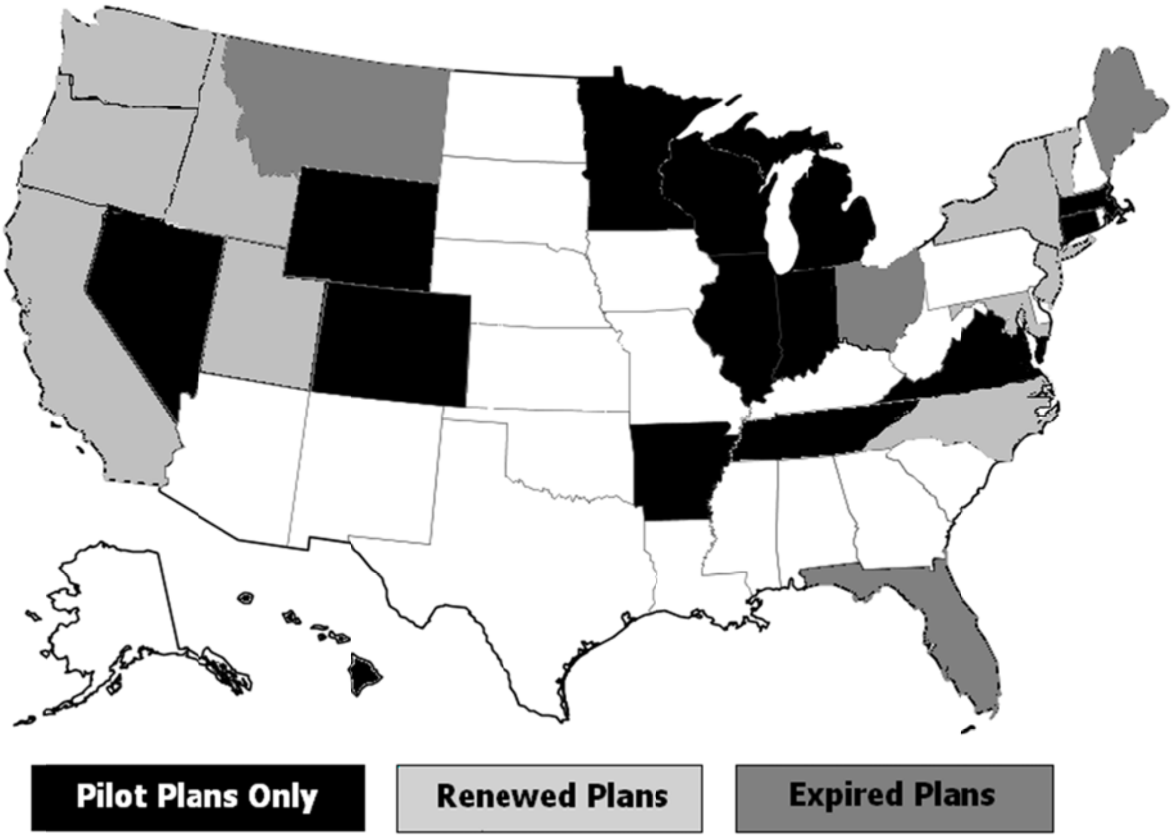
**Figure 1: U.S. Decoupling Precedents by State:**
**True up Plans**




The Commission's rationale for approving the decoupling true up plans for gas distributors placed heavy emphasis on the need to remove utility disincentives for conservation and to rectify the destabilization of earnings that had resulted from the combination of supply uncertainty and experimental rate designs.

Decoupling true up plans have been used by California's larger gas utilities in most years since their inception. These utilities have DSM programs, and these programs rank at or near the top of most surveys. Inverted block rates have continued, but were recently modified pursuant to state legislation.

Decoupling true up plans called Electric Revenue Adjustment Mechanisms ("ERAMs") were by 1982 approved for all three major California electric utilities. The appeal of decoupling true up plans in California electric utility regulation came from several sources. Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices. The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility." [40] A California Energy Commission was established to supplement PUC actions to promote conservation.

Electric utilities had experimental rate designs that promoted conservation but increased earnings risk in an environment that included risk from other sources. The CPUC was one of the few in the U.S. that required multiyear rate plans. This raised concern about financial attrition between rate cases. Companies were building nuclear power plants, and the CPUC would not allow the inclusion of the value of construction work in progress in rate base. In addition to its impact on overall risk, this circumstance increased the likelihood that the risk from conservation programs and inverted block rates would become embedded in the cost of financing the investments.

Despite a generally positive experience, the use of ERAMs fell off in the mid 1990s due, in part, to complications posed by the statutory rate freeze that accompanied retail competition. There was also some thought that DSM might be provided in the future by independent marketers. The return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk in the midst of the California power crisis.[41] All four of these utilities have subsequently returned to decoupling true up plans and operate under such plans today.

### Other Early Experience

True up plans were adopted to regulate several electric utilities in New York and the largest electric utilities in Maine (Central Maine Power) and Washington state [Puget Sound Power & Light (a/k/a "Puget Power")] in the early 1990s.[42] Experiments were also conducted in the nineties by an electric utility in Florida (Florida Power) and by the largest electric utilities in Montana and Oregon.

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[40] See, for example, CPUC D. 85559 (March 1976) p. 489.

[41] The California legislature mandated a return to decoupling in April 2001. See California Public Utilities SEC.10. Section 739.10 as amended by Assembly Bill X1 29 (Kehoe). It provides that "The Commission shall ensure that errors in estimates of demand elasticity or sales not result in material under or overcollections of the electrical corporations."

[42] The early innovators included Orange & Rockland Utilities, Niagara Mohawk Power, Consolidated Edison, Puget Power, & Central Maine Power.

Kushler, York, and Witte discuss the impact of the decoupling mechanism for Puget Power in Washington.[43] They state that "implementation of this decoupling mechanism played a critical part in changing the role of energy efficiency and conservation programs within Puget Sound Energy. In the first two years there were dramatic improvements in energy efficiency program performance." In extending the program for another three years in 1993, the Washington regulator observed that the decoupling mechanism "has achieved its primary goal – the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now a national leader in this area."[44]

Decoupling true up plans were suspended after a few years in all of these states. In New York, electric utility DSM programs were largely discontinued by the Commission at the time of the power market restructuring. In Maine and Washington, suspension was due, in whole or in part, to higher rates but the rate hikes were in each case attributable to multiple causes. For example, in Washington the decoupling mechanism was combined with a power cost adjustment mechanism. The suspension in Washington was also due to an expected power market restructuring that never transpired. Puget's DSM programs were scaled back substantially after decoupling was suspended. The complexity of the decoupling mechanisms was a stated reason for the suspension of the decoupling mechanism in Montana, which involved statistical normalization of sales volumes.[45] Florida Power did not request renewal of its residential decoupling true up plan, complaining to the commission in a 1998 letter that it was too complex, inconsistent with the company's market orientation, and provided no positive incentive to pursue DSM.

### Gas Takes the Lead

Since the end of the first wave of decoupling experimentation, decoupling true up plans have been more popular in the gas distribution industry than in the electric power industry. This reflects, in the main, the more pervasive declines in average use that gas distributors have experienced. The causes of declining average use by small-volume gas

[43] Martin Kushler *et al, op cit*, p. 40.
[44] WUTC, 11th Supplemental Order, September 1993.
[45] See, for example, Commission Order No. 5858a in Utility Division docket number 95.6.27, September 1995.

customers have been discussed in several reports.[46] Noted drivers have included high gas prices, energy efficiency gains in new construction, improved insulation of older homes, replacement of older furnaces with more efficient units, reduced winter weather severity, and utility conservation programs. The average U.S. home uses about one third less gas than it did a quarter century ago.[47]

The phenomenon of declining average use by gas customers is not confined to the United States. A Toronto consulting firm, IndEco Strategic Consulting, prepared a report for the Canadian Gas Association in 2006.[48] The report notes that declines in average use are widespread in Canada's gas distribution industry. In the residential sector, for example, average use declined by 1.1% annually on average between 1980 and 2001.

In contrast to these gas industry trends, we reported in Section 2.2.1 above that the weather normalized residential and commercial average use of electricity by a sample of utilities *grew* by more 1% or more from 1995 to 2005. Under these conditions, most electric utilities in the United States were not incentivized to propose decoupling true up plans or SFV pricing.

Outside of California, the early adopters of gas decoupling true up plans included Baltimore Gas and Electric, BC Gas (d/b/a Terasen Gas), and Northwest Natural Gas. Approvals of decoupling true up plans for gas utilities surged after 2005, spurred in part by high gas prices. Plans have now been approved for 48 North American gas utilities operating in 22 states. Several other gas utilities have had decoupling true up proposals rejected.[49] Some LDCs that operate under decoupling do not have large-scale DSM programs. Due in part to the price sensitivity of many large volume gas users in this industry, the decoupling plans of most gas distributors apply only to residential and commercial customers.

### The Electric Renaissance

A resurgence of interest in decoupling true up plans for electric utilities began in 2007. This has reflected, in large measure, the general renewal of interest in electricity

[46] See, for example, AGA, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*, September 2004.
[47] AGA May 2009, *op cit* p. 6.
[48] IndEco Strategic Consulting, "Declining Average Customer Use of Natural Gas: Issues and Options", December 2006.
[49] Examples include Nicor Gas, the Ameren utilities in Illinois, and National Grid in Rhode Island.

DSM that occurred after industry restructuring was completed and it became apparent that marketers would play a small role in supplying power to small-volume customers. There are currently twenty four plans decoupling true up plans operative in the electric power industry, involving utilities in California, Connecticut, the District of Columbia, Hawaii, Idaho, Maryland, Massachusetts, Michigan, New York, Oregon, Vermont, and Wisconsin. The eventual implementation of decoupling true up plans for all energy distributors is now required by law or commission mandate in four of the leading DSM states: California, Massachusetts, New York, and Rhode Island.

Summary

In totality, the following twenty seven states, the District of Columbia, and at least two Canadian provinces have tried decoupling true up plans for at least one gas or electric utility.

US: AR, CA, CO, CT, DC, FL, HI, ID, IL, IN, MA, MD, ME, MI, MN, MT, NC, NJ, NY, NV, OH, OR, TN, UT, VA, VT, WA, WI, WY

Canada: ONT, BC

Table 3 shows that fourteen states (Arkansas, California, Idaho, Indiana, Maryland, Massachusetts, Michigan, New Jersey, New York, North Carolina, Oregon, Vermont, Virginia, and Washington) which have experimented with decoupling true up plans have gone on to approve other such plans. Four other states (Florida, Maine, Montana, and Ohio) have not.

### 3.1.3 SFV Pricing

SFV pricing has been used on a large scale by the Federal Energy Regulatory Commission ("FERC") since the early 1990s to regulate natural gas pipelines. Eight states currently have some form of fixed variable pricing. These are indicated on the map in Figure 2. Use of fixed variable pricing in *retail* ratemaking has to date been with one exception (Mississippi) confined to the gas distribution industry. Some details of the pricing plans are reported in Table 4. In addition, several states have in recent years made noteworthy steps in the direction of SFV by redesigning energy distribution rates for small volume customers to raise customer charges and lower volumetric charges substantially.

**Figure 2: U.S. Decoupling Precedents by State: SFV Pricing**

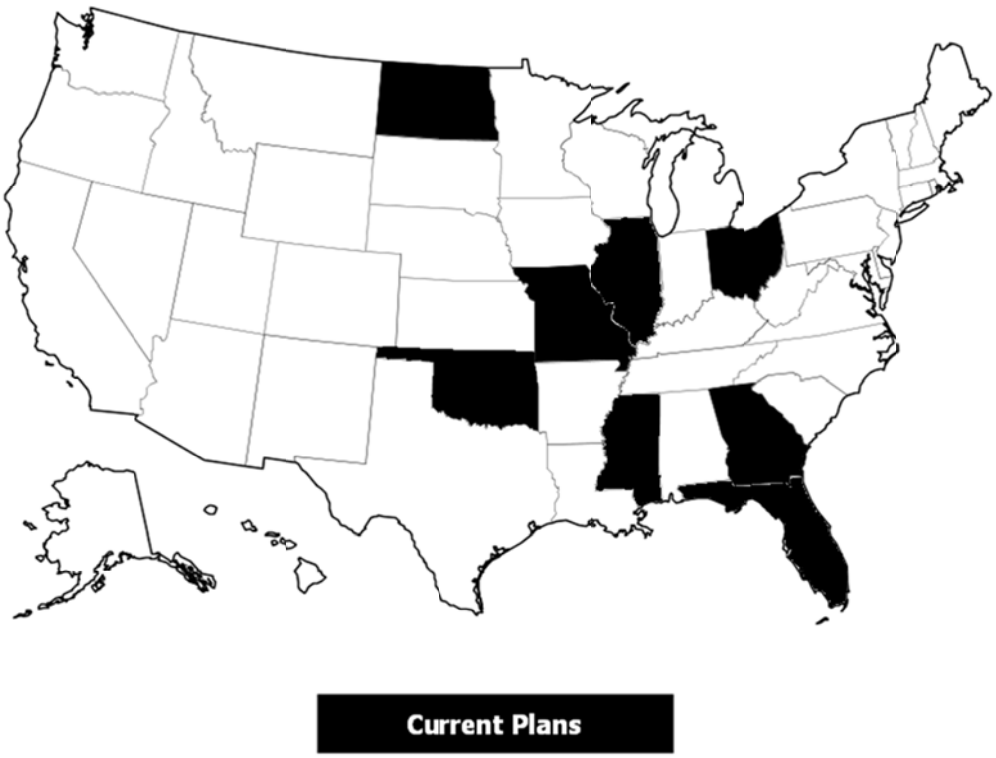


Table 4

## Retail Fixed Variable Pricing Precedents

| Jurisdiction | Company Name | Services | Years in Place | Case Reference |
|---|---|---|---|---|
| FL | Peoples Gas | Gas | 2009-open | Docket 080318-GU |
| GA | Altanta Gas Light | Gas | 1998-open | Docket No. 8390-U |
| IL | Ameren CILCO | Gas | 2008-2012 | Case 07-0588 |
| IL | Ameren CIPS | Gas | 2008-2012 | Case 07-0589 |
| IL | Ameren IP | Gas | 2008-2012 | Case 07-0590 |
| IL | Nicor Gas | Gas | 2009-open | Docket No. 08-0363 |
| MO | Atmos Energy | Gas | 2007-2010 | Case GR-2006-0387 |
| MO | Atmos Energy | Gas | 2010-open | Case No. GR-2010-0192 |
| MO | Empire District Gas | Gas | 2010-open | Case GR-2009-0434 |
| MO | Missouri Gas Energy | Gas | 2007-open | Case GR-2006-0422 |
| MO | Laclede Gas | Gas | 2002-open | Case GR-2002-356 |
| MS | Mississippi Power | Bundled Power Service | Occurred over period of years | No specific case |
| ND | Xcel Energy | Gas | 2005-open | Case PU-04-578 |
| OH | Duke Energy Ohio (CG&E) | Gas | 2008-open | Case 07-590-GA-ALT |
| OH | Dominion East Ohio | Gas | 2008-2010 | Case 07-830-GA-ALT |
| OH | Columbia Gas | Gas | 2008-open | Case 08-0072-GA-AIR |
| OH | Vectren Energy Delivery of Ohio | Gas | 2009-open | Case 07-1080-GA-AIR |
| OK | Oklahoma Natural Gas | Gas | 2004-open | Cause Nos. PUD 2004-00610, PUD 201000048, PUD 200900110 |

Ohio is noteworthy for having recently switched from the true up approach to decoupling to the SFV approach. The Public Utilities Commission of Ohio, in a decision approving MFV pricing for the gas services of Duke Energy Ohio, enumerated the following benefits:

> On balance, the Commission finds that the modified SFV rate design … is preferable to a decoupling rider. Both methods would address revenue and earnings stability issues in that the fixed costs of delivering gas to the home will be recovered regardless of consumption. Each would remove any disincentive by the company to promote conservation and energy efficiency. [SFV pricing] has the added benefit of producing more stable customer bills throughout all seasons because fixed costs will be recovered evenly throughout the year. In contrast, with a decoupling rider. …the rates would be less predictable since they could be adjusted each year to make up for lower-than-expected sales. [SFV pricing] also has the advantage of being easier for customers to understand. Customers will transparently see most of the costs that do not vary with usage recovered through a flat monthly fee…A decoupling rider, on the other hand, is much more complicated and harder to explain to customers…The Commission also believes that [SFV pricing] sends better price signals to consumers. [50]

In both the United States and Canada, most fixed variable rate designs feature the uniform fixed charge that ComEd proposes but in at least three cases, in Florida, Georgia, and Oklahoma they do not. In Florida, for example, the Peoples Gas System, which previously had a $10 monthly customer charge for residential service, recently established MFV pricing and divided the single residential service class into three classes with customer charges ranging from $12 for historically small volume users to $20 for historically large volume users.

### 3.1.4 LRAMs

LRAMs were used in several states (*e.g.* MA, MN, and OR) in the early 1990s but this approach to decoupling no longer predominates in the United States. Kushler, York, and Witte report in their 2006 study that

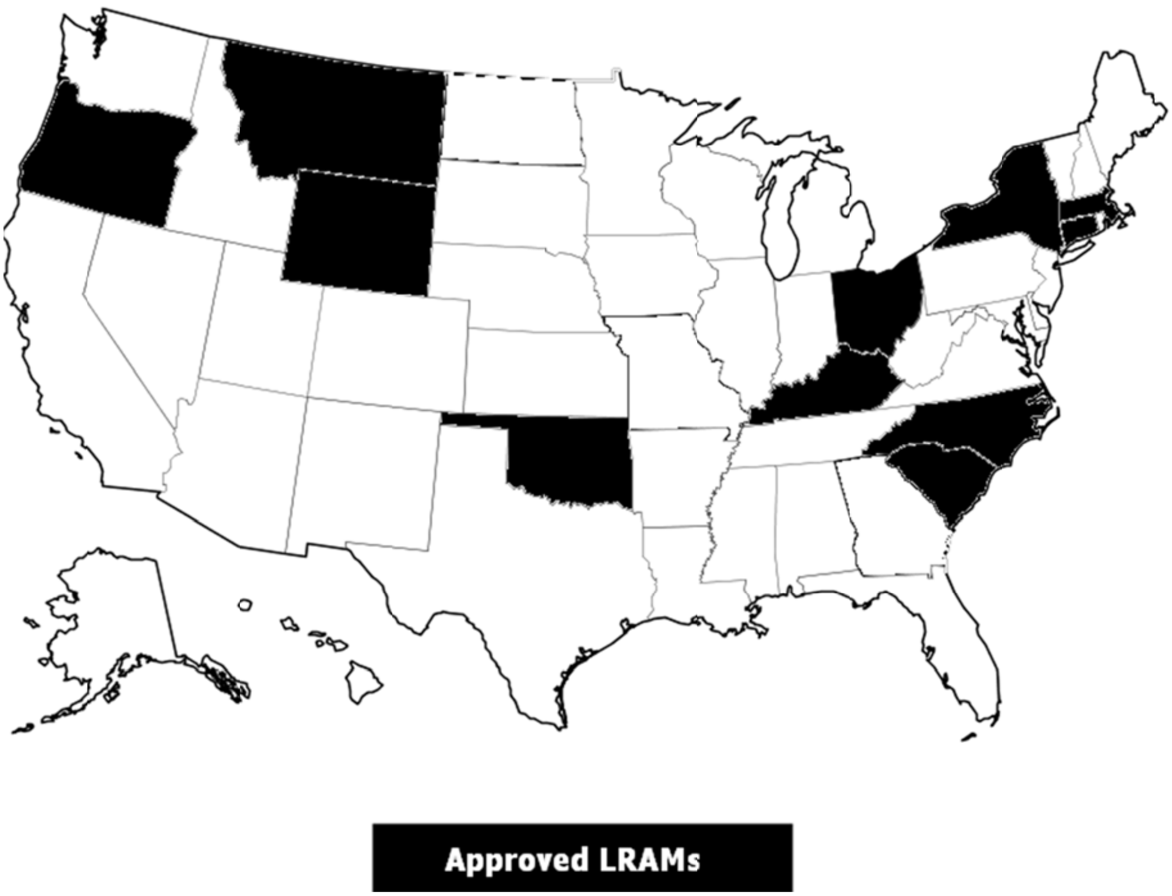
> Mechanisms to directly reimburse for specific program lost revenues have fallen from favor. Several states have had such mechanisms in the past but these practices have generally ended. 'Lost revenue" recovery remains a

[50] Public Utilities Commission of Ohio, *Opinion and Order*, 07-829-GA-AIR *et al.* pp. 23-24October 2008

concern to utilities and their regulators, but we observed that commissions appear to be addressing this through decoupling mechanisms and/or performance incentives”. [51]

**Figure 3: U.S. Decoupling Precedents by State:**

**Currently Effective LRAMs**




In Connecticut, a filing for lost margins due to *energy efficiency* requires a showing that earnings are below the allowed ROR. Lost margins can also be recovered in Connecticut for load response and LDG initiatives in a region of the state which has experienced capacity shortages. LRAMs are also part of the “Save a Watt” DSM regulatory provisions for Duke Energy in most of the states where it provides retail electric services. The AGA reports that five states used lost margin trackers for gas utilities at the end of

[51] Kushler, York, and Witte (2006) *op cit.* p. 5.

2008.[52] These states are Connecticut, Kentucky, Massachusetts, New York, and Oregon. Four of these states now also have decoupling true up plans. The states that have adopted LRAMs are indicated on the map in Figure 3.

### 3.1.5 DSM Performance Incentives

A 2010 Edison Electric Institute study found that the following eighteen states offered electric utilities incentive mechanisms for good DSM performance:

> AZ, CA, CO, CT, GA, HI, KY, MA, MI, MN, NH, NM, OH, OK, NC RI, SC, SD, TX, and WI.[53]

Decisions on such mechanisms are reported to be pending in Idaho, Indiana, Kansas, Montana, New York, and Utah. The AGA notes the existence of supplemental program incentives for gas distributors in the following eleven states in 2009:

> CA, KY, MA, MN, MO, NH, NJ, NY, NV, RI, and WI.[54]

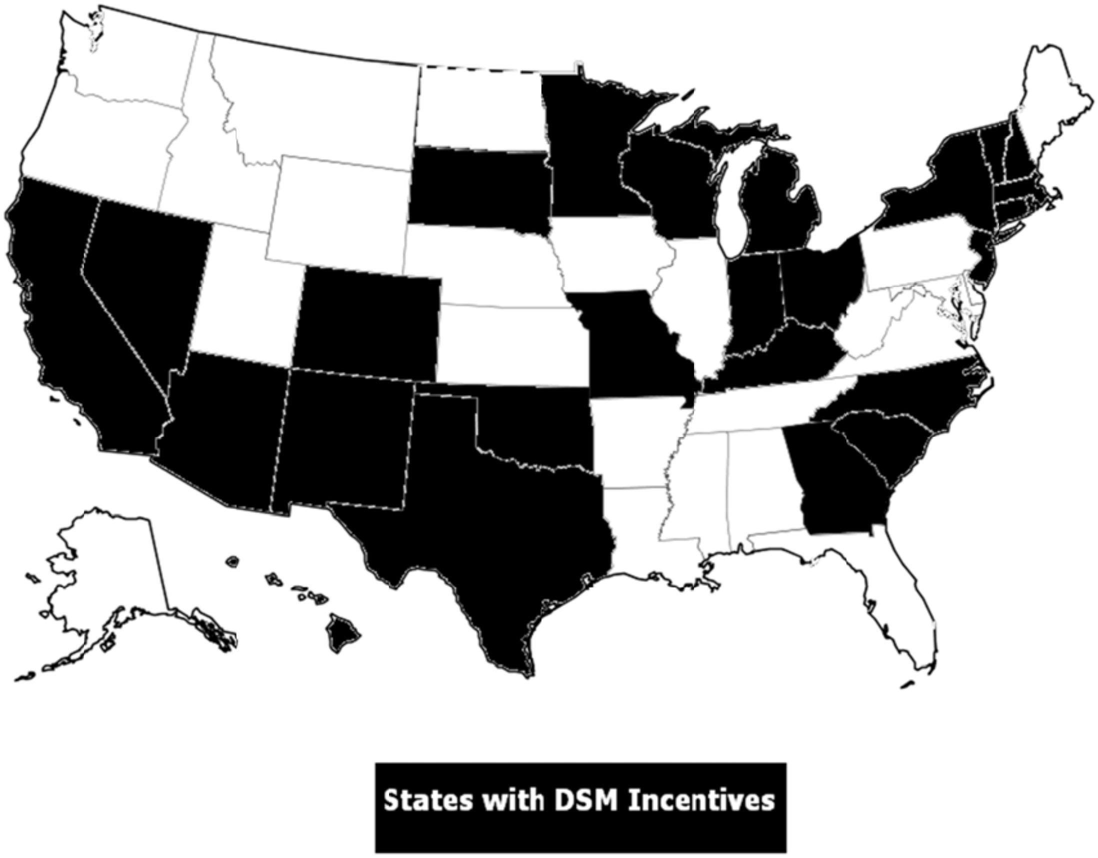
## 3.2 Performance Rankings

Before drawing some conclusions and observations about decoupling experience, we provide here some information on the approaches to decoupling in the states and Canadian provinces for which information on conservation effort is available. We examined rankings of conservation effort by two impartial sources --- the American Council for an Energy Efficient Economy and the Consortium for Energy Efficiency ("CEE") --- and also examined data from the FERC Form 1 and Form EIA 861 which we obtained from SNL.[55]

Our perusal of these sources suggests that there is no one metric that can reliability rank the scale of conservation programs. In Tables 5a and 5b we display rankings for electric and natural gas EE program scale from the CEE study. These findings are illustrated graphically in Figures 5a and 5b. The metric used in the CEE study is

[52] AGA 2009 *op cit* p. 3.
[53] Edison Electric Institute, *State Electric Energy Efficiency Regulatory Frameworks*, July 2010.
[54] AGA 2009 *op cit* p. 5.
[55] See American Council for an Energy Efficiency Economy, *The 2009 State Energy Efficiency Scorecard*, Report Number E097, October 2009 and Monica Nevius *et al*, *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts, Consortium for Energy Efficiency*, March 2010.

**Figure 4: U.S. Decoupling Precedents by State:**
**Currently Effective DSM Incentive Plans**




conservation program budgets per capita. We add dollars for ComEd conservation budgets per capita in 2010 as a point of comparison.

Table 5a

## Ratemaking Treatment of Lost Margins: Electricity

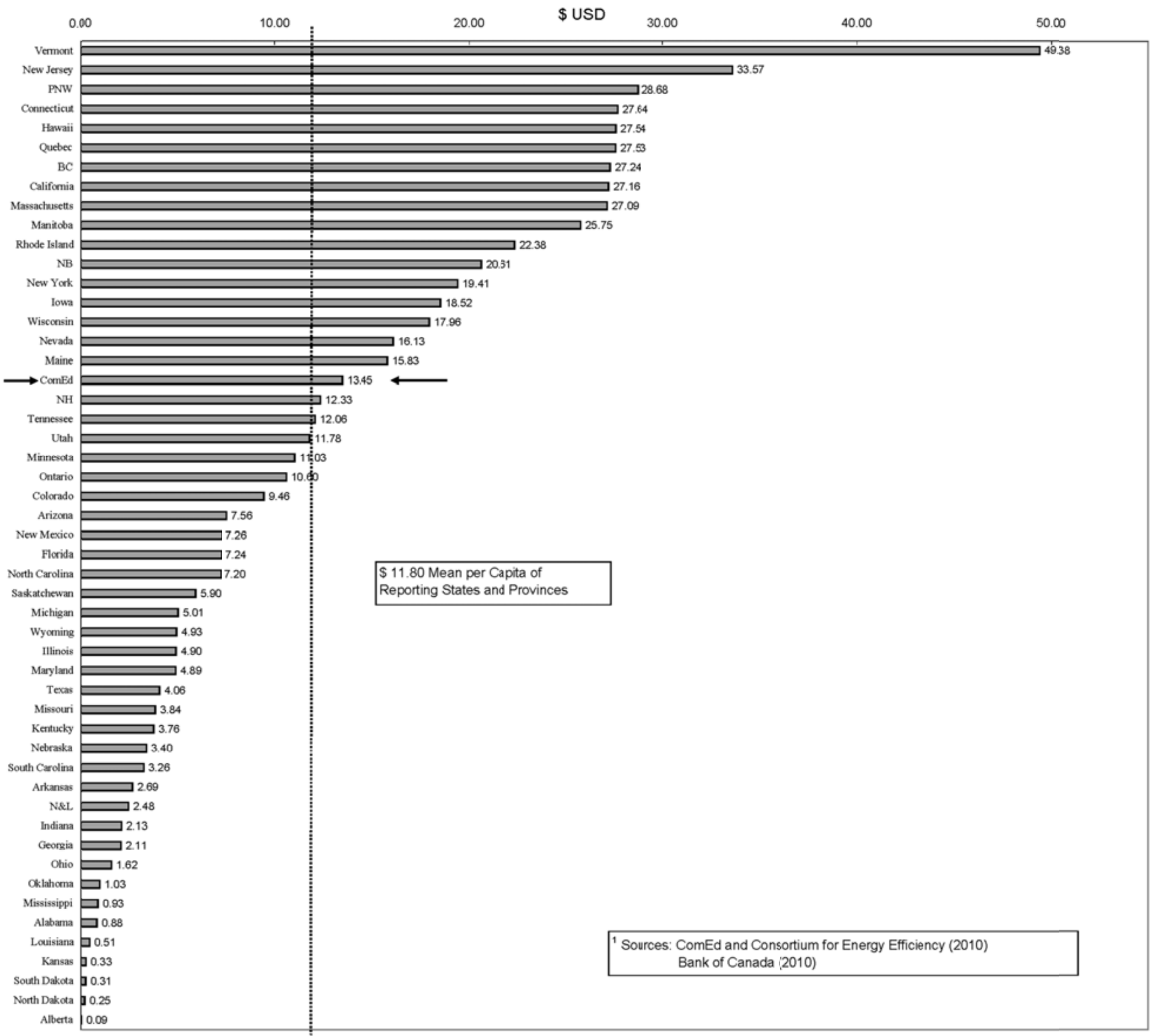
| Program | 2009 Budget/ Capita[1] ($) | Ratemaking Treatment | | | |
|---|---|---|---|---|---|
| | | Decoupling True Ups | LRAMs | SFV Pricing | DSM Performance Incentives |
| Vermont | 49.38 | Both utilities | | | For Efficiency Vermont |
| New Jersey | 33.57 | | | | |
| Pacific Northwest | 28.68 | Two utilities | One utility | | |
| Connecticut | 27.64 | One | | | All |
| Hawaii | 27.54 | Three | | | Three |
| Quebec | 27.53 | | One utility | | |
| California | 27.16 | All large utilities | | | All |
| Massachusetts | 27.09 | One | | | All |
| Rhode Island | 22.38 | | | | Only |
| New York | 19.41 | Most | | | |
| Iowa | 18.52 | | | | |
| Wisconsin | 17.96 | One | | | One |
| Nevada | 16.13 | | One utility | | |
| Maine | 15.83 | | | | |
| **ComEd[2]** | **13.45** | | | | |
| New Hampshire | 12.33 | | | | All |
| Tennessee | 12.06 | | | | |
| Utah | 11.78 | | | | |
| Minnesota | 11.03 | | | | All |
| Ontario | 10.06 | | One | | All |
| Colorado | 9.46 | | One | | One |
| Arizona | 7.56 | | | | All |
| New Mexico | 7.26 | | | | All |
| Florida | 7.24 | | | | |
| North Carolina | 7.20 | | Two utilities | | Two utilities |
| Michigan | 5.01 | Three | | | One |
| Wyoming | 4.93 | | One | | |
| Illinois | 4.90 | | | | |
| Maryland | 4.89 | Most utilities | | | |
| Texas | 4.06 | | | | All |
| Missouri | 3.84 | | | | |
| Kentucky | 3.76 | | All | | Two |
| Nebraska | 3.40 | | | | |
| South Carolina | 3.26 | | Two utilities | | Two utilities |
| Arkansas | 2.69 | | | | |
| Indiana | 2.13 | | | | |
| Georgia | 2.11 | | | | One |
| Ohio | 1.62 | | One | | One |
| Oklahoma | 1.03 | | All | | All |
| Mississippi | 0.93 | | | One | |
| Alabama | 0.88 | | | | |
| Louisiana | 0.51 | | | | |
| Kansas | 0.33 | | | | |
| South Dakota | 0.31 | | | | Three |
| North Dakota | 0.25 | | | | |

[1] Sources: ComEd and Consortium for Energy Efficiency, Inc. (2010), page 16
Bank of Canada (2010)
Data on LRAMs and performance incentives is from the Institute of Energy Efficiency *State Energy Efficiency Regulatory Framework*, June 2010.

[2] ComEd's budget value is for 2010 and includes 25% required funding by the Illinois Department of Commerce and Economic Opportunity. Population in service territory data is from ComEd's response NRDC Interrogatory 2.03 Attachment 1 in Docket 10-0467.

Figure 5a

**U.S. and Canada Electric Program Budgets per Capita**
**2009 Energy Efficiency Only**



# Table 5b

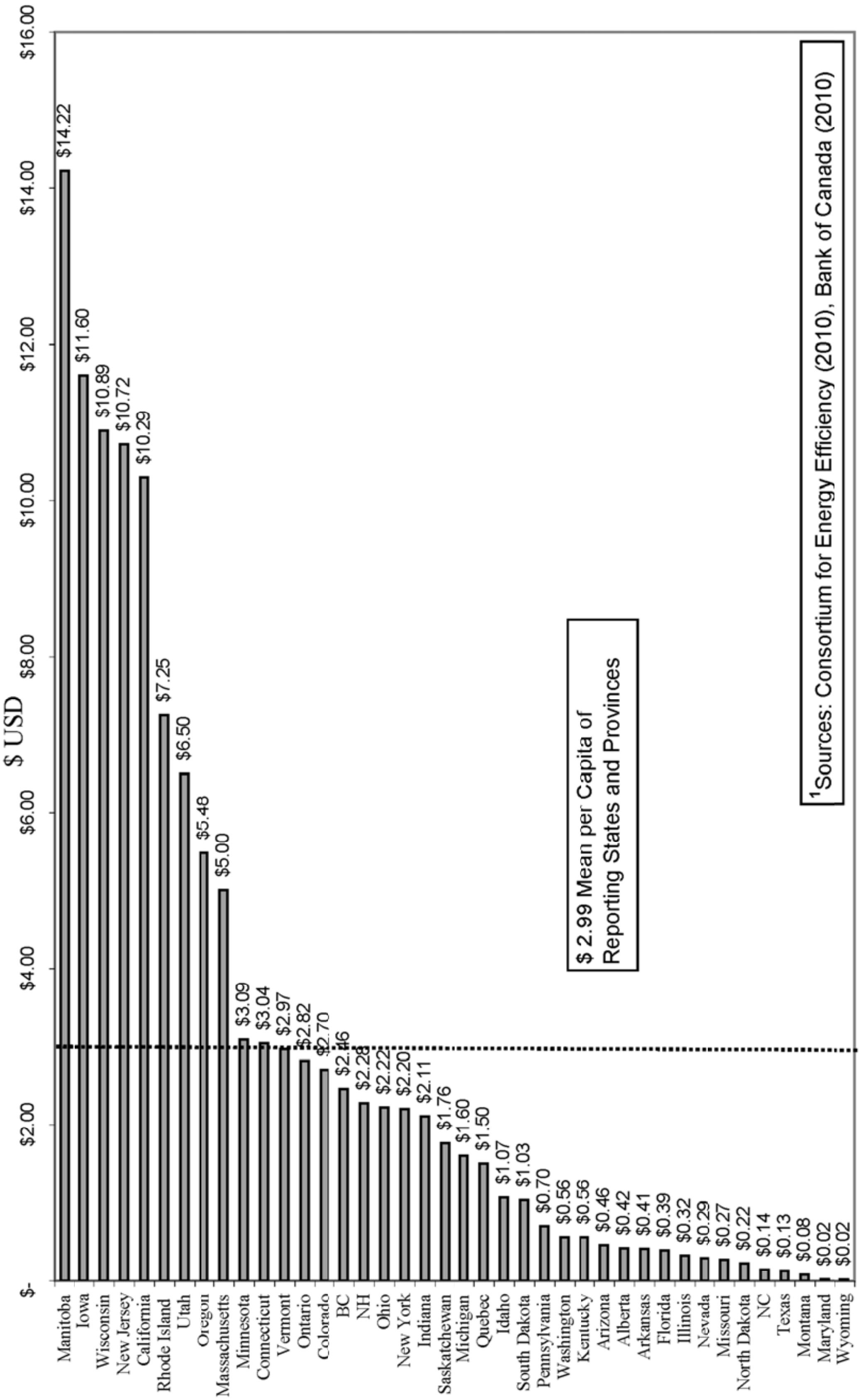
## Ratemaking Treatment of Lost Margins : Gas

| Program | $ USD/ Capita[1] | Ratemaking Treatment | | | |
|---|---|---|---|---|---|
| | | Decoupling True Ups | LRAMs | SFV Pricing | DSM Performance Incentives |
| Iowa | 11.60 | | | | |
| Wisconsin | 10.89 | One | | | One |
| New Jersey | 10.72 | Two | | | One |
| California | 10.29 | All | | | All |
| Rhode Island | 7.25 | | | | Only |
| Utah | 6.50 | Only | | | |
| Oregon | 5.48 | All large utilities | One | | |
| Massachusetts | 5.00 | Three | Four utilities | | Most utilities |
| Minnesota | 3.09 | One | | | Most utilities |
| Connecticut | 3.04 | | Two utilities | | |
| Vermont | 2.97 | Only | | | |
| Ontario | 2.82 | Both large utilities | Both large utilities | | Both large utilities |
| Colorado | 2.70 | One | | | |
| BC | 2.46 | Both utilities | | | |
| New Hampshire | 2.28 | | | | Both utilities |
| Ohio | 2.22 | | | All | |
| New York | 2.20 | All | | | One |
| Indiana | 2.11 | Most utilities | | | |
| Saskatchewan | 1.76 | | | | |
| Michigan | 1.60 | All large utilities | | | |
| Quebec | 1.50 | | | | |
| Idaho | 1.07 | | | | |
| South Dakota | 1.03 | | | | |
| Pennsylvania | 0.70 | | | | |
| Washington | 0.56 | Two | | | |
| Kentucky | 0.56 | | Most utilities | | Most |
| Arizona | 0.46 | | | | |
| Alberta | 0.42 | | | | |
| Arkansas | 0.41 | All | | | |
| Florida | 0.39 | | | One | |
| Illinois | 0.32 | Two | | Four | |
| Nevada | 0.29 | One | | | One |
| Missouri | 0.27 | | | Most | One |
| North Dakota | 0.22 | | | One | |
| North Carolina | 0.14 | All | | | |
| Texas | 0.13 | | | | |
| Montana | 0.08 | | | | |
| Maryland | 0.02 | All large utilities | | | |
| Wyoming | 0.02 | One | | | |

[1] Sources: Consortium for Energy Efficiency, Inc. (2010), page 20
Bank of Canada (2010)
Information on LRAMs given by American Gas Association *Natural Gas Rate Round Up*, May 2009.

Figure 5b

## U.S. and Canada Gas Program Budgets per Capita by State, 2009[1]



## 3.3 CONCLUSIONS AND OBSERVATIONS

Our review of decoupling experience permits us to draw some conclusions about revenue decoupling.

1. Decoupling in some form is now practiced by the great majority of American states with large-scale DSM programs.
2. True up plans are the single most popular approach to decoupling for retail gas and electric power industries. Most US jurisdictions in which there is a pronounced emphasis on DSM now have at least one utility operating under a decoupling true up plan. In jurisdictions where there is only one such plan it is often recently implemented, suggesting that true up plans are gaining favor.
3. There is no reason to think that the popularity of the true up approach is due to any superiority in providing financial attrition or removing disincentives for conventional utility DSM programs. After all, several states (*e.g.* Connecticut, Massachusetts, and Rhode Island) have only recently implemented decoupling true up plans, long *after* DSM programs reached a large scale. Moreover, decoupling true up plans have been adopted for utilities in a number of states (including Hawaii, New York, New Jersey, Oregon, Vermont, and Wisconsin) in which most DSM programs are implemented by independent agencies. Decoupling true up plans, furthermore, have been adopted for gas utilities in a number of states that are not leaders in the promotion of energy efficiency.

   These facts suggest that the popularity of decoupling true up plans is due to the other reasons that we discussed in Section 2.2. Like SFV pricing, they can compensate utilities for slow volume growth from a wide range of sources and at lower administrative cost than LRAMs. Decoupling true ups (again like SFV pricing) have the further advantage of removing disincentives for less conventional utility initiatives to encourage EE and customer-sited DG. This has been noted explicitly by several commissions. For example, the Oregon PUC stated in its order approving a new decoupling true up plan for Portland General Electric that

   > While the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the [Energy Trust of Oregon ("ETO")] running energy efficiency programs in PGE's service

> territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether it supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.[56]

**4.** Decoupling true up plans have been more widely used to date than SFV pricing. The restrictiveness of SFV pricing is doubtless a reason for this. As we have seen, SFV pricing by nature involves low volumetric rates, while decoupling true up plans make possible higher usage charges that encourage energy efficiency and peak load management, although whether the price signal sent by higher volumetric distribution charges is overstated is an open question. Many utilities operating under decoupling true up plans have introduced or maintained inverted block rates. Higher customer charges are also a concern of regulators, although we have shown that this is not an essential feature of SFV pricing although it does have benefits as well. It should also be noted that most regulators in the United States do not have jurisdiction over a large number of energy utilities. The "best in class" administrative cost of SFV pricing therefore does not carry as much weight as it might in jurisdictions with dozens of energy utilities.

5. In summary then, the popularity of decoupling true up plans may be traced primarily to their ability to provide attrition relief for slow volume growth due to a wide range of demand drivers, and to remove disincentives for a wide range of utility initiatives, at reasonable administrative cost and without high customer charges and low usage charges. In its decision approving a decoupling true up plan for BC Gas, the British Columbia Utilities Commission provided a succinct summary of its appeal.

    - The incentive for the Company to pursue short-run sales in the winter period would be eliminated, thereby eliminating the potential conflict between the demand-side pursuit of economically efficient energy services … and short-run profit maximization by the gas utility.

[56] UE 197, January 2009, p. 27

- Sales forecast risks to utility shareholders would be substantially reduced for sales to the weather sensitive residential and commercial customers---which represents the major revenue volatility of the Utility.
- Because marginal cost pricing initiatives, such as seasonal rates, would no longer be associated with increased risks for shareholders, utility management would be less reticent to support such improvements.
- The contentiousness associated with regulatory review of short-run energy demand forecasting would be largely eliminated.[57]

6. Changing circumstances can cause regulators to change their preferred decoupling approaches. Most obviously, decoupling true up plans and SFV pricing make more sense than LRAMs or DSM performance incentives once the decision is made to entrust conventional DSM programs to an independent administrator. If the utility is the administrator, it has made more sense in some states to adopt decoupling true up plans after conservation programs have reached sufficient scale that average use by small volume customers is declining.

[57] British Columbia Utilities Commission, Decision for BC Gas'1994/95 Revenue Requirements Application. August 4, 1994. p. 4-5.

# 4. REVENUE ADJUSTMENT MECHANISMS

RAMs are an important feature of the design of decoupling true up plans, although they have not always been included, as discussed earlier. Index research has been used for more than twenty years to design formulas for utility rate and revenue requirement escalation. These provide the basis for formulaic and hybrid RAMs and can also be used to appraise the popular revenue per customer approach to RAM design. We begin this section by explaining the contributions of indexing to RAM design and then discuss the established approaches to RAM design in greater detail. Details of the RAMs used in approved decoupling true up plans can be found in Table 3.

## 4.1 BASIC INDEXING CONCEPTS

Indexes are tools that make comparisons using ratios. For example, inflation in the price of gasoline in 2010 can be measured by taking the ratio of the prices in 2010 and 2009. Multiple comparisons can be summarized in an index by taking a weighted average of comparisons. The growth in a consumer price index, for instance, is a weighted average of the inflation in the prices of multiple consumer products where the shares of each product in the typical budget of consumers serve as weights.

Productivity (trend) indexes measure changes in the efficiency with which firms convert inputs to outputs. The growth trend of a productivity index is the difference between the trends in output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities \qquad [2]$$

An output quantity index for a firm or industry summarizes trends in the amount of work that is performed. An input quantity index summarizes trends in the amounts of production inputs used.

## 4.2 USE IN REVENUE CAP DESIGN

### Full Indexation

The full indexation approach to RAM design takes full advantage of the logic of economic indexes. The analysis begins by considering that the growth trend in the revenue requirement of a utility operating under cost of service regulation equals the growth trend of its corresponding cost:

$$trend\ Revenue\ Requirement = trend\ Cost. \qquad [3]$$

A basic result of index logic is that the trend in a utility's cost is the sum of the trends in appropriately specified industry input price and quantity indexes:

*trend Cost = trend Input Prices + trend Input Quantities.* [4]

Suppose, next, that we use the number of customers to measure the effect of output growth on cost. Then

*trend Cost = trend Input Prices*

– (*trend Customers - trend Input Quantities*) + *trend Customers*

= *trend Input Prices – trend Productivity + trend Customers.* [5]

The trend in cost decomposes into the trends in input price and productivity indexes and the number of customers served. In this formula, the number of customers is used as the output measure in the productivity index.

This is an important result for several reasons. One is that it demonstrates that a fully compensatory RAM should account in some fashion for inflation, productivity, and customer growth. Another is that it provides the basis for a formulaic RAM that escalates revenue for the cost impact of inflation and customer growth.

Relation [6] is one example of a full indexation formula for RAM design. An equivalent result can be obtained by escalating revenue per customer using the formula

*trend Cost/Customer = trend Input Prices – trend Productivity* [6]

and then using a utility's latest customer numbers to establish the new revenue requirement. A RAM with a design based on this formula is sometimes called a revenue per customer index.

Inflation Only RAMs

More simplified formulas based loosely on index logic are sometimes used in RAM design. For example, if customer growth is assumed to equal the productivity growth target, relation [6] simplifies to

*trend Cost = trend Input Prices.* [7]

A few approved RAMs feature inflation and productivity terms but not a customer growth allowance. An example is the CPI – 1% RAM approved in 2008 for the power distribution services of Central Vermont Public Service. Our analysis suggests that an escalation formula that accounts for inflation and productivity growth but not for customer growth will be uncompensatory in the general case.

Revenue Per Customer Freezes

Revenue per customer freezes were noted in Section 2.1.1 to be one of the most common forms of formulaic RAMs and to be used in Rider VBA of the Integrys Illinois gas utilities. Relation [5] shows that an RPC freeze provides appropriate compensation for cost growth only when a company's input price growth is similar to a reasonable target for its productivity growth. This assumption is generally unreasonable because productivity growth is typically a good bit slower than input price inflation, as we noted in Section 21.1. Our research therefore suggests that RPC freezes are uncompensatory if relied on as the sole basis for adjusting utility revenue requirements. Moskovitz and Swofford note in an early 1990s treatise that: "The RPC decoupling method is not designed to change the length of time between utility rate cases. The utility remains free to initiate a general rate case if its financial condition requires it." [58]

PEG Research has interviewed the staff of several utilities operating under RPC freezes. All of the respondents indicated that they did not expect these mechanisms to provide full attrition relief. All retained the right to file rate cases. Many utilities operating under RPC freezes have filed rate cases.

The fact that RPC freezes apply chiefly to gas distributors makes sense since these utilities are more likely to settle for an inadequate RAM in order to obtain some relief from the relatively pronounced problem of declining average use that they often face. Note also

[58] See David Moskovitz and Gary B. Swofford, "Revenue per Customer Decoupling" in Steven M. Nadel, Michael W. Reid and David R. Wolcott, eds. *Regulatory Incentives for Demand-Side Management*. Washington, D.C. and Berkeley CA, American Council for an Energy Efficient Economy, 1992.

that a number of the RPC freezes for gas utilities have been approved in states with historical test years.

### 4.3 All Forecast RAMs

All forecast RAMs were noted in Section 2.1.1 to be based solely on cost growth forecasts. Our discussion suggests that these RAMs should take account of inflation, productivity, and customer growth trends to be fully compensatory. All forecast RAMs have several advantages in accomplishing this goal. One is that they can sidestep the complex issue of input price and productivity measurement. Complexity is especially great in the measurement of capital cost. Many participants in the regulatory arena are unfamiliar with the measurement of capital price and quantity trends. Another advantage of all forecast RAMs stems from the fact that full indexation RAMs usually reflect a judgment concerning *long* run industry productivity trends. The resultant productivity targets are often unsuitable for funding the surges in maintenance expenses and/or plant additions that utilities sometimes make.

The chief downside of using all forecast RAMs is their rigidity. Inflation and other business conditions that affect utility cost do not always turn out as forecasted. The result can be windfall gains or losses for utilities and higher operating risk.

### 4.4 Hybrid RAMs

The hybrid approach to revenue cap design was noted in Section 2.1.1 to use a mix of formulaic and forecasting methods. In North America, hybrid RAMs have the following typical features.

- Budgets for non-energy O&M expenses are escalated automatically using formulas that reflect new information on cost drivers. These formulas usually involve an inflation measure and may also feature explicit adjustments for customer growth and a productivity growth target.
- Plant addition budgets for each year of the rate plan are set in advance. These budgets may have a rigid stairstep quality or be subject to adjustments for changes in construction costs. Major plant additions are sometimes subject to a separate approval process.
- The future budget for the cost of plant ownership is usually forecasted using traditional cost of service methods. This is fairly straightforward inasmuch as the

> depreciation and return on rate base that result from a set of older investments and predetermined plant additions is straightforward to calculate. The most unpredictable element, the cost of obtaining funds in capital markets, is sometimes subject to separate adjustments during the rate plans to reflect new information about the cost of capital.

This general approach to RAM design has a number of advantages. Indexing is used where it is least controversial, as in the escalation of O&M expenses. There is no need for the complex calculations needed to measure input price and productivity trends for utility plant. The treatment of capital cost is flexible enough to accommodate surges in plant additions.

### 4.5 RAM Design Precedents

Regarding the popular forms of RAM design, Table 3 shows that the RPC freeze approach was first employed by Puget Power and Central Maine Power in the early 1990s. RPC freezes are currently used by many utilities outside California. Most are gas utilities, but this approach has also recently been adopted by electric utilities in the District of Columbia, Idaho, Maryland, Michigan, and Wisconsin. The full indexation approach to RAM design is currently used by Enbridge Gas Distribution (Canada's largest gas distributor) and was previously used by Southern California Gas. Inflation only RAMs were favored a few years ago by utilities in California and have also been used in plans for several Canadian oil pipelines.

The hybrid approach was noted above to have been the most common approach to RAM design in California over the years. Revenue per customer freezes have never to our knowledge been used in California because utilities there are required to use multiyear rate plans and RPC freezes are uncompensatory in this context. Hybrid RAMs have also been used by several Canadian utilities and are currently used by the three Hawaiian Electric companies. Stairstep RAMs have been the norm over the years in New York and have also been used in Oregon. They are currently used by all four large California utilities.

Despite the popularity of RPC freezes in the gas industry, the great majority of RAMs that have been approved around the world and over time have been designed to provide automatic attrition relief for inflation as well as customer growth. All forecast and hybrid RAMs have been the principle means of providing such relief. Their popularity may be attributed to the flexibility with which they can provide relief for inflation and customer growth, under a variety of operating conditions that include capital spending surges, without complex index research.

# 5. APPLICATION TO COMED

In this final chapter of the report we apply the analysis presented in Chapter 2 to consider the best decoupling strategy for ComEd. We begin in Section 5.1 with a quick review of key considerations that may indicate the need for some form of decoupling. In Section 5.2, we examine the Illinois policy environment. We then examine the situation of ComEd in Section 5.3 and draw some policy conclusions.

## 5.1 KEY BUSINESS CONDITIONS

Our discussion in Chapter 2 suggested that revenue decoupling in some form is a sensible addition to the regulatory system to the extent that some combination of the following conditions hold.

- policymakers place a high priority on DSM promotion;
- utilities administer conventional DSM programs and/or can effectively promote DSM in other ways;
- utilities have material volumetric charges for small volume customers that jeopardize earnings but encourage conservation;
- average use of the utility system by small volume customers is declining; and
- rate cases use historical test years so that rates when implemented do not reflect the tendency of cost to rise more than billing determinants in the period between the test year and the rate year.

We turn now to a consideration of these and other relevant conditions facing ComEd.

## 5.2 ILLINOIS POLICY ENVIRONMENT

### 5.2.1 General Features of Illinois Regulation

The terms of retail services offered by ComEd are regulated by the ICC. Base rates are traditionally adjusted chiefly in general rate cases. The ICC maintains a flexible policy concerning rate case test years and recently approved new rates for the Integrys gas utilities that are based on a forward test year filing.[59] However, historical test years have been more the rule than the exception for Illinois electric utilities in recent years. ComEd, for example, has not received a rate increase based on a FTY rate case for sixteen years, since 1994. Pro forma adjustments are allowed to historical test year costs and revenues but only where changes in costs and revenues "are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable."[60]

The Commission has in the past approved a number of cost trackers, including the Rider SMP that ComEd has recently used to recover the costs of a system modernization project that included AMI. However, the Illinois Second District Court of Appeals recently overturned its decision in Docket 07-0566 to approve Rider SMP on the grounds that it violates the rule against single-issue ratemaking.[61]

### 5.2.2 State DSM Policies

DSM Goals

The state of Illinois requires investor-owned energy utilities to promote energy conservation. According to Illinois statutes, each Illinois electric utility must develop a three year plan to meet specific savings targets, subject to the constraint that if costs exceed statutory limits, energy efficiency and demand response spending is to be reduced. The targets for incremental annual energy savings goals gradually increase, rising from 0.2% for 2008 to a sizable 2.0% for 2015 and each year thereafter.[62] Utilities are also required to reduce peak demand by 0.1% each year for a 10 year period.[63] If a large utility, like ComEd, fails to meet its target after two years, it is required to pay penalties. After any three year period of non-compliance, the Illinois Power Authority would become responsible for implementing that company's energy efficiency measures.

The Commission has established collaboratives on smart grid and plug-in vehicles. The smart grid collaborative recently resulted in an extensive report which defines the method by which smart grid investments will be proposed and on what basis they should be

[59] To the best of our knowledge, the only Illinois utility to consistently use a forward test year over the past 20 years is Nicor Gas.
[60] 83 Ill.Admin Code 287.40.
[61] Appellate Court of Illinois Second District. No. 07—0566, September 2010.
[62] Each savings year begins on June 1 and ends on May 31 of the following year.
[63] 220 ILCS 5/8-103.

approved. The ICC is expecting that a final report by the plug-in collaborative will be issued in Spring 2011.

### Ratemaking Treatment of Conservation Programs

Cost riders for energy efficiency programs have been expressly approved by Illinois law which allow for an automatic adjustment clause tariff that operates outside of general rate cases. A mechanism that could be characterized as an instance of an LRAM was approved for Commonwealth Edison in 1991. The decision was appealed to the First District Appellate Court and overturned on a variety of issues. The appellate court ruled that the LRAM was illegal for a variety of reasons.[64]

Decoupling true ups plans have already been effectively instituted in Illinois for retail electric transmission revenue. It is noteworthy that retail transmission revenue requirements for residential and watt hour customers are recovered via flat volumetric charges. These charges encourage customers to invest in DSM equipment. ComEd's commodity costs are also recovered on a basis that protects ComEd from volume fluctuations.

The ICC-approved the previously mentioned pilot revenue decoupling plans for the Integrys gas utilities in 2008.[65] These plans have a four year term, focus on only the residential and commercial/general service classes, have separate baskets for each class, and allow for the recovery of certain of those costs that the Commission deemed to be fixed. True ups are made annually. The approval of revenue decoupling was followed by an appeal by the Illinois Attorney General's Office and certain other parties to the 1st District Appellate Court. A decision in that case is pending.

The ICC has recently approved MFV pricing plans for the Ameren gas utilities and Nicor Gas. In both cases, the approval of MFV was preferred to the implementation of a decoupling true up proposal. The Ameren gas utilities' MFV plan was designed to be a pilot which would last four years, affect its residential and small commercial rate classes only, and lead to monthly residential customer charges between $15 and $20. Approximately 80% of fixed costs would be allocated to the customer charge. The Attorney General

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[64] Appellate Court of Illinois First District. No. 91-3854, June 1993.
[65] Illinois Commerce Commission order in Dockets 07-0241/07-0242 Cons.

appealed the Ameren MFV plan but it was upheld by the 4th District Appellate Court.[66] No appeal was made of the Nicor MFV plan. Nicor Gas has subsequently requested the approval of a mechanism to help guarantee recovery of the remaining 20% of fixed costs through a rider that is similar to an LRAM.

## 5.3 Commonwealth Edison

### 5.3.1 Company Overview

ComEd is the largest electric utility in Illinois. In 2009 it provided electric service to 3.7 million electric customers in a service territory with more than 9 million inhabitants. This territory includes the city and most suburbs of Chicago. ComEd also serves many smaller communities and more rural areas of northern Illinois.

The electric power industry of Illinois has been restructured. ComEd now provides unbundled distribution services. Transmission services in ComEd's service territory are provided by the PJM Interconnection, a regional transmission organization, but most transmission facilities in ComEd's service territory are owned by ComEd.

ComEd procures power for most of its small-volume customers. Most power procured today is obtained by the Illinois Power Authority by competitive bid. More than half of this power is obtained from nuclear generators.

The economy of ComEd's service territory has a fairly normal mix of commercial and industrial activity. There are many auto industry suppliers in the industrial sector, including auto assembly plants. Some of these suppliers could benefit from growing demand for electric vehicles.

Demand in the service territory peaks in the summer months when prices on the bulk power market tend to be high. This increases the payoff from peak load management and AMI. The cost competitiveness of customer-sited solar resources is reduced by the northerly latitude of the service territory but increased by a continental climate that features substantial sunshine.

### 5.3.2 Conservation Programs

The Company has achieved all of the statutory requirements discussed in Section 5.2.2 to date and is on track to exceed its 2010 goals while spending less than the cost limits.

[66] Appellate Court of Illinois, Fourth District, No. 08-0895, November 2009.

ComEd has recently filed for its second three year energy efficiency plan. In its filing, ComEd has requested that since the budget remains flat for the second three year plan, that the savings target remain flat as well.[67] In its evaluation of ComEd's energy efficiency plan, the NRDC recently concluded that the savings target for the final year might be attainable with the statutory budget cap but "would be a bad outcome because it would reduce the range of customers who would participate in programs, focus excessively on savings that have short lives, and do too little to build a foundation for deeper savings in the future."[68] The size of ComEd's incremental energy efficiency savings are shown in Table 6. It can be seen that savings have been large only since 2009. ComEd recently commissioned a study which found that 14% of its demand could be eliminated economically through efficiency projects, compared to its current targets that are less than 1% per year.

It is difficult to ascertain how ComEd's electric conservation program compares to others across the nation. The results in Table 5a and Figure 5a suggest that utilities in several states and Canadian provinces had a 2009 *budget* per capita that exceeded ComEd's. States and provinces with better metrics included Vermont, New Jersey, Quebec, British Columbia, Manitoba, Connecticut, Hawaii, California, and Massachusetts. While ComEd is required to continue increasing its electric DSM levels from 2009 levels, the same can be said of some of the other leading states. Since passage of the Green Communities Act, for instance, utilities in Massachusetts are required by law to acquire all cost-effective conservation.

[67] ComEd Exhibit 1.0 in ICC Docket 10-0570.
[68] NRDC Testimony of Chris Neme, NRDC Exhibit 1.0 in ICC Docket 10-0570.

Table 6

## Incremental Savings from ComEd Energy Efficiency Programs

| Year | Residential (MWh) | Small C/I (MWH) | Large C/I (MWH) | Cost ($1,000's) |
|---|---|---|---|---|
| 1990 | | | | |
| 1991 | | | | |
| 1992 | - | - | 410 | |
| 1993 | 600 | - | - | |
| 1994 | - | - | 290 | |
| 1995 | - | 15,000 | - | |
| 1996 | - | 8,700 | - | |
| 1997 | - | - | - | |
| 1998 | 23 | 34,450 | - | $ 4,500 |
| 1999 | 23 | 19,350 | - | $ 6,000 |
| 2000 | - | 180 | - | $ 150 |
| 2001 | - | - | - | |
| 2002 | - | - | - | |
| 2003 | - | - | - | |
| 2004 | - | - | - | |
| 2005 | - | - | - | |
| 2006 | 36,105 | | | |
| 2007 | 31,330 | | | $ 1,560 |
| 2008 | 46,850 | 13,800 | 14,000 | $ 12,080 |
| 2009 | 147,150 | 93,100 | 68,800 | $ 38,479 |
| 2010 | 241,950 | 124,150 | 82,750 | $ 63,270 |

Notes:
1) Data for 1990 through 2005 from EIA-861 database
2) Data for 2006-2007 from KEMA Evaluation of CARE CFL and Low-Income Programs
3) Blank cells indicate values not available from attributed sources
4) Small C/I assumed to be Rate 6/6T class (< 1MW)
5) 2008 and 2009 values are measured results.
6) 2010 values are forecasted, with 7 months of Ex Ante MWHs
7) 2010 Small/Large C&I allocated 60/40 of total

Source: ComEd

### 5.3.3 Use per Customer Trends

Trends and the growth rates in weather normalized average sales of power to *residential* and small commercial customers of ComEd can be found in Table 7 and Figures 6a and 6b. From 1991 to 2007, residential average use averaged 1.0% annual growth. From 2007 to 2010, however, average use has fallen an average of 0.7% annually. It is forecasted to fall by 0.8% annually on average from 2011 to 2015. The results for commercial customers are broadly similar.

### 5.3.4 Recommended Decoupling Strategy

Having reviewed the situation of ComEd in some detail, it is clear that the Company is operating today under circumstances commonly addressed by some form of revenue decoupling in North America. We believe that at least one of the established forms of revenue decoupling can and should be implemented for ComEd in this proceeding. Here are some notable benefits.

- Disincentives can be removed for the wide array of initiatives ComEd can pursue to promote DSM. ComEd can potentially be encouraged to become a national leader in all of the major areas of modern DSM: demand response, energy efficiency, and load-displacement generation. Were this achieved, customer bills would be lower, the environment would be cleaner, and vendors of DSM equipment and services could make their full potential contribution to the betterment of the northern Illinois economy.
- ComEd can be compensated for declining average use without expectation of overearning.
- Rate case controversies over delivery volumes can be mitigated.
- The Commission can learn more about the pros and cons of decoupling in an application to an electric delivery utility. For example, it can take a close look at whether decoupling encourages more DSM effort, destabilizes rates unduly, or encourages overearning.

With regard to the best approach to decoupling for ComEd, we feel that each of the established approaches has advantages that the Commission should consider. SFV pricing

Table 7

# Trends in Average Deliveries to ComEd's Small Volume Customers

| | Weather Normalized Deliveries (GWh) | | Number of Customers | | Normalized Deliveries per Customer | | | |
|---|---|---|---|---|---|---|---|---|
| | Residential | Small Commercial | Residential | Small Commercial | Residential | | Small Commercial | |
| | | | | | kWh | Annual Growth Rate | kWh | Annual Growth Rate |
| 1991 | 21,067 | 22,823 | 2,945,911 | 278,280 | 7,151 | | 82,014 | |
| 1992 | 20,553 | 23,244 | 2,965,652 | 280,451 | 6,930 | -3.1% | 82,881 | 1.1% |
| 1993 | 21,013 | 23,619 | 2,993,591 | 282,601 | 7,019 | 1.3% | 83,576 | 0.8% |
| 1994 | 21,583 | 24,350 | 3,047,354 | 286,793 | 7,083 | 0.9% | 84,905 | 1.6% |
| 1995 | 22,018 | 24,965 | 3,079,381 | 288,848 | 7,150 | 1.0% | 86,430 | 1.8% |
| 1996 | 22,521 | 25,219 | 3,102,101 | 289,803 | 7,260 | 1.5% | 87,022 | 0.7% |
| 1997 | 22,603 | 26,049 | 3,123,364 | 291,143 | 7,237 | -0.3% | 89,470 | 2.8% |
| 1998 | 23,926 | 27,045 | 3,134,490 | 304,208 | 7,633 | 5.5% | 88,902 | -0.6% |
| 1999 | 23,551 | 29,160 | 3,145,712 | 309,828 | 7,487 | -1.9% | 94,117 | 5.9% |
| 2000 | 24,554 | 29,158 | 3,172,631 | 312,991 | 7,739 | 3.4% | 93,158 | -1.0% |
| 2001 | 25,340 | 29,628 | 3,224,841 | 321,161 | 7,858 | 1.5% | 92,252 | -1.0% |
| 2002 | 26,330 | 30,465 | 3,248,065 | 323,627 | 8,106 | 3.2% | 94,137 | 2.0% |
| 2003 | 26,973 | 31,127 | 3,280,007 | 327,141 | 8,223 | 1.4% | 95,148 | 1.1% |
| 2004 | 27,930 | 31,212 | 3,312,030 | 332,016 | 8,433 | 2.5% | 94,006 | -1.2% |
| 2005 | 28,624 | 32,350 | 3,344,609 | 343,827 | 8,558 | 1.5% | 94,089 | 0.1% |
| 2006 | 28,516 | 32,284 | 3,382,930 | 347,950 | 8,429 | -1.5% | 92,783 | -1.4% |
| 2007 | 28,459 | 33,508 | 3,421,075 | 358,439 | 8,319 | -1.3% | 93,483 | 0.8% |
| 2008 | 28,599 | 33,391 | 3,439,558 | 360,005 | 8,315 | 0.0% | 92,753 | -0.8% |
| 2009 | 28,202 | 32,644 | 3,425,798 | 359,337 | 8,232 | -1.0% | 90,846 | -2.1% |
| 2010 | 27,953 | 32,417 | 3,435,628 | 361,574 | 8,136 | -1.2% | 89,656 | -1.3% |
| 2011 | 28,128 | 32,542 | 3,468,001 | 364,208 | 8,111 | -0.3% | 89,350 | -0.3% |
| 2012 | 28,156 | 32,914 | 3,502,681 | 367,486 | 8,038 | -0.9% | 89,567 | 0.2% |
| 2013 | 28,002 | 32,952 | 3,535,957 | 370,426 | 7,919 | -1.5% | 88,956 | -0.7% |
| 2014 | 28,011 | 33,024 | 3,566,012 | 373,729 | 7,855 | -0.8% | 88,363 | -0.7% |
| 2015 | 28,010 | 33,083 | 3,592,757 | 376,345 | 7,796 | -0.7% | 87,905 | -0.5% |
| **Annual Average Growth Rates** | | | | | | | | |
| **1991-2007** | **1.9%** | **2.4%** | **0.9%** | **1.6%** | | **1.0%** | | **0.8%** |
| **2008-2010** | **-0.6%** | **-1.1%** | **0.1%** | **0.3%** | | **-0.7%** | | **-1.4%** |
| **2011-2015** | **0.0%** | **0.4%** | **0.9%** | **0.8%** | | **-0.8%** | | **-0.4%** |

Sources
2010 represents Com Ed's 10+2LE view
2011-2015 reflects Com Ed's preliminary 2011 budget (IPA Nov 2010 filing)

Figure 6a

## ComEd Normalized Residential Average Use Trend

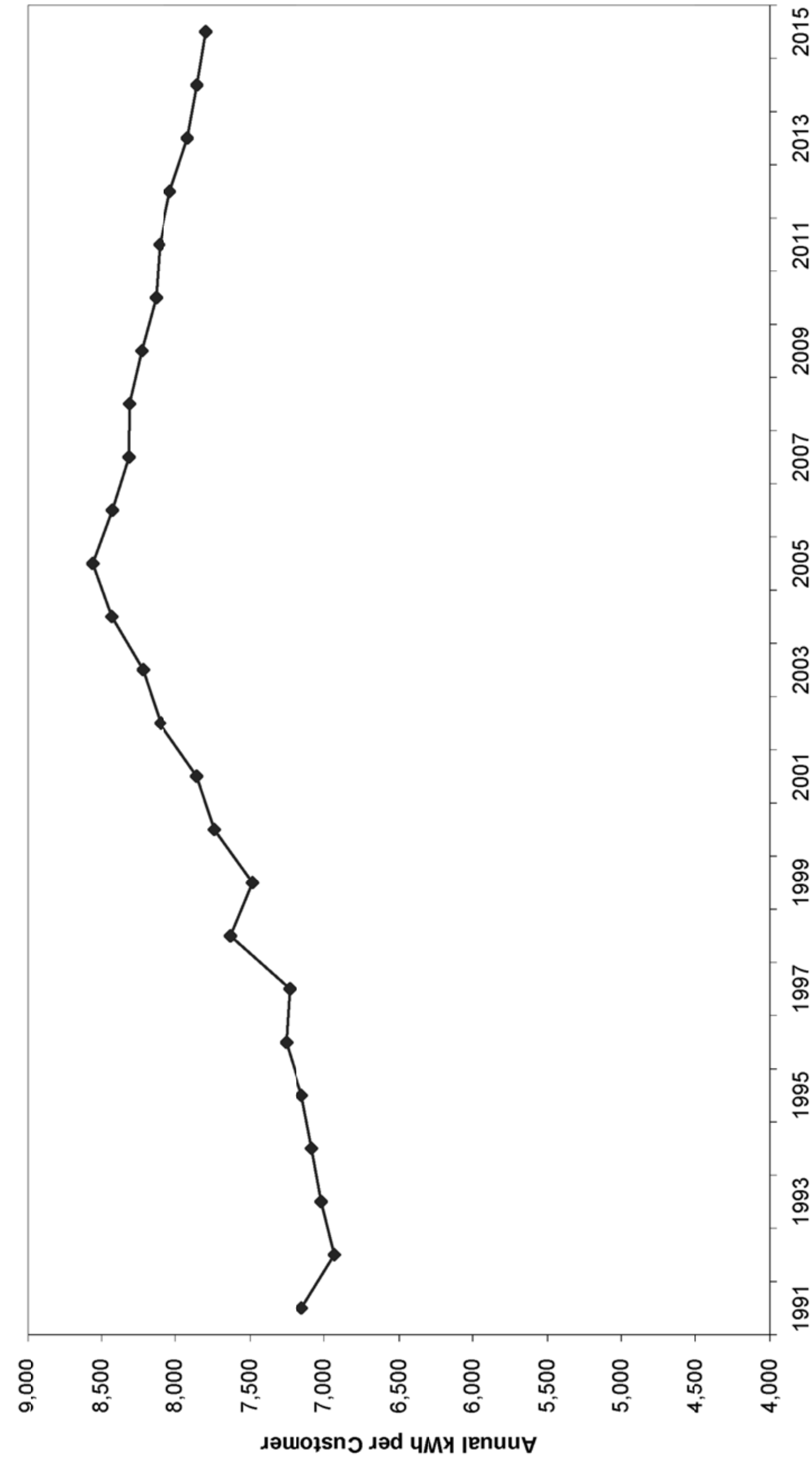
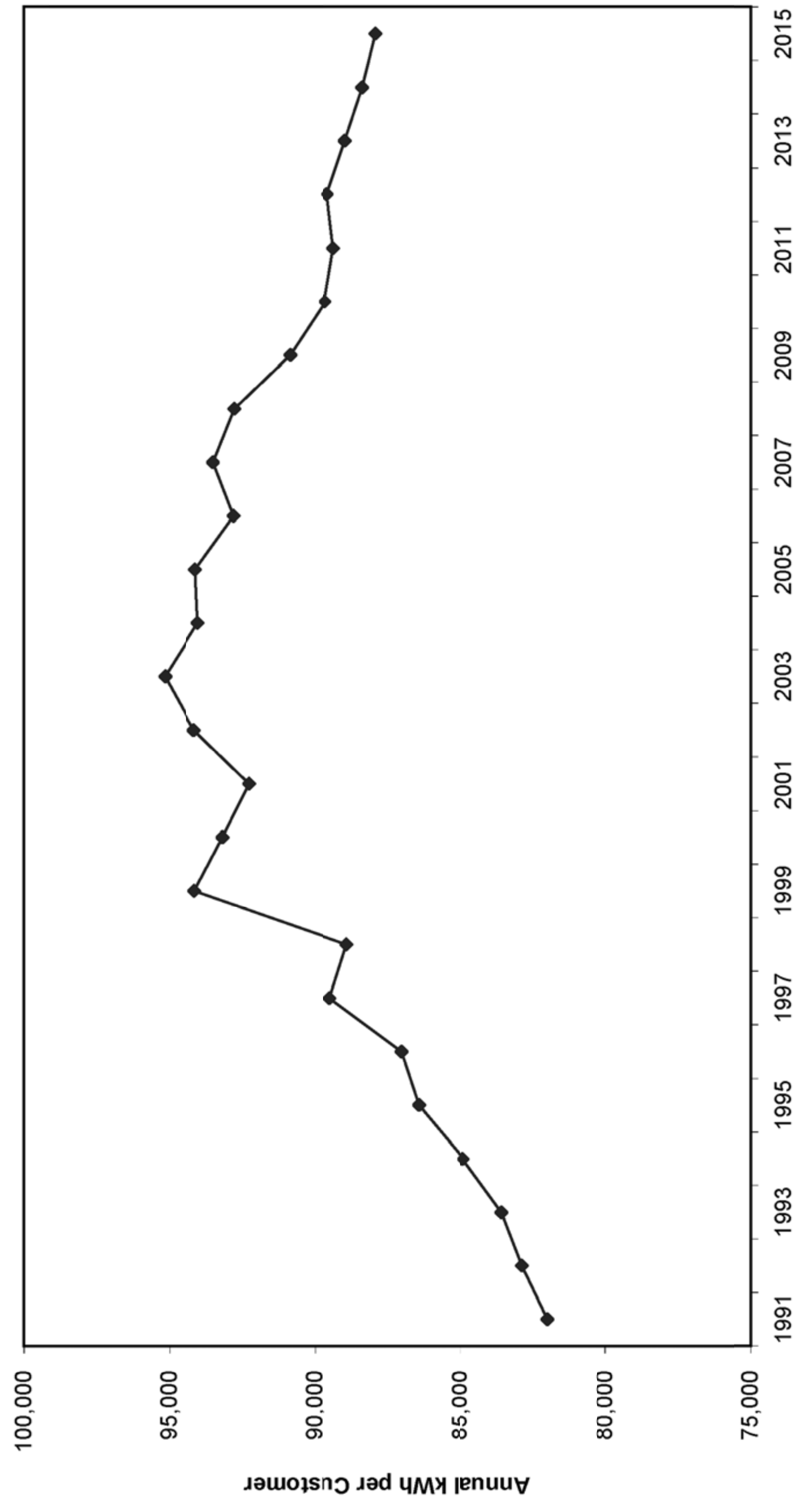


Figure 6b

## ComEd Normalized Small Commercial Average Use Trend



has the lowest administrative cost and the most stable rates, encourages customers to adopt EVs, and is easiest for customers to understand. Volumetric charges would still recover energy supply and transmission costs. SFV pricing may also face the fewest obstacles under Illinois regulatory policy. LRAMs and DSM performance incentives do not reduce utility disincentives to promote electric vehicles and can in principle compensate ComEd for margins lost in eliminating growth in average use. DSM performance incentives have the additional potential benefit of encouraging efficiency in program administration.

Decoupling true up plans also have advantages in an application to ComEd. As with SFV pricing, this approach provides attrition relief and thereby removes disincentives for a wide array of initiatives that ComEd can pursue to promote conservation. Controversy over sales volumes would be reduced in rate cases. Unlike SFV pricing, ComEd could continue its current distribution rate designs and disincentives are removed for experimentation with rate designs, such as inverted block rates and time of use distribution pricing, that encourage more DSM.

The revenue per customer (RPC) approach to decoupling proposed by the NRDC is already used in Illinois in Rider VBA. Rates would be adjusted periodically for any deviation of actual volumes per customer in the target classes from those established in the rate case. This is a feature of numerous approved decoupling true up plans. RPC would be fixed in this rate case based on the approved revenue requirement. Base rate revenue from residential and watt hour business customers would then grow between rate cases only at the gradual pace of customer growth, if any. This is similar to the pace of revenue growth that would be achieved by MFV pricing but does not require MFV pricing.

It should be stressed that the RPC approach is one of the most conservative approaches to the design of a decoupling true up plan. Rate cases would likely still be frequent in order to compensate ComEd for input price inflation and its system modernization program. The majority of plans approved for electric utilities in the United States have, in contrast, provided automatic relief over a multiyear period for a broader array of cost drivers. This alternative approach has certain advantages. Annual rate cases can be avoided and performance incentives can be strengthened. Multi-year budgets can, if desired, be established in advance for AMI and replacement capital investments without the use of trackers. However, the Commission is perfectly free to stick with the more conservative

RPC approach, and even to reset the revenue requirement up to annually via rate cases if it desires upon request for rate relief by ComEd.

Decoupling need not in our view be extended at this time to ComEd's large volume customers, which should assuage concerns they may have about decoupling for small volume customers. A soft cap on revenue adjustments is sensible. If the Commission cares more about rate volatility than it does about plan complexity, it can institute weather normalization of volume variances and/or quarterly rather than annual true ups.

The Commission would also need to consider how best to promote EV adoption if a decoupling true up plan is adopted. One idea would be to exempt EV deliveries from decoupling. Another would be to offer AMI and time of use base rates selectively to customers who use grid power for EVs.

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