with positive impacts on employment and local economies, and the savings from energy efficiency are often redirected to other activities that increase local and national employment (Kushler et al., 2005; NYSERDA, 2004; Goldstein, 2007). Local investments in energy efficiency can also lead to more sustainable local economies, requiring less power from elsewhere, as well as reducing load on overly taxed transmission systems; and it can create valuable long-lasting infrastructure changes to building, equipment and appliance stocks (Innovest, 2002). Low-income populations can also benefit when energy efficiency programs are effectively delivered and help relieve some of the financial pressures on these customers. However, it may be important to target specific measures and market transformation efforts toward the low-income

and other "hard-to-reach" groups to address social equity issues with those customers that may have had less access to specific efficiency benefits.

Further, this is a future that would spur greater technology innovation and increase the opportunity for a growing U.S. clean energy technology industry. A more energy-efficient economy benefits the entire U.S. population, with higher productivity from fewer units of energy consumed, fewer dollars spent on energy, and less air pollution.

Evolving Policies and Technologies

Achieving the ten implementation goals by 2015 to 2020 would create an energy efficiency picture in 2025 with a number of important features, as summarized above and highlighted in Figure 3-2. There are a number of challenges to achieve this Vision, including the necessary evolution of technology, policy, and program practices. Some of these evolving areas are described below, followed by an overview of what developments to look for as progress is made (see Figure 3-3).

Regional Resource Planning

In some regions, there is growing focus on energy resource planning at the regional level or regional resource planning (RRP), with the development of regional wholesale markets and regional transmission organizations, the need for new regional interstate transmission, and the need to respond to policies promulgated by FERC and DOE (Roseman and Hochstetter, 2007). RRP is the planning and evaluation of new major generation, transmission, and demand-side resource investments based on their regional and state effects on electricity service, reliability, and rates. A regional view helps identify the value from demand and energy reductions that a more localized perspective could miss. It may be an effective planning process that can inform state and local energy efficiency planning processes and serve a valuable complementary role without superseding local activity or options.

Evaluation, Measurement, and Verification Procedures

Robust EM&V is essential to the success of achieving all cost-effective energy efficiency. EM&V measures and documents the impacts of an energy efficiency program, allowing energy efficiency to be a reliable energy resource. Effective EM&V protocols are consistent and accurate, allow for transparent evaluation of energy savings and emission reductions, and are independently administered (Schiller Consulting, 2007). While a variety of the EM&V protocols in use today may be useful and credible, a more consistent, standardized set of independently administered protocols would facilitate greater reliance on energy efficiency as a resource in regional and national energy, capacity, and ancillary service markets.

Additional attention is necessary to reach this milestone. Importantly, several developments may push EM&V protocols in this direction. New requirements are being developed for energy efficiency to participate in regional energy markets. Another development is new requirements for greenhouse gas regulations at the state and regional level. This may extend internationally as well, as interest grows in having consistent approaches for measuring energy savings and the related avoided greenhouse gas emissions across country borders. Further, by 2025, EM&V protocols may benefit from the wider deployment of measurement technology at customers' premises which may produce data on energy efficiency savings. This technology may improve the quality of EM&V, raise the level of savings credited to efficiency as conservative estimates are replaced by more accurate data, reduce the costs of delivering energy efficiency through advanced diagnostics, and reduce the costs of EM&V.

Demand Response, Advanced Metering, and Smart Grids

These technologies can make a valuable contribution to achieving the goals of the Vision. Demand response and grid technologies, programs, and pricing can help reduce overall energy use when designed with this goal in mind. Measures of interest include time-of-use pricing, advanced meters, power quality management, load management devices like "smart" thermostats, and

distributed generation (also see DOE, 2003). As demand response programs become more established and offer financial, operational, energy, and environmental benefits, more utilities and states are expected to develop these types of programs. Right now, states are addressing EPAct 2005 requirements to investigate time-based pricing and advanced meters. As the development and implementation of demand response programs require customer contact and education, these efforts can be combined with efforts to explore energy efficiency programs for greater energy savings and peak reductions. Continued exploration of how to best coordinate energy efficiency and demand response programs, as these technologies evolve, will be important.[8] It is also important to encourage smart grid interoperability[9] and coordination between and across utilities and regions.

Building Energy Efficiency Expertise/ Workforce

The large-scale ramp-up in energy efficiency programs and services described in this Vision requires the efforts of a diverse set of professionals well-versed in a many aspects of energy efficiency. Many believe that successfully investing in energy efficiency as a key component of the nation's energy mix requires substantial additional investment in trained personal in a number of areas, including:

- Policy-makers and planners
- Program designers and implementers
- Energy service contractors
- Evaluators
- And more

Figure 3-2. Important Features of Energy Systems and Services in 2025 to Achieve All Cost-Effective Energy Efficiency

- Universal energy efficiency services provided across residential, commercial, and industrial sectors
- Funding for energy efficiency programs that is consistent with cost-effective potential and allows for multiyear program planning
- Utility incentives aligned with the delivery of cost-effective energy efficiency
- Energy savings (capacity and energy) from efficiency programs integrated into long-term state/regional resource plans
- Consistent, robust, and independent evaluation, measurement, and verification of energy efficiency programs in place
- Strong public education on energy efficiency benefits and opportunities
- Updates to building codes to reflect the current cost-effective potential; enforcement of the updated codes
- Strong state, local, and federal government lead-by-example energy efficiency programs
- Energy bills that provide consistent information on energy use and costs, reflect true cost of service, and provide appropriate price signals
- New financing mechanisms for a variety of energy efficiency measures and services
- Modernized energy systems, including advanced meters, that enable demand-side resources; energy-efficient appliances and building controls that are connected to the electric grid
- Energy efficiency and demand response programs delivered in a coordinated manner
- Training on energy efficiency expertise in utility, regulatory, and private sectors
- Cost-effective, clean, efficient distributed generation integrated into energy resource plans
- Integration of R&D, building codes, appliance standards, and market transformation efforts

Figure 3-3. Overview of Evolving Technologies and Practices

Policy Area	Now	Long Term	Changes to Watch
Evaluation, measurement, and verification	• Robust, transparent procedures established	• Consistent EM&V approaches across the United States • Independent administered EM&V	• Development of national standards • Requirements for independent verification • Growing role for smart grid technologies in EM&V • Requirements for state and regional carbon programs
Demand response, advanced metering, and smart grids	• Customer energy use is not routinely linked to the energy system	• Consistent energy use and energy cost information available to all customers • Customers connected with two-way electricity grid • Delivery of energy efficiency enhanced through diagnostics	• New technologies, such as advanced meters and smart appliances/controls • Data collection networks and data analysis to enhance energy efficiency • New customer interfaces • Increased interoperability
Regional resource planning	• State-level resource planning • Some regional energy efficiency program coordination • Federal policies at FERC and DOE	• Regional coordination informs state-level resource planning	• Regional value of energy efficiency identified
Building energy efficiency expertise/workforce	• Some established protocols and certification programs for key industry services • Some curriculum for universities and community colleges	• Robust energy efficiency industry across policy, planning, programming, and energy efficiency services	• Development and use of energy efficiency curriculum for various segments of the workforce • Development and broad use of training and certification programs
Integration of R&D, building codes, appliance standards, and market transformation efforts	• Some states managing programs in and across these key program areas	• States have processes to integrate R&D, updates to building codes and appliance standards, and market transformation programs	• Regional and national coordination across these efforts

Sources: PJM, 2007; CEC and CPUC, 2005; Business Roundtable, 2007; Elliott et al., 2007; Roseman and Hochstetter, 2007; Schiller Consulting, 2007; Western Governors' Association, 2006.

While there have been important developments in these areas—such as programs focusing on quality installation, new training and certification programs for home contractors, and new curricula for colleges and universities—more work is necessary to assess the workforce infrastructure required to support the robust energy efficiency industry envisioned in 10 or more years, and to see that the necessary training is provided.

Integration of R&D, Building Codes, Appliance Standards, and Market Transformation Efforts

While there is significant cost-effective potential for meeting growing energy demand through energy efficiency and demand response technologies and practices in the coming years, technology continues to evolve and produce new opportunities for additional energy savings. Effectively taking advantage of these emerging opportunities requires coordination of the results of these R&D efforts with other key policy areas such as building codes, appliance standards, and market transformation programs. Further, the findings and results from delivering energy efficiency programs can inform the development of R&D strategies. Successful coordination across all of these efforts is important to increasing the overall benefits that energy efficiency can provide.

Notes

1. Sources are provided in the following notes for each of the key sectors: residential, commercial, and industrial. Additional sources on cost-effective opportunities for energy savings across these sectors can be found in Appendix B.

2. Home Performance with ENERGY STAR is an example of a whole home improvement program offering 20 percent, and up to 50 percent, savings per home and currently being implemented in more than a dozen jurisdictions around the country.

3. Nadel et al. (2004) found the median achievable potential for the residential sector is 26 percent; EPA analysis shows that the typical home can save about 30 percent on home energy bills through use of ENERGY STAR-qualified products. New homes are being constructed to offer savings of 20 percent from improvements to building envelopes and heating, ventilation, and air conditioning, without accounting for energy savings from plug loads such as lighting and appliances.

4. Austin Energy has announced a goal of zero-net-energy new homes by 2015; California is developing a roadmap for their new homes programs to get to zero-net-energy new homes by 2020; and the American Institute of Architects has a goal of zero-carbon new buildings by 2030, with an interim goal of 50 percent better than average buildings by 2010.

5. Nadel et al. (2004) found that the median achievable potential for the commercial sector is 22 percent. The Action Plan's Sector Collaborative found savings of 20 to 40 percent to be readily achievable in typical office buildings, hotels, and retail stores through common energy efficiency measures. EPA has information on a number of typical buildings that have been improved by 20 percent, 30 percent, or more. It also has information on more than 400 buildings that use 50 percent less energy than average buildings.

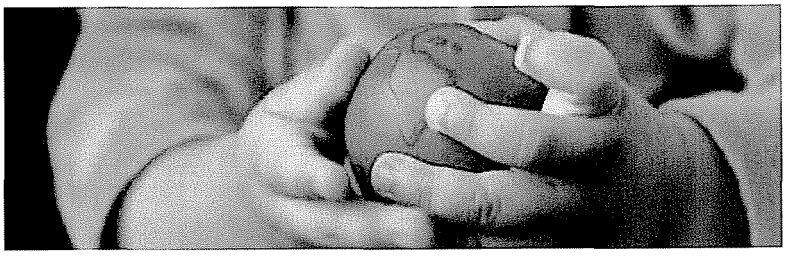
6. The American Institute of Architects has a goal of zero-carbon new buildings by 2030 with an interim goal of 50 percent better than average buildings by 2010.

7. Nadel et al. (2004) found the median achievable potential for the industrial sector is 14 percent. In addition, the DOE Save Energy Now program is identifying energy savings at the plant level of 10 percent or more across audits performed at hundreds of industrial facilities.

8. State decision-makers may want to design price-based demand response programs carefully to minimize the use of less-efficient and high-polluting distributed generation, which can negate the environmental benefits that can be achieved through demand response or energy efficiency.
(For discussion, see EPA's analysis on clean energy options for the Ozone Transport Commission High Electric Demand Day Ozone Attainment Strategies, 2006 and 2007: <http://www.otcair.org/document.asp?fview=meeting#>.)

9. See the GridWise Architecture Council <http://www.gridwiseac.org> for more information on interoperability needs and potential benefits.

4: Related State, Regional, and National Policies



A number of energy and environmental policies are being advanced at the state, regional, and national levels that have important interrelationships with the state-level energy efficiency policies of the Action Plan and the achievement of the Vision goal. These policies can be designed and implemented through a variety of approaches. Some would assist in breaking down the barriers to energy efficiency and work in conjunction with the Action Plan to help integrate cost-effective energy efficiency into a modernized energy system, while achieving other objectives. Other approaches might overlook energy efficiency and thereby lead to a higher-cost energy system than otherwise necessary.

Introduction to Policies

This chapter identifies important interrelationships between the Action Plan and five other state, regional, and federal policy areas. These policy areas are those designed to:

- Limit emissions of greenhouse gases.
- Encourage the use of clean, efficient distributed generation.
- Promote clean energy supply, such as renewable energy.
- Promote load reductions at critical peak times through demand response.
- Modernize and maintain the nation's electric transmission and distribution system, including "smart grid" and advanced meter infrastructure.
- Maintain a sufficient reserve margin for reliable electricity supply.

Policies in these areas each impact the nation's energy system and the energy customer.

Recommendations and Considerations

Key interrelationships, recommendations, and considerations for effectively integrating these efforts so that they act together to achieve the goals of the Vision are provided below.

- **Limit emissions of greenhouse gases.** Climate change is a serious environmental issue and a number of states are advancing policies to limit emissions of these gases. In addition, there are a variety of legislative proposals at the federal level. Energy efficiency is a near-term, low-cost approach for reducing emissions of carbon dioxide, the primary greenhouse gas.[1] However, particular attention needs to be paid to the design of these regulatory approaches so that they provide sufficient funding and/or incentives to overcome the market barriers that persistently limit greater investment in energy efficiency, and incorporate energy efficiency as part of the solution. If efforts are not taken to integrate cost-effective energy efficiency, carbon regulation can be expected to cost society substantially more. States and others are exploring a variety of approaches to integrating energy efficiency. It is recommended that:
  - Greenhouse gas regulation be designed to capture all low-cost carbon emission reductions available through energy efficiency by creating funding/incentives for energy efficiency programs and investments.
  - Methodologies for reporting greenhouse gas emissions be standardized and include guidance for measuring and verifying reductions from energy efficiency.

- Potential costs of reducing emissions of greenhouse gases be reflected in resource planning processes, including the application of cost-effectiveness tests for energy efficiency, where appropriate.

- **Encourage the use of clean, efficient distributed generation.** Distributed generation brings generation close to demand loads. When clean and efficient, distributed generation can help meet demand in congested areas, while lowering emissions of greenhouse gases and other pollutants and lower distribution losses. As an example, many states recognize combined heat and power as a type of clean distributed generation since it provides increased efficiency compared to grid-purchased power and on site thermal production, helps meet load in congested areas, and avoids line losses.[2] Other examples of clean distributed generation include solar and localized wind generation. Distributed generation sources can help stave off new larger generation options, reduce line losses, and help to provide alternatives to meeting existing air pollution requirements such as regulations for limiting emissions of nitrogen oxides. Some states consider output-based emission regulations for distributed generation to encourage the use of greater fuel conversion efficiency as an air pollution control measures (EPA, 2004). This is in addition to the policies included in Goal Ten of the Vision.

- **Promote clean energy supply, such as renewable energy.** Several policies help advance both energy efficiency and renewable energy. For example, clean energy portfolio standards are in place in one form or another (e.g., renewable portfolio standards, alternative energy portfolio standards) in more than half the states across the country, and discussions continue at the national level.[3] As energy efficiency is available in many parts of the country, allowing energy efficiency savings to help meet clean energy requirements can help bring clean energy into the resource mix at lower overall costs. For example, by coupling renewable energy with energy efficiency, states have found that the total cost for portfolio standards is reduced (La Capra Associates, 2006). It is recommended that energy efficiency be considered in the development of clean energy portfolio policies. In addition, a number of states are promoting distributed renewable energy such as photovoltaics. Because these systems may best contribute to the overall energy system when properly sized to meet local energy demand, it may be important to promote them as part of efforts that first reduce the demand for energy through cost-effective energy efficiency. It is recommended that cost-effective energy efficiency be explored as an important first step to programs that incentivize investment in distributed renewable energy.

- **Modernize and maintain the nation's electric transmission and distribution system.** Economic and environmental benefits from modernizing the electric grid will come from enabling demand-side resources to provide supply and ancillary services, facilitating the dispatch of the most energy-efficient supply, and reducing line losses. As advanced metering infrastructure is deployed, recognizing opportunities to leverage energy efficiency through new rate designs and customer education campaigns will increase the benefits achieved by the technology. It is recommended that advancements in grid-connected appliances, controls, transformers, energy storage, and on site generation incorporate energy-efficient design. This is in addition to the policies included in Goal Nine of the Vision.

- **Maintain a sufficient reserve margin for reliable electricity supply.** The level of investment needed by the utility sector to maintain system reliability can be lowered through the delivery of cost-effective energy efficiency, clean distributed generation, demand response, grid advancements, and advancements in storage capabilities. It is recommended that energy efficiency be recognized as a high priority resource in energy resource planning and that this suite of demand-related efforts be incorporated in resource planning and reliability efforts. Increasing investment in energy efficiency will also increase the diversity of fuels and resources used to meet electricity demand and maintain resource adequacy.

In addition to these policies, there are several technology areas to monitor under the Action Plan for inclusion in future updates. These technologies have not yet achieved enough penetration to determine how to effectively incorporate energy efficiency, but are anticipated to make significant progress over the coming years. These technologies include plug-in hybrid vehicles and "smart" appliances.

- **Plug-in hybrid vehicles.** These vehicles use the same technology as electric/gas hybrid vehicles today, but include a larger battery that can be recharged by plugging it into an electric outlet.[4] Currently, they are not mass-produced, so consumers cannot purchase them. However, many believe that they will be available on a large scale in the future, providing owners the opportunity to charge the battery with grid electricity. Studies are in place at universities to examine how plug-in hybrids might be integrated into the network to provide demand response options—using battery-charged electricity when the load curve is at its highest point, a version of pumped storage currently in use by many utilities.
- **Smart appliances.** There is increasing discussion of manufacturing appliances that communicate with the electric grid. These "smart" appliances "talk" to the grid through technology, sensing grid conditions by monitoring system frequency and providing automatic demand response in times of disruption.[5] This technology is a computer chip that can be integrated during the appliance manufacturing process. Pilots underway in the Pacific Northwest include approximately 200 homes, but this technology is not currently available on a large scale (PNNL, 2006). Many experts believe that this technology will be widely used across the country in the coming years, providing an increased opportunity to leverage energy efficiency.

Notes

1. See Appendix B for references to studies that discuss the carbon emissions savings from energy efficiency.
2. States including Connecticut, Hawaii, Maine, North Carolina, Pennsylvania, and Washington include combined heat and power as an eligible resource in their renewable portfolio standards.
3. See EPA's *Guide to Action* and policy tracking resources.
4. For more information on plug-in hybrid vehicles, visit <http://www.pluginpartners.org> or <http://www.calcars.org>.
5. For more information on "smart" appliances, visit <http://gridwise.pnl.gov/technologies> and <http://www.gridwiseac.org>.

5: Tools and Assistance to Help Realize the Vision



This chapter discusses the tools and other assistance currently available to help leading parties realize the Vision's long-term goal of achieving all cost-effective energy efficiency by 2025. A lack of familiarity with best practice policy and program options remains a key barrier to increased investment in cost-effective energy efficiency and a number of tools and resources are available to help leading parties, including regulators, utilities, state governments, consumer advocates, environmental groups, and large end-users to explore these options (National Action Plan for Energy Efficiency, 2006). Some of this assistance is available through the Action Plan and some is available through other efforts of the federal government and the private sector.

National Action Plan for Energy Efficiency Tools

A number of tools and resources have been developed under the Action Plan to assist organizations as they strive to meet their commitments under the Action Plan. These tools and resources will help state decision-makers and others achieve many of the ten implementation goals outlined in Chapter 2, as shown in Figure 5-1 and available on the Action Plan Web site <www.epa.gov/eeactionplan>.

The Leadership Group will prioritize the development of new tools and assistance based on what is needed to help parties meet the Vision goals within their company, organization, or state. In addition, materials may need to be developed to address some of the challenges to meeting the Vision outlined in Chapter 3 or to facilitate the development of other state, regional, and federal policies so that they complement the achievement of the Vision goals, as outlined in Chapter 4. The Leadership Group will consider these gaps when identifying and prioritizing the Action Plan's future activities. Additional areas for attention to address evolving policies and technologies for achieving the Vision and integrating with other state, regional, and federal policies include:

- Integration of R&D, building codes, appliance standards, and market transformation efforts.
- Integration of energy efficiency into regional energy markets.
- Training on energy efficiency expertise in the utility, regulatory, and private sectors.[1]
- State, regional, and federal carbon policies designed to encourage energy efficiency where cost-effective.

In addition to the development of tools and other resources, the Leadership Group members are helping others through peer-to-peer assistance.

Federal Government Assistance

A number of federal programs are available to encourage energy efficiency and can be crucial resources for meeting the Vision goals. EPA and DOE's ENERGY STAR program is one such resource. Nationally, ENERGY STAR provides a platform for program implementation across customer classes and defines voluntary efficiency levels for homes, buildings, and products. ENERGY STAR is a voluntary public-private partnership designed to reduce energy use and related greenhouse gas emissions. The program has an extensive network of partners including equipment manufacturers, retailers, builders, energy service companies, private businesses, and public sector organizations.

Since the late 1990s, EPA and DOE have worked with utilities, state energy offices, and regional nonprofit organizations to help leverage ENERGY STAR messaging, tools, and strategies to enhance local energy efficiency programs. Today more than 450 utilities (and other efficiency program administrators), servicing 65

Figure 5-1. National Action Plan for Energy Efficiency Tools by Implementation Goals

Goal	Type of Tool or Resource		Detailed Action Plan Tools and Resources
	Introduction to Issues in Action Plan Report	Detailed Guide/How-to Material	
Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource	X	X	• Guide to Resource Planning with Energy Efficiency • Guide for Conducting Energy Efficiency Potential Studies • Communications Kit
Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources	X	X	• Aligning Utility Incentives with Investment in Energy Efficiency Paper
Goal Three: Establishing Cost-Effectiveness Tests	X		• Guide to Resource Planning with Energy Efficiency • Guide for Conducting Energy Efficiency Potential Studies
Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms	X	X	• Model Energy Efficiency Program Impact Evaluation Guide
Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms	X	X	• Regional Implementation Meetings Resources Database
Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices		X	• Building Codes for Energy Efficiency Fact Sheet
Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency	X		
Goal Eight: Establishing State of the Art Billing Systems		X	• Sector Collaborative on Energy Efficiency; Overview of Utility Data Availability and Proposed Best Practices to Facilitate Energy Benchmarking
Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems		X	• Paper on Coordination of Demand Response and Energy Efficiency (under development)
Goal Ten: Implementing Advanced Technologies			

percent of U.S. households, participate in the ENERGY STAR program. More information on ENERGY STAR can be found at <http://www.energystar.gov>.

Two other federal resources that provide assistance for energy efficiency measures are the Low Income Home Energy Assistance Program (LIHEAP) and the Weatherization Assistance Program (WAP). The LIHEAP, administered by the U.S. Department of Health and Human Services, helps eligible low-income homeowners and renters pay their heating and cooling bills. The WAP helps reduce the energy bills of low-income households by making their homes more energy efficient. Both of these programs have proven to be very effective. Since 1999, DOE has been encouraging the network of weatherization providers to adopt a whole-house approach whereby they approach residential energy efficiency as a system rather than as a collection of unrelated pieces of equipment (DOE, 2006; National Action Plan for Energy Efficiency, 2006, pp. 6-32, 6-33).

Federal financial grants can also be used by parties to explore energy efficiency policy and program issues. DOE issues many grant solicitations throughout the year that provide funding for R&D activities, for the development of specific types of technologies, and for many other types of activities that promote energy efficiency. The U.S. Department of Agriculture sometimes issues funding for the development of energy efficiency projects that use renewable fuels or for the development of these technologies in rural areas.

There are also federal and state tax credits available for installing energy efficiency projects. Many energy efficiency program administrators are now pointing consumers and businesses to the new federal tax credits and incorporating them in their programs. In addition, program administrators can educate their customers on existing tax strategies, such as accelerated depreciation and investment tax strategies, to help them recoup the costs of their investments faster. Some states offer additional tax credits, and/or offer sales tax "holidays," where sales tax is waived at point of sale for a specified period of time ranging from one day to a year (National Action Plan for Energy Efficiency, 2006, p. 6-37).

Leveraging Other Resources

Private sector resources will be critical in achieving the Action Plan Vision for 2025. Private sector resources provide expertise, job training and certification, and additional funding and financing of energy efficiency programs and services. Many organizations provide education and training to their members, including training on energy efficiency. Working with these organizations provides access to their members, and the opportunity to leverage funding or marketing opportunities provided by these organizations (National Action Plan for Energy Efficiency, 2006, p. 6-37). Private foundations often provide grants to fund the exploration of energy efficiency policy and program issues.

In addition, a number of private firms and not-for-profit entities deliver energy efficiency programs throughout the United States or in specific regions. These firms can quickly get a program up and running, as they have the expertise, processes, and infrastructure to handle program activities. New program administrators can contract with these organizations to deliver energy efficiency program design, delivery, and/or implementation support in their service territory (National Action Plan for Energy Efficiency, 2006, p. 6-38). Also, those looking to establish an energy efficiency program can look to well-regarded programs as a reference. Utilities that are starting up or revising existing programs can look to other programs in their area or the country to utilize existing and emerging best programs. Many successful program models have emerged and are being refined to achieve even more cost-effective results (National Action Plan for Energy Efficiency, 2006, p. 6-39). The Consortium for Energy Efficiency has announced a new "Ask an Expert" initiative to help share these best practice program information beyond their membership.

Engaging All Stakeholders

To achieve the full potential for energy savings and the related societal benefits, many parties need to work together toward the Vision. Energy efficiency policies and programs affect numerous parties, including local, state,

and federal governments; utilities; customers; energy efficiency product and service providers; manufacturers; builders; architects; environmental groups; energy system operators; labor advocates; and economic development groups. Educating and soliciting input from all key parties, either through local, state, and regional collaboratives or though other outreach efforts, will greatly increase the economic and environmental benefits achieved through energy efficiency.

Notes

1. A scope of work is being developed in this area to estimate the size of the workforce required, the skills necessary, and the types of curricula or training that can help develop these skills.

Appendix A: National Action Plan for Energy Efficiency Leadership Group



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New York State Public Service Commission

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Seattle City Light

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Santee Cooper

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New York Power Authority

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Connecticut Department of Public Utility Control

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North Carolina Air Office

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Washington Utilities and Transportation Commission

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Food Lion

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U.S. Department of Energy

U.S. Environmental Protection Agency

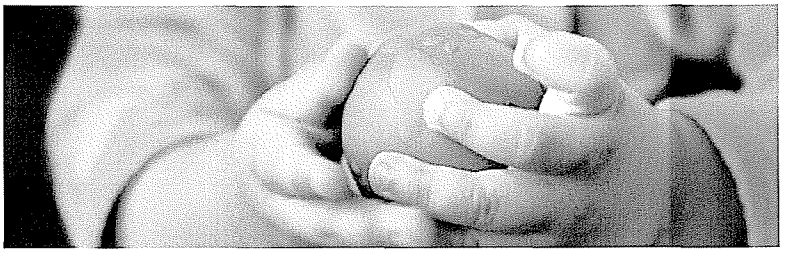
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Appendix B: Related Studies and Documents



Studies That Include the Potential Magnitude of Energy Savings From Energy Efficiency			
Author/ Source, Date	**Title**	**Magnitude Description (MWh, MW, etc.)**	**Web Site**
William R. Prindle, Anna Monis Shipley, and R. Neal Elliott (ACEEE), 2006	Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative	Doubling efficiency would cut load growth by about two-thirds in 2024, from about 20% to about 6% above 2006 levels. Electricity generation is measured in GWh; by 2024, under the reference case, generation would reach around 480,000 GWh, and with doubled efficiency it would reach around 430,000 GWh.	http://aceee.org/pubs/e064.pdf?CFID=3568249&CFTOKEN=25476090
ACEEE, 2007	Energy Efficiency Resource Standards—Summary Paper	ACEEE analysis estimates that EERS requirements now in place could reduce national electricity demand by more than 1% per year by 2013.	http://aceee.org/energy/state/utpolicy.htm
McKinsey Global Institute, 2007	Curbing Global Energy Demand Growth: The Energy Productivity Opportunity	By capturing the potential available from existing technologies with an internal rate of return of 10% or more, we could cut global energy demand by half or more over the next 15 years. Collectively, we have the potential to cut global energy demand by 135 quadrillion Btus—the equivalent of 64 million barrels of oil per day, or almost 150% of the entire U.S. energy consumption today.	http://www.mckinsey.com/mgi/publications/Curbing_Global_Energy/index.asp
Michael Rufo and Fred Coito, (XENERGY, Inc.), 2002	California's Secret Energy Surplus: The Potential for Energy Efficiency	This study examines the potential energy and peak demand savings from energy efficiency measures in California. The study finds that, if all measures that are economic were implemented, potential peak demand savings would amount to roughly 10,000 MW. Additionally, net program peak savings potential ranges from roughly 1,800 MW under current funding (business as usual) to 3,500 MW if funding is doubled (advanced efficiency), to 5,900 MW if funding is quadrupled (maximum efficiency).	http://www.ef.org/documents/Secret_Surplus.pdf

Studies That Include the Potential Magnitude of Energy Savings From Energy Efficiency

Author/ Source, Date	Title	Magnitude Description (MWh, MW, etc.)	Web Site
Optimal Energy, Inc. (Northeast Energy Efficiency Partnerships, Inc.), 2004, updated 2005	Economically Achievable Energy Efficiency Potential in New England	This paper looks at the economically achievable potential for energy efficiency in New England. If the region were to commit to fully capturing the energy efficiency potential (at an average cost of 3.1 cents per kWh) it could provide energy savings of 17,103 GWh by 2008 and 34,375 GWh by 2013—bringing energy demand back to 1993 levels. This represents a decrease in energy demand of approximately 1.38% a year, as opposed to ISO-New England's forecasted 1.2% annual increase.	http://www.neep.org/files/Updated_Achievable_Potential_2005.pdf
R. Neal Elliott, Maggie Eldridge, Anna M. Shipley, John "Skip" Laitner, Steven Nadel, Alison Silverstein, Bruce Hedman, and Mike Sloan (ACEEE)	Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs	This paper looks at the immediate and long-term future of using energy efficiency, renewables, and demand response in Texas to meet peak demand, to enhance energy security, and to sustain the state's economic growth. Across all sectors, these studies show a median technical potential of 33% for electricity and 40% for gas, and median economic potentials for electricity and gas of 20% and 22% respectively.	http://www.environmentaldefense.org/documents/6029_ACEEE_Texas_Report.pdf
Western Governors' Association, 2006	Clean Energy, A Strong Economy and a Healthy Environment: Report of the Clean and Diversified Energy Advisory Committee to the Western Governors	By adopting the WGA's best practices scenario in the 18 WGA states, load growth could be reduced by as much as 75% over the next 15 years (report published in 2006). The best practices scenario shows that it is possible to reduce electricity consumption in 2020 by 20% relative to that in the reference scenario (measured in TWh per year).	http://www.westgov.org/wga/publicat/CDEAC06.pdf
Steven Nadel, Anna Shipley, and R. Neal Elliott (ACEEE), 2004	The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S.—A Meta-Analysis of Recent Studies	This paper summarizes 11 studies on the technical, economic, and/or achievable potential for energy efficiency within the U.S. The studies show, across all sectors, a median technical potential of 33% for electricity and 40% for gas, and median economic potentials for electricity and gas of 20% and 22% respectively.	http://www.aceee.org/conf/04ss/rnemeta.pdf

Studies That Include the Potential Magnitude of Energy Savings From Energy Efficiency

Author/ Source, Date	Title	Magnitude Description (MWh, MW, etc.)	Web Site
DOE EERE, 2006	Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs, FY 2007–FY 2050	The Office of Energy Efficiency and Renewable Energy (EERE) estimates benefits for each of its nine programs in the mid-term (2010–2025) and long term (2030–2050). If the goals of EERE's investment portfolio are achieved and the corresponding market outcomes realized, nonrenewable energy consumption will drop by 8 quadrillion Btus by 2025, or about 28% of the expected incremental growth in energy demand over this time period; and by 32 quadrillion Btus by 2050, or about 78% of the expected incremental growth in annual energy demand over this time period. This results in a declining demand for nonrenewable energy consumption starting in 2030, despite a growing economy.	http://www1.eere.energy.gov/ba/pdfs/39684_01.pdf

Studies That Value the Benefits From Energy Efficiency

Author/ Source, Date	Title	Magnitude Description (MWh, MW, etc.)	Web Site
Neal Elliott and Anna Monis-Shipley (ACEEE), 2005	Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis	This study evaluates the potential reduction in natural gas consumption energy efficiency and renewable energy. It projects an annual consumer savings for energy efficiency only of $32 billion in 2010 and $54 billion in 2020.	http://aceee.org/pubs/e052full.pdf?CFID=65288&CFTOKEN=51121347
Anthony Wright, Michaela Martin, Bob Gemmer, Paul Scheihing, and James Quinn (DOE EERE), 2007	Save Energy Now: Results from the U.S. DOE 2006 Save Energy Now Assessment Initiative	DOE, through its 2006 Save Energy Now initiative, trained teams from 200 plants on ways to reduce energy use and carbon emissions. The results from this program show that individual plants can: • Cut energy bills by 10% or more each year (over $2.5 million per plant, on average). • Save an average of 17.3% of natural gas annually. • Save an average of 20,200 metric tons of CO_2 emissions annually. In all, the 200 assessments found over $500 million in potential energy savings and 4 million metric tons in potential CO_2 emissions reductions.	http://www.eere.energy.gov/industry/saveenergynow/partners/pdfs/sen_2006_results_summary_9-20-07.pdf

Studies That Value the Benefits From Energy Efficiency

Author/ Source, Date	Title	Magnitude Description (MWh, MW, etc.)	Web Site
DOE EERE	DOE's Save Energy Now Initiative Recognizes High Performing Plants	Through its Save Energy Now initiative, DOE gives manufacturers the opportunity to receive free energy assessments and recognition for energy savings. Manufacturers received awards if they reported their energy savings results within 6 months and met the criteria in one of the following categories: 1. **Energy saver plant**—more than 75,000 million Btu total energy savings or more than 7.5% total energy savings. 2. **Energy champion plant**—more than 250,000 million Btu total energy savings or more than 15% total energy savings.	http://www1.eere.energy.gov/news/progress_alerts/progress_alert.asp?aid=248
Martin Kushler, Dan York, and Patti Witte, 2005	Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest	This report identifies a number of savings/benefits from energy efficiency: 1. Potential percentage of natural gas savings by sector in key benchmark years (2006, 2010, 2015, 2020). 2. Potential percentage of electricity savings by sector in key benchmark years. 3. Projected net natural gas consumption savings (due to energy efficiency) by sector in key benchmark years (MMcf). 4. Projected net electricity consumption savings (due to energy efficiency) by sector in key benchmark years (MWh). 5. Projected net natural gas customer dollar savings (due to energy efficiency) by sector in key benchmark years. 6. Projected net electricity customer dollar savings (due to energy efficiency) by sector in key benchmark years, and some other estimates of dollar savings.	http://www.pickocc.org/publications/natural_gas/Natural_Gas_Crisis_Report.pdf
Mark Bernstein, Christopher Pernin, Sam Loeb, Mark Hanson (RAND), 2002	The Public Benefit of Energy Efficiency to the State of Massachusetts	This study estimates public benefits of energy efficiency in Massachusetts and finds that improvements in energy efficiency in the commercial, industrial, and residential sectors is associated with benefits to the state economy from 1977 to 1997 that range from $1,664 per capita to $2,562 per capita in 1998 dollars and approximately 11% lower air emissions from Massachusetts' share of local emissions from power generation.	http://www.rand.org/pubs/monograph_reports/2005/MR1588.pdf

Studies That Estimate the Carbon Reduction Benefits From Energy Efficiency

Author/ Source, Date	Title	Report Description	Web Site
Charles F. Kutscher (American Solar Energy Society), 2007	Tackling Climate Change in the U.S.: Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030	This report looks at how much energy efficiency and renewable technologies can contribute towards reducing U.S. carbon emissions to atmospheric concentrations of 450 to 500 ppm (levels desired by a number of current legislative proposals). The report summarizes the potential carbon reduction contributions from various areas: energy efficiency, concentrating solar power, photovoltaics, wind, biofuels, biomass, and geothermal. The report found that energy efficiency and renewable technologies could meet most, if not all, of the U.S. carbon emissions reductions that will be needed to help limit the atmospheric concentration of CO_2 to 450 to 500 ppm. "Approximately 57% of the total carbon reduction contribution is from energy efficiency and (EE) about 43% is from renewables. Energy efficiency measures can allow U.S. carbon emissions to remain about level through 2030, whereas the renewable supply technologies can provide large reductions in carbon emissions below current values."	http://www.ases.org/climatechange/climate_change.pdf
Ernst Worrell, Nathan Martin, and Lynn Price (Ernest Orlando Lawrence Berkeley National Laboratory), 1999	Energy Efficiency and Carbon Dioxide Emissions Reduction Opportunities in the U.S. Iron and Steel Sector	This paper focuses on the U.S. iron and steel industry and identifies cost-effective energy and carbon dioxide emissions savings that can be accomplished currently and in the short-term future. In a detailed analysis of U.S. blast furnaces and steel mills (SIC 3312 only), the authors examined over 45 specific energy efficiency technologies and measures and estimated energy savings, carbon dioxide savings, investment costs, and operation and maintenance costs for each of these measures. Based on this information, they constructed a conservation supply curve for U.S. iron and steelmaking that found a total cost-effective reduction of 3.8 GJ/t, equivalent to an achievable energy savings of 18% of 1994 U.S. iron and steel energy use and 19% of 1994 U.S. iron and steel carbon dioxide emissions.	http://www.energystar.gov/ia/business/industry/41724.pdf

Studies That Estimate the Carbon Reduction Benefits From Energy Efficiency

Author/ Source, Date	Title	Report Description	Web Site
Howard Geller, John DeCicco, and Steven Nadel (ACEEE), 1993	Cost-Effective Carbon Dioxide Reduction Initiatives	This paper proposes and analyzes ten different national energy efficiency measures that could be used to meet President Clinton's former proposal to reduce GHG emissions to 1990 levels by 2000. If these ten initiatives were undertaken, ACEEE projected, national CO_2 emissions would be reduced by nearly 9% in 2000. In addition, national energy use in 2000 would fall by 7% and consumers' energy bills would be reduced by over $50 billion that year. By 2010, CO_2 emissions would fall by 20%, national energy use would fall by nearly 17%, and consumers' energy bills would be slashed by over $160 billion per year. These reductions in CO_2 emissions, energy consumption, and energy bills are relative to projected levels based on the reference case in DOE's Annual Energy Outlook 1993.	http://www.aceee.org/pubs/e934.htm
Illinois Governor Rod R. Blagojevich Climate Change Advisory Group, 2007	Modeling of Policy Proposals	This presentation contains an estimate of reductions of $MtCO_2e$, changes in electricity sales due to implementing policies, changes in electricity generation, policies' contributions to generation growth, effects on coal generation, greenhouse gas policy impact outside Illinois, and other impacts of adopting a number of policies such as "enhanced energy efficiency programs." The presentation finds that a mixed program could reduce electricity load growth by 100%.	http://www.epa.state.il.us/air/climate change/documents/07-09-06/modeling-of-policy-proposals.ppt
Interlaboratory Working Group (Oak Ridge National Laboratory and Lawrence Berkeley National Laboratory), 1997	Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Efficient and Low-Carbon Technologies by 2010 and Beyond	This report shows the results of a study conducted by five DOE labs on the U.S. potential to reduce greenhouse gas emissions by employing energy-efficient and low-carbon technologies. The study looked at business-as-usual forecasts from the Energy Information Administration's 1997 Outlook, which projected an increase of 390 million metric tonnes of carbon (MtC) per year (from 1340 to 1730 MtC) between 1990 and 2010. The study concluded that, along with utility sector investments, a vigorous national commitment to develop and deploy energy-efficient and low-carbon technologies could cost-effectively reduce U.S. carbon emissions by approximately 390 MtC per year.	http://enduse.lbl.gov/Projects/5Lab.html

Studies That Estimate the Carbon Reduction Benefits From Energy Efficiency

Author/ Source, Date	Title	Report Description	Web Site
John Mortensen (National Renewable Energy Laboratory), 2002	Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs: FY 2003–FY 2020	The report summarizes the results of EERE's annual Government Performance and Results Act data for fiscal year 2003. The survey reviewed a number of energy, environmental, and financial metrics including carbon emissions displaced by EERE's programs. The report predicts that "By 2020, EERE's programs could reduce total fossil energy consumption by 9–15% and reduce total carbon emissions by 9–17% compared to the 'No-EE' case. Projected growth in fossil energy consumption could be reduced by 40–67% by 2020. Projected growth in carbon emissions could be reduced by 34–67% by 2020."	http://www1.eere.energy.gov/ba/pdfs/fy03_benefits_report.pdf

Studies That Discuss Existing Barriers to Greater Investment in Energy Efficiency

Author/ Source, Date	Title	Report Description	Web Site
Miriam Pye (ACEEE), 2008	Making Business Sense of Energy Efficiency and Pollution Prevention	This paper outlines a number of successful projects that have combined energy efficiency and pollution prevention technologies. The paper also highlights the benefits of energy efficiency in preventing pollution and reducing greenhouse gases, along with energy savings potential and economic benefits. An overview of barriers to energy efficiency is also provided, along with solutions to overcome these barriers.	http://www.aceee.org/pubs/ie982.htm
Ernest Worrell and Lynn Price (Lawrence Berkeley National Laboratory), 2001	Barriers and Opportunities: A Review of Selected Successful Energy-Efficiency Programs	This paper looks at barriers that prevent the implementation of energy efficiency improvements.	http://industrial-energy.lbl.gov/node/198
Johnathan Garo Koomey, 1990	Energy Efficiency in New Office Buildings: An Investigation of Market Failures and Corrective Policies	This dissertation examines policies used to encourage energy efficiency in commercial buildings. It delves into the technical evidence for market failures and other sources that prevent optimal energy efficiency measures from being used. More specifically, the paper looks at technical evidence for market failures affecting the energy efficiency of new office buildings and looks at the type of market failures and regulatory distortions, such as imperfect competition, economic non-rationality, and regulatory distortions. The paper also provides a number of corrective policies that can be used to encourage energy efficiency.	http://enduse.lbl.gov/Info/JGKdissert.pdf

Studies That Discuss Existing Barriers to Greater Investment in Energy Efficiency

Author/ Source, Date	Title	Report Description	Web Site
William H. Golove and Joseph H. Eto (Lawrence Berkeley National Laboratory), 1996	Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy Efficiency	The report discusses seven different market barriers to investment in energy efficiency: 1. Misplaced incentives. 2. Lack of access to financing. 3. Flaws in market structure. 4. Mis-pricing imposed by regulation. 5. Decision influenced by custom. 6. Lack of information or misinformation. 7. "Gold-plating" and inseparability of features.	http://eetd.lbl.gov/ea/EMS/reports/38059.pdf
Steven Nadel (ACEEE), 1997	Appliance Energy Efficiency: Opportunities, Barriers and Policy Solutions	The study reviews recent progress in improving the energy efficiency of appliances in the United States. Nonetheless, for many products in the United States, appliance energy efficiency has not progressed much in recent years due to market barriers and the lack of certain policies that would require increased efficiency. The paper presents technical opportunities for increasing the energy efficiency of appliances and discusses policies that can overcome barriers to energy efficiency.	http://www.aceee.org/pubs/a972.htm

Documents That Discuss a Vision for Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
Alliance to Save Energy, 2005	Vision 2010: The Alliance Energy Efficiency Plan	This Web site describes legislative provisions that should be implemented to improve energy efficiency in different sectors of the economy: transportation, buildings, industry, and electric and natural gas utilities.	http://www.ase.org/content/article/detail/2131
Business Roundtable, 2007	More Diverse, More Domestic, More Efficient: A Vision for America's Energy Future	The Business Roundtable report was developed by a group of chief executives of major U.S. corporations. The report describes the energy challenges the U.S. is facing today and provides specific recommendations on how to solve energy needs such as increasing the efficiency of buildings, appliances, increased use of efficient generating technologies such as CHP.	http://www.businessroundtable.org/pdf/Energy/Business_Roundtable_Energy_Report_06062007.pdf

Documents That Discuss a Vision for Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
California Energy Commission, 2007	Distributed Generation and Cogeneration Policy Roadmap for California	This report provides a vision for 2020 on how distributed generation and combined heat and power can be utilized. MWh targets are identified for different distributed generation and combined heat and power technologies. Long-term strategies and policies are discussed.	http://www.energy.ca.gov/2007publications/CEC_500-2007-021/CEC-500-2007-021.pdf
California Energy Commission and California Public Utilities Commission, 2205	Energy Action Plan II	The Energy Action Plan sets state goals and identifies policies to help meet the California's future energy needs. The specific action areas addressed in the paper are energy efficiency; demand response; renewables; electricity adequacy, reliability, and infrastructure; electricity market structure; natural gas supply; transpiration fuels; R&D; and climate change.	http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF
Representatives of the commercial building industry (DOE EERE), 2000	High Performance Commercial Buildings: A Technology Roadmap	The paper describes how to improve commercial buildings through new designs, new technologies, improved building codes and standards, and other measures.	http://www.eere.energy.gov/buildings/info/documents/pdfs/roadmap_lowres.pdf
Energy Future Coalition	Challenge and Opportunity: Charting a New Energy Future	This report provides recommendations and discussion of what is needed to address today's energy challenges.	http://www.energyfuturecoalition.org/pubs/EFCReport.pdf
EPA Combined Heat and Power Partnership	Funding Database	This Web site lists a number of state and federal incentives for combined heat and power projects and for projects using biomass/biogas.	http://www.epa.gov/chp/funding/funding.html
National Energy Technology Laboratory, 2007	A Vision for the Modern Grid	This document expands on the vision for a modern grid that will "revolutionize the electric system by integrating 21st century technology to achieve seamless generation, delivery, and end-use that benefits the nation."	http://www.netl.doe.gov/moderngrid/docs/A%20Vision%20for%20the%20Modern%20Grid_Final_v1_0.pdf

Documents That Discuss a Vision for Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
National Petroleum Council, 2007	Facing the Hard Truths About Energy	This draft report provides a comprehensive view to 2030 of global oil and natural gas.	http://downloads.connectlive.com/events/npc071807/pdf-downloads/Facing_Hard_Truths-Report.pdf
McKinsey Global Institute, 2007	Curbing Global Energy Demand Growth: The Energy Productivity Opportunity	This paper is a global study on different sectors of the economy: buildings, transportation, and industries. It details how implementing certain policies and technology developments can help reduce forecasted energy use.	http://www.mckinsey.com/mgi/publications/Curbing_Global_Energy/index.asp
North American Electric Reliability Council, 2006	2006 Long-Term Reliability Assessment	This report includes an assessment of the reliability of the bulk power systems in North America, as well as key findings and actions needed.	ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf
PJM, 2007	Bringing the Smart Grid Home	This piece provides a vision of how the U.S. electrical infrastructure will look. The concept of a smart grid is examined and its benefits are identified.	http://www2.pjm.com/documents/downloads/strategic-responses/letters/smartgrid.pdf

Documents With More Information on Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
Appliance Standards Awareness Project		This Web site provides information and resources on federal and state appliance standards.	http://www.standardsasap.org
Building Codes Assistance Project		This nonprofit organization is dedicated to helping states adopt and implement up-to-date building energy codes.	http://www.bcap-energy.org

Documents With More Information on Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
Bonneville Power Administration	Industrial Audit Guidebook	This is a guidebook for performing walk-through energy audits of industrial facilities. It highlights key measures for industrial energy savings.	http://www.bpa.gov/energy/n/projects/industrial/pdf/audit_guide.pdf
Chris King and Dan Delurey	Twins, Siblings, or Cousins	Discusses the effect of demand response programs on total energy consumption based on a survey of over 100 demand response programs.	Published in Public Utilities Fortnightly in March 2005
ERG and Energy and Environmental Analysis (EPA)	Output-Based Regulations: A Handbook for Air Regulators	EPA designed this handbook to help air regulators understand and then establish output based regulations. The report details the attributes of output-base regulations, which reward energy efficient projects by allocating allowances or issuing standards based on the productive output of the process instead of how much fuel is used. Output-based regulation design issues are also discussed.	http://www.epa.gov/cleanrgy/pdf/output_rpt.pdf
Elliott Roseman and Sandra Hochstetter	Regional Resource Planning Makes Sense	This article gives historical background on the regional resource planning process, discusses recent developments, and provides recommendations for how regional resource planning should be conducted.	http://www.energypulse.net/centers/article/article_display.cfm?a_id=1416
Gridwise at PNNL and Gridwise Architecture Council	Information on modernizing the power grid	This Web site provides information on how to update/modernize the power grid. It offers a number of resources on how to transform the grid, including the Gridwise Architecture Council's interoperability checklist (<http://www.gridwiseac.org/pdfs/gwac_decisionmakerchecklist.pdf>)	http://gridwise.pnl.gov/technologies http://www.gridwiseac.org
Michael R. Muller and Kyriaki Papadaratsakis (Industrial Assessment Center at Rutgers University), 2003	Self-Assessment Workbook for Small Manufacturers	This workbook provides information on key measures for industrial energy savings.	http://www.iac.rutgers.edu/database/technicaldocs/IAC_Manuals/selfassessment.pdf

Documents With More Information on Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
Innovest Strategic Value Advisors, 2003	Energy Management and Investor Returns: The Real Estate Sector	This paper examines energy efficiency and energy management performance in the real estate sector. It finds that companies that used energy-efficient technologies and other highly efficient products achieved the best stock and financial performance over a 2-year period.	http://www.energystar.gov/ia/business/guidelines/assess_value/reit.pdf
La Capra Associates, GDS Associates, and Sustainable Energy Advantage (North Carolina Utilities Commission), 2006	Analysis of a Renewable Portfolio Standard for the State of North Carolina	This report identifies the potential for renewable generation in North Carolina and helps identify achievable targets for a statewide renewable portfolio standard.	http://www.lacapra.com/downloads/NC_RPS_Report.pdf
Martin Kushler, Dan York, and Patti Witte (ACEEE), 2005	Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest	The Midwest has a significant number of industries that rely on natural gas and many Midwestern homes are heated by natural gas–fueled space heaters. Due to this large reliance on natural gas, the Midwest needs other fuels/technologies to meet its energy needs. This report examines the potential for energy efficiency as a way to curb the Midwest's dependence on natural gas.	http://www.aceee.org/pubs/u051.htm
Massachusetts Technology Collaborative	Decoupling of Utility Rates	This Web site contains a number of reports and other information related to decoupling of utility rates.	http://www.mtpc.org/dg/decoupling.htm
National Action Plan for Energy Efficiency, 2006	National Action Plan for Energy Efficiency	The Action Plan is a strategy developed by a diverse group of stakeholders to realize energy savings and environmental benefits through energy efficiency-related policies and other measures.	http://www.epa.gov/cleanenergy/actionplan/eeactionplan.htm
NYSERDA, 2007	New York Energy $mart^{SM} Program Evaluation and Status Report: Report to the System Benefits Charge Advisory Group	Energy $mart provides funding for energy efficiency, low-income consumers, R&D, environmental protection programs, and projects in other areas. This report describes how much money has been collected for the program, how the money is allocated, what types of projects have received funding, and identifies the benefits of the program.	http://www.nyserda.org/Energy_Information/SBC/sbcmar07coverTOC.pdf

Documents With More Information on Energy Efficiency and Related Policies, Programs, and Technologies

Author/ Source, Date	Title	Scope	Web Site
Optimal Energy (Natural Resources Defense Council and Ceres), 2007	Power to Save: An Alternative Path to Meet Electric Needs in Texas	This report presents the potential for energy efficiency and demand reductions in Texas and recommends strategies to meet this potential.	http://www.ceres.org/pub/docs/Ceres_texas_power.pdf
Plug-in Partners National Campaign and The California Cars Initiative	Information on plug-in hybrid vehicles	These two Web sites provide information on plug-in hybrids.	http://www.pluginpartners.org http://www.calcars.org

Appendix C: Energy Efficiency Benefits Analysis Assumptions



The analysis of program benefits for the Action Plan's Vision uses the Energy Efficiency Benefits Calculator, a tool that demonstrates the benefits to customers, utilities, and society of implementing energy efficiency programs. The Calculator was developed for the Leadership Group and is one of the resources available to aid users in educating stakeholders on the benefits of energy efficiency programs.

For this analysis, the Calculator was used to estimate the benefits of displacing more than 50 percent of load growth through 2025, or 20 percent of electricity consumption and 10 percent of gas consumption in 20 years. These savings were assumed to be achieved by broad adoption of a range of conventional energy efficiency programs. The estimates are based on assumptions of average program spending levels by utilities or other program administrators, with conservatively high numbers for the cost of energy efficiency programs. The economic and environmental savings estimate are extrapolations of the results from existing utility and state programs to a national scope. Emission savings are based on a marginal generation factor that is double that of the annual average.

The key assumptions are summarized in Figure C-1. Total consumption, load growth, peak demand, and retail rate assumptions are based on current data as tabulated by the Energy Information Administration (EIA) or as projected in the EIA Annual Energy Outlook 2007.

The levelized program cost of $35.00/MWh for electricity and $3.00/MMBtu for gas is assumed. (Energy efficiency program costs are based on assumptions of average program spending levels by utilities and other program administrators, as well as program participates. For electric programs, the analysis administrator costs are assumed at $20.00/MWh and $1.50/MMBtu. Participant costs are assumed at $15.00/MWh and $1.50/MMBu. Many of today's programs deliver energy savings for less than these assumed costs.)

Figure C-1. Assumptions and Inputs

Electric

- Annual consumption 2008: 3,992,000 GWh
- Peak load 2008: 971.926 MW
- Annual growth in consumption: 1.6%/year
- Annual revenue (customer bills) 2008: $351,129 million
- Efficiency program cost: $35.00/MWh
- Power plant capital cost: $1,000/kW
- Average CO_2 emission factor: 0.52 tonne/MWh
- Annual cost escalation: 2%/year

Natural Gas

- Annual consumption 2008: 22,497 Tcf
- Annual growth in consumption: 0.7%/year
- Annual revenue (customer bills) 2008: $190,726 million
- Efficiency program cost: $3.00/MMBtu
- Average CO_2 emission factor: 0.053 tonne/MMBtu
- Annual cost escalation: 2%/year

Other

- Discount rate for net present value: 5%
- Energy efficiency measure life: 15 years

Appendix D: Initial Strawman Approach for Measuring Progress



Appendix D provides an explanation of an initial approach for how progress toward the vision goals can be measured, as presented in Figures 2-1 and 2-2. An initial summary of existing state policies and actions that can assist in achieving the Vision goals has been developed and is described below. This appendix describes how the information was collected at the state and regional level, as well as describing an initial approach for determining if a state has completed a step in whole or in part. This initial summary approach will be reviewed and refined by the Action Plan Leadership Group in 2008.

Collection of Information

As part of the Action Plan's Regional Implementation Meetings, the status of 40 policy and program options to promote cost-effective energy efficiency was collected at the state level and grouped into five regions: West, Mid-Atlantic, New England, Midwest, and Southeast. This detailed information has been used to develop an initial summary approach as of 2006/2007 for the ten implementation goals and the 28 policies or program steps presented in Figures 2-1 and 2-2. In some cases, this information was supplemented with additional sources as noted in the specific program step. Further, this information was sent to state organizations for further comment.

Determining the Status of a Policy

Figures 2-1 and 2-2 summarize the status of a state-level policy or program based on it being considered to be "complete" or "partial/some elements of policy in place." These two categories have been developed from more detailed information that reflects, for a given policy at the state level, a "Y" for complete, a "P" for action is pending/possible, and an "S" for some elements of policy in place. If information was not readily available at the state level it is not included. If additional information on these policies is available based on a review of the regional summary tables, please send it to Katrina Pielli at pielli.katrina@epa.gov and it will be included as the information is updated in the future.

A more detailed explanation of the assessment for each of the implementation goals and the key policies or program steps in Figures 2-1 and 2-2 is provided below.

Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource

1. **Process in place, such as a state and/or regional collaborative, to pursue energy efficiency as a high-priority resource.** A state where stakeholders were involved in an advisory or collaborative role with program administrators, while developing energy resource plans and/or energy efficiency program plans or determining the best use of efficiency or sustainable energy funds, was considered as having "completed" this step. The sources for this information included interviews with regulators and program administrators, as well as online materials such as utility commission orders and rules. The totals in Figures 2-1 and 2-2 represent those that have been positively confirmed. There is no "partially complete" for this step.

2. **Policy established to recognize energy efficiency as high-priority resource.** A state was considered to have "completely" established energy efficiency as a high-priority resource, equivalent or superior to supply resources, if there was a clearly established policy to that effect (such as an integrated resource planning objective of acquiring all cost-effective energy efficiency). A state was considered to have "partially completed" this step if it was found to have a "Y," "P," or "S" for four

out of the following seven possible policies that states are pursing in this area:

- Energy efficiency is integrated into an active integrated resource planning, portfolio management, or other planning process.
- Energy efficiency is procured as a resource for default service/standard offer customers.
- Energy efficiency is an alternative to transmission based on a long-term transparent integrated resource planning or transmission system plan.
- Energy efficiency is a biddable commodity.
- State implementation plans include energy efficiency set-asides.
- Energy efficiency commitment is in statute.
- Energy efficiency can be used to fulfill requirements of a renewable portfolio standard or similar standard.

3. **Potential identified for cost-effective, attainable energy efficiency over the long term.** A state was considered to have "completely" established the potential for cost-effective energy efficiency through a potential study, if there was a recent, comprehensive study available for attainable energy efficiency. A state was considered to have "partially completed" this step if, for example, it had announced plans for a study but not yet completed it.

4. **Energy efficiency savings goals established consistent with cost-effective potential.** A state was considered to have "completed" this step if it had established the potential for cost-effective energy efficiency through a potential study, and also established at least one of the following:
   - Funding requirements for all long-term, cost-effective energy efficiency.
   - Quantitative MW and MWh savings goals established and producing incremental investment.

   If a state had completed one or even both of the above items, but had not established the potential for cost-effective energy efficiency by completing a potential study, then that state was considered to have "partially completed" this step.

5. **Energy efficiency savings goals integrated into state energy resource plan, with provisions for regular updates.** A state was considered to have "completed" this step if both of the following have been accomplished:
   - Energy efficiency was integrated into an active integrated resource planning, portfolio management, or other resource planning process.
   - Resource plans were regularly updated.

   A state was considered to have "partially completed" this step if it had completed only one of the above items.

6. **Energy efficiency savings goals integrated into a regional energy resource plan.** Progress will be measured for this step in the future as regional resource planning efforts evolve across the country.

Goal Two: Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources

7. **Utility throughput incentive is addressed and disincentives are removed.** A state was considered to have "completed" this step if it had addressed the utility throughput incentive and removed disincentives, such as through decoupling or lost revenue recovery. A state was considered to have "partially completed" this step if it had addressed the throughout incentive and removed disincentives for one or more utilities, but not for all utilities. If a state had an open docket on these issues but had not yet issued a final decision, it was not considered to have "partially completed" this step.

8. **Utility incentives for energy efficiency savings reviewed and established as necessary.** An

approach for measuring progress on this step is currently being developed.

9. **Timely cost recovery in place.** Progress on this policy is not currently being measured, but it is hoped that in each state's process of exploring additional energy efficiency, the timeliness of program cost recovery will be addressed.

Goal Three: Establishing Cost-Effectiveness Tests

10. **Cost-effectiveness tests adopted which reflect the long-term resource value of energy efficiency.** For the purposes of initial policy tracking, a state was considered to have "completed" this step if it included a testing method such as the total resource cost or societal cost test to evaluate energy efficiency programs. A state was considered to have "partially completed" this step if, for example, these testing methods were allowed to be used but had not been to date, or if a docket was open that was looking at cost-benefit evaluation.

Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms

11. **Robust, transparent EM&V procedures established.** A state was considered to have "completed" this step if it had a robust EM&V process in place. A state was considered to have "partially completed" this step if, for example utilities were required to develop a measurement and verification process by commission order but this action was pending, or if a docket was open that was looking at EM&V procedures.

Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms

12. **Administrator(s) for energy efficiency programs clearly established.** A state was considered to have "completed" this step if the energy efficiency delivery structure had been established. A state was considered to have "partially completed" this step if, for example, a docket was open that was looking at which entity would be the energy efficiency program administrator.

13. **Stable (multi-year) and sufficient funding in place consistent with energy efficiency goals.** A state was considered to have "completed" this step if funding requirements for all long-term, cost-effective energy efficiency had been established. If a state had completed three of the following five items, it was considered to have "partially completed" this step:

    - Cost recovery process exists.
    - Funding is for multi-year periods.
    - A base energy efficiency spending level exists, with opportunity to justify higher level.
    - Percentage of net (retail) utility revenue presently used for energy efficiency [no unit = %; m/k = mils/kWh].
    - Funds from carbon trading program support energy efficiency.

14. **Programs established to deliver energy efficiency to key customer classes and meet energy efficiency goals.** A state was considered to have "completed" this step if it had established energy efficiency programs that reach all customer classes. A state was considered to have "partially completed" this step if, for example, there was an open docket that was exploring energy efficiency programs.

15. **Strong public education programs on energy efficiency in place.** An approach for measuring progress on this step is currently being developed.

16. **Energy efficiency program administrator engaged in developing and sharing program best practices at the regional and/or national level.** A state was considered to have "completed" this step if over two-thirds of its energy efficiency budget was administered by entities that belong to the Consortium for Energy Efficiency, or that belong to or serve on the board of a regional energy efficiency market transformation organization or a regional organization dedicated to the promotion of energy efficiency.

Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices

17. **State policies require routine review and updating of building codes.** A state was considered to have "completed" this step if it had building energy codes in place and these codes were regularly updated. A state was considered to have "partially completed" this step if it had building energy codes in place but they were not regularly updated.

18. **Building codes effectively enforced.** States do not regularly conduct evaluations on code enforcement, so this information is not available. The few evaluations done to date are dated and assess the enforcement landscape very differently. Few states have plans to conduct future evaluations, given the cost of conducting these studies versus the need to use the codes funding for education and training.

19. **State appliance standards in place.** A state was considered to have "completed" this step if it has appliance and equipment efficiency standards in place that are regularly updated.

20. **Strong state and local government lead-by-example programs in place.** In The State Energy Efficiency Scorecard for 2006 (Eldridge et al., 2007), states are ranked in terms of their enactment of lead-by-example programs. The ranking categories are energy efficiency performance, new and existing state building targets, energy-efficiency produce procurement, and R&D. A state was considered to have "completed" this step if it received 2 or more points. A state was considered to have "partially completed" this step if received below 2 points but above 0 points.

Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency

21. **Rates examined and modified considering impact on customer incentives to pursue energy efficiency.** A state was considered to have "completed" this step if it had considered the impact on energy efficiency when designing retail rates. If a state had not considered that impact but had completed two of the three following items, it was considered to have "partially completed" this step:

    - Declining block rates and fixed variable rate designs have been eliminated.
    - Time sensitive rates in place.
    - Usage sensitive rates in place.

22. **Mechanisms in place to reduce consumer disincentives for energy efficiency (e.g., including financing mechanisms).** A state was considered to have "completed" this step if it had mechanisms in place such as on-bill financing and benefit sharing to encourage energy efficiency. A state was considered to have "partially completed" this step if the commission had requested that utilities submit proposals for mechanisms to reduce consumer disincentives, such as on-bill financing, or if a utility had submitted a proposal but the commission had not yet issued an order.

Goal Eight: Establishing State of the Art Billing Systems

23. **Consistent information to customers on energy use, costs of energy use, and options for reducing costs.** Progress on this policy is not currently measured. It is hoped that, in coming years and with further advanced metering infrastructure (AMI) roll-out and increased efforts to benchmark building energy use, progress will be able to be measured.

Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems

24. **Investments in advanced metering, smart grid infrastructure, data analysis, and two-way communication to enhance energy efficiency.** A state was considered to have "completed" this step if it had utilities that had contracted for AMI. A state was considered to have "partially completed" this step if it had utilities that were running AMI pilots, had AMI deployment planned, or

were planning a deployment. Some "partial" states reflect investments in smart grid infrastructure, data analysis and two-way communication. These states were listed as partial if, for example, not all utilities in the state had made investments, if investments were not yet installed, or if only some of the programs had been invested in. Three sources were used for this step: the regional summary tables tracking for AMI deployments; Appendix F of FERC, 2007; and discussion with outside parties, including experts at <http://www.SmartGridNews.com> and GridWise Alliance.

25. **Coordinated energy efficiency and demand response programs established by customer class to target energy efficiency for enhanced value to customers.** A state was considered to have "completed" this step if it had coordinated energy efficiency and demand response programs established by customer class. Discussions with outside parties, including experts at Lawrence Berkeley National Laboratory, were used to measure progress.

26. **Programs established to use trained and certified professionals as part of energy efficiency program delivery.** An approach for measuring progress on this step is currently being developed.

Goal Ten: Implementing Advanced Technologies

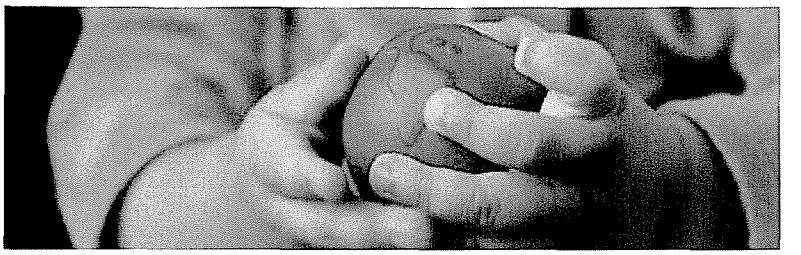
27. **Policies in place to remove barriers to clean, efficient distributed generation.** Progress was measured on policies associated with interconnection rules; reviewing clean, efficient distributed generation as part of the planning process and incorporating it where effective; and standby rates. For states with statewide policies on standby rates for distributed generation, the two largest utilities (based on EIA data) were also reviewed to see if the policies were being implemented in a way that valued the costs and benefits of distributed generation. If there was no state policy, the two largest utilities were reviewed to determine if their rates valued the costs and benefits of distributed generation.

    A state that had completed two of the three following items was considered to have "completed" the step below, and a state that had completed one of the items was considered to have "partially completed" it:

    - A statewide interconnection policy is in place.
    - As part of the resource planning process, clean, efficient distributed generation is reviewed and incorporated where effective.
    - An effective state standby rate policy is in place, or the two largest utilities have implemented rates that "value the costs and benefits of distributed generation."

28. **Timelines developed for the integration of advanced technologies.** Progress on this policy is not currently measured. It is hoped that, in coming years and with the maturity of energy efficiency technology efforts, progress will be able to be measured.

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Aligning Utility Incentives with Investment in Energy Efficiency

A RESOURCE OF THE NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY

NOVEMBER 2007

About This Document

This report on *Aligning Utility Incentives with Investment in Energy Efficiency* is provided to assist gas and electric utilities, utility regulators, and others in the implementation of the recommendations of the National Action Plan for Energy Efficiency (Action Plan) and the pursuit of its longer-term goals.

The Report describes the financial effects on a utility of its spending on energy efficiency programs, how those effects could constitute barriers to more aggressive and sustained utility investment in energy efficiency, and how adoption of various policy mechanisms can reduce or eliminate these barriers. The Report also provides a number of examples of such mechanisms drawn from the experience of utilities and states.

The primary intended audiences for this paper are utilities, state policy-makers, and energy efficiency advocates interested in specific options for addressing the financial barriers to utility investment in energy efficiency.



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