



# ***Regulatory Issues in Rate Design, Incentives & Energy Efficiency***



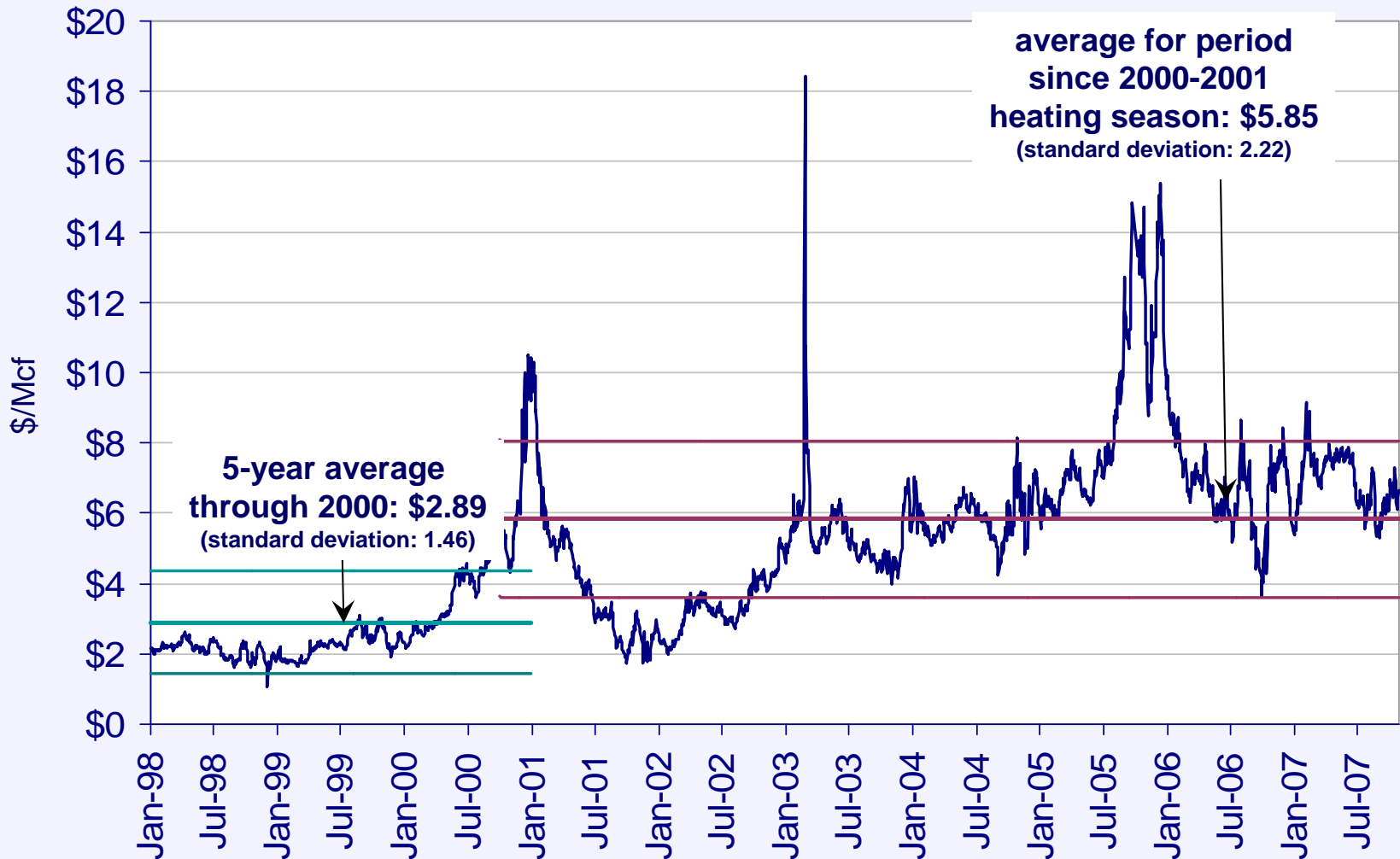
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Director of Policy Analysis  
Center for Energy Studies  
Louisiana State University

**New Hampshire Public Utilities Commission  
November 7, 2007**

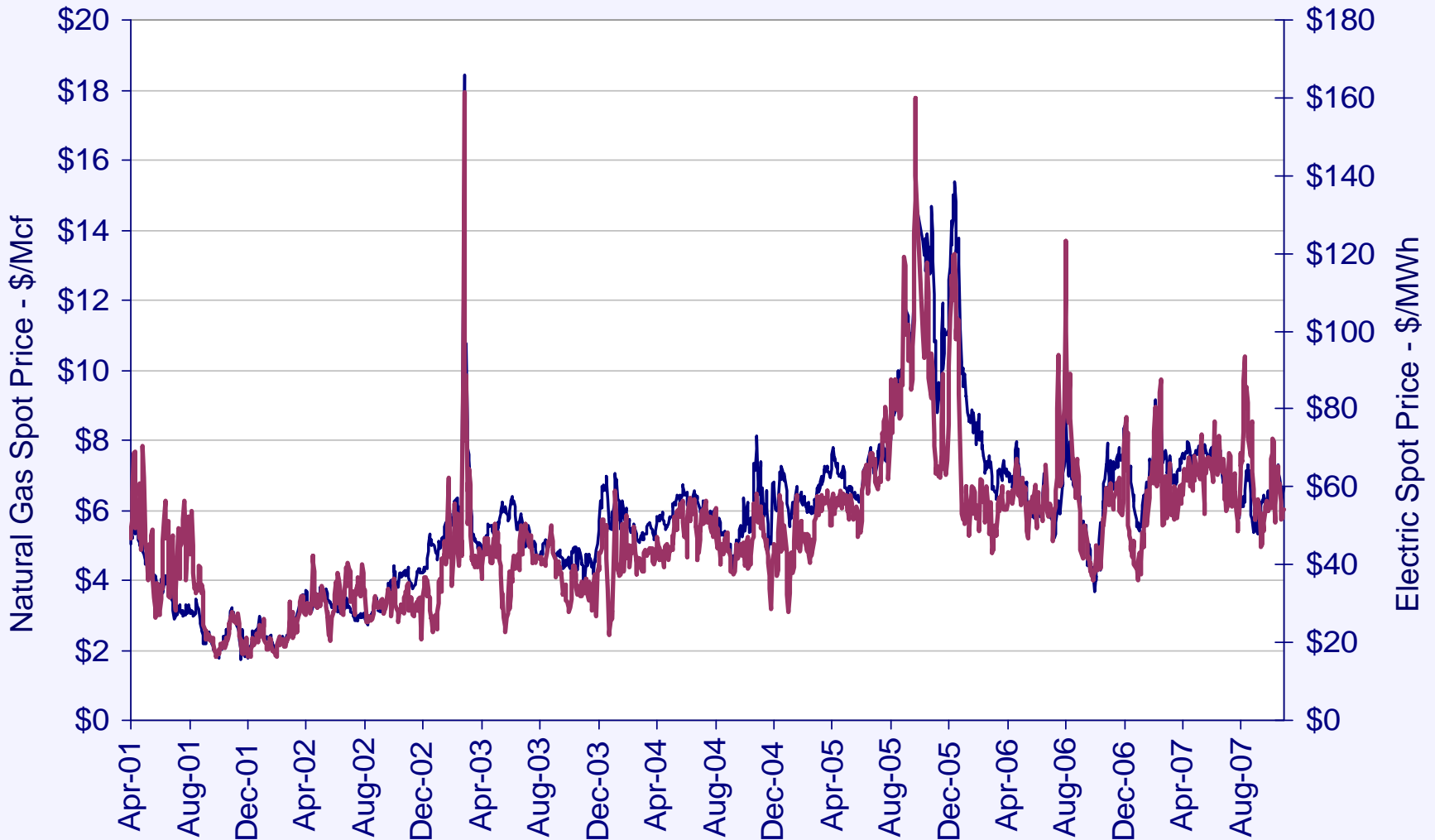
# **Alternatives to Traditional Ratemaking and Their Effects on Energy Efficiency**

- High natural gas prices and volatility.
- Gas impacting power more significantly at the margin.
- Changing usage patterns.
- Emerging need for baseload capacity.
- Regulatory need to “do something soon.”
- Increasing environmental concerns and perceived long-run fossil fuel supply risk.

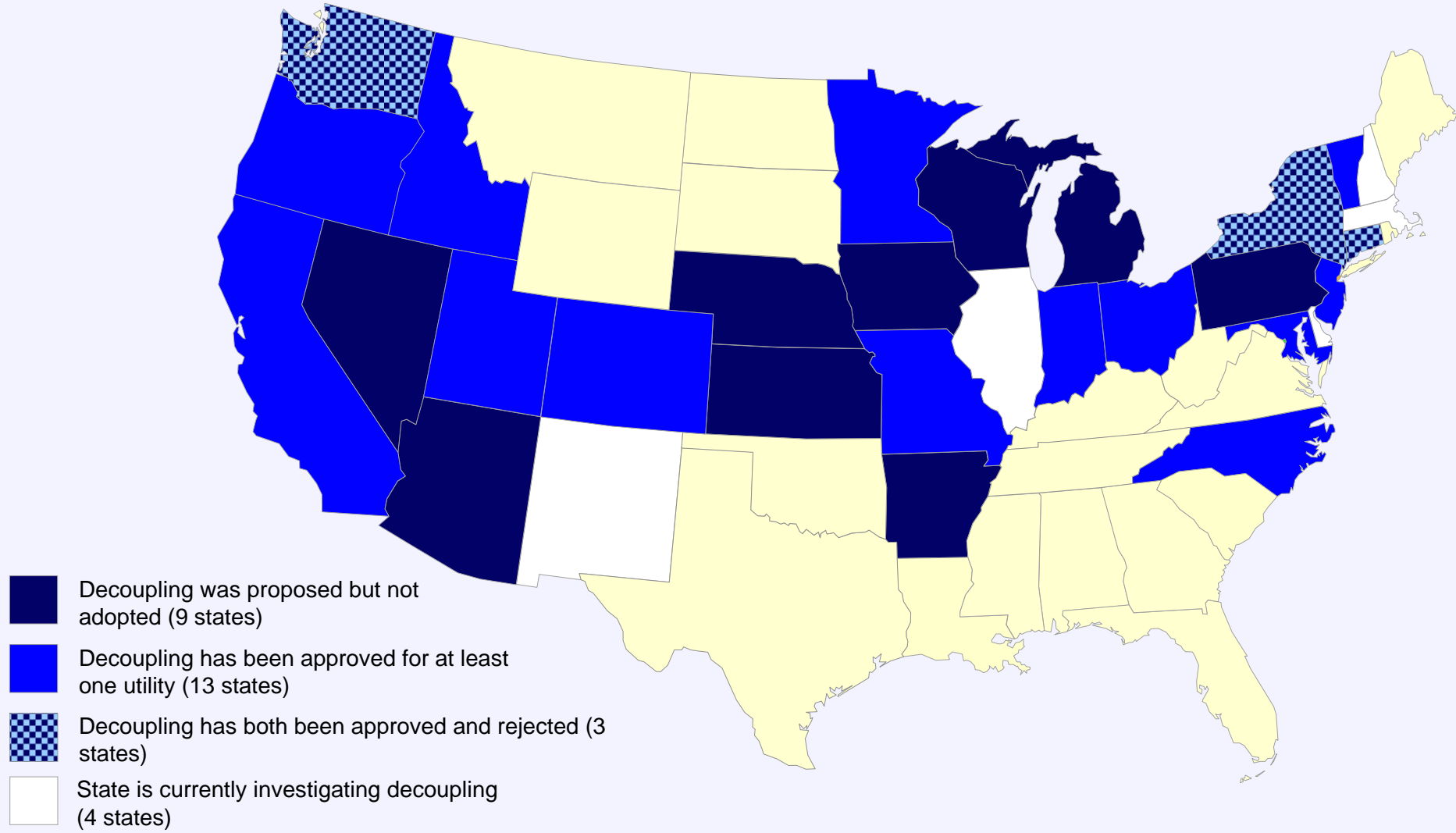
**Increased price levels and volatility faced by LDCs**

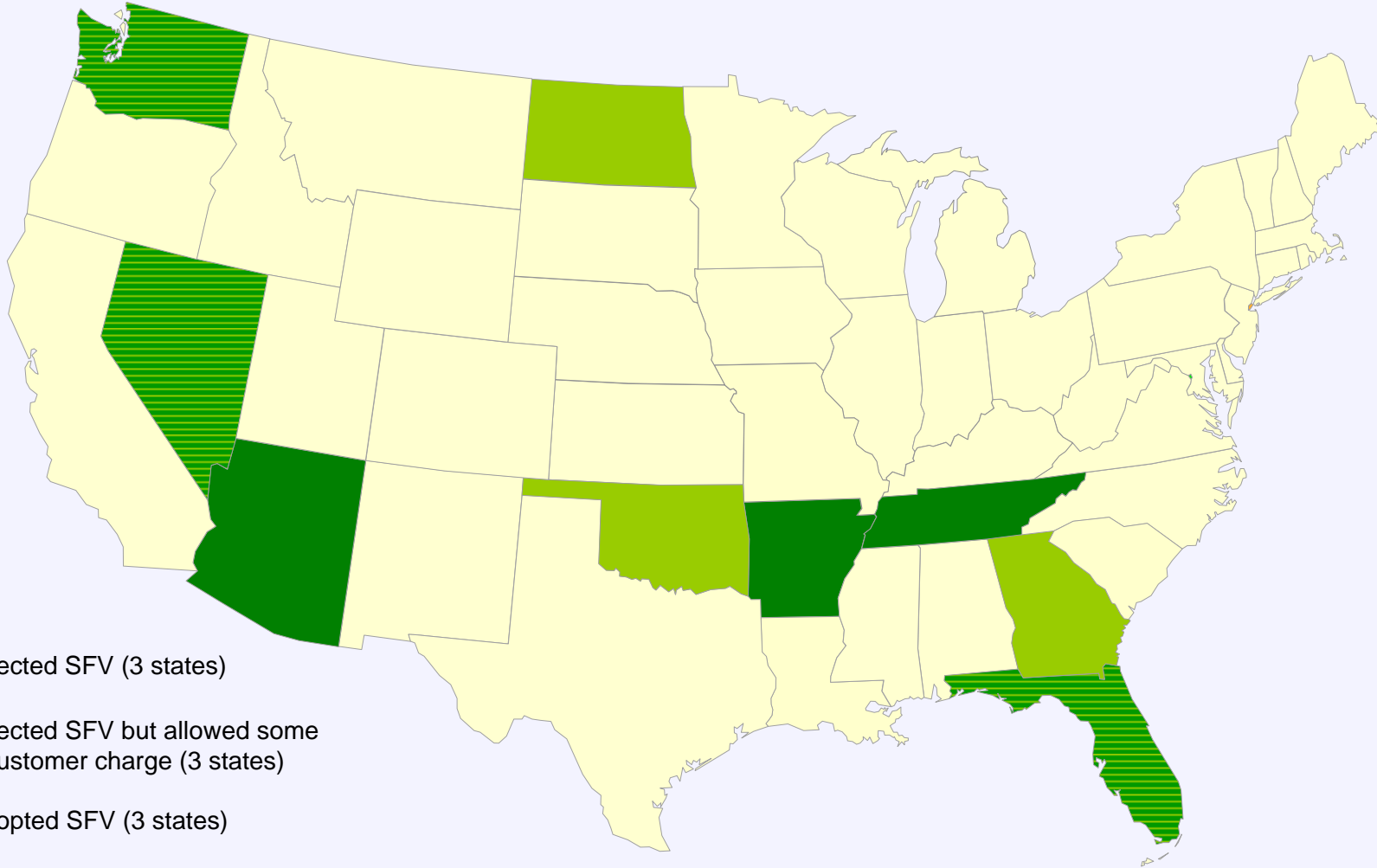


**Increased natural gas prices are also impacting electric utilities through their own generation and purchased power.**



- Rate design practices send the wrong signals to utilities.
- Rates are tied to sales, and in order to increase profits, utilities need to increase sales.
- Utilities will not promote energy efficiency since lower sales result in lower profits.
- The profit incentive to increase sales is extremely powerful.





State has rejected SFV (3 states)

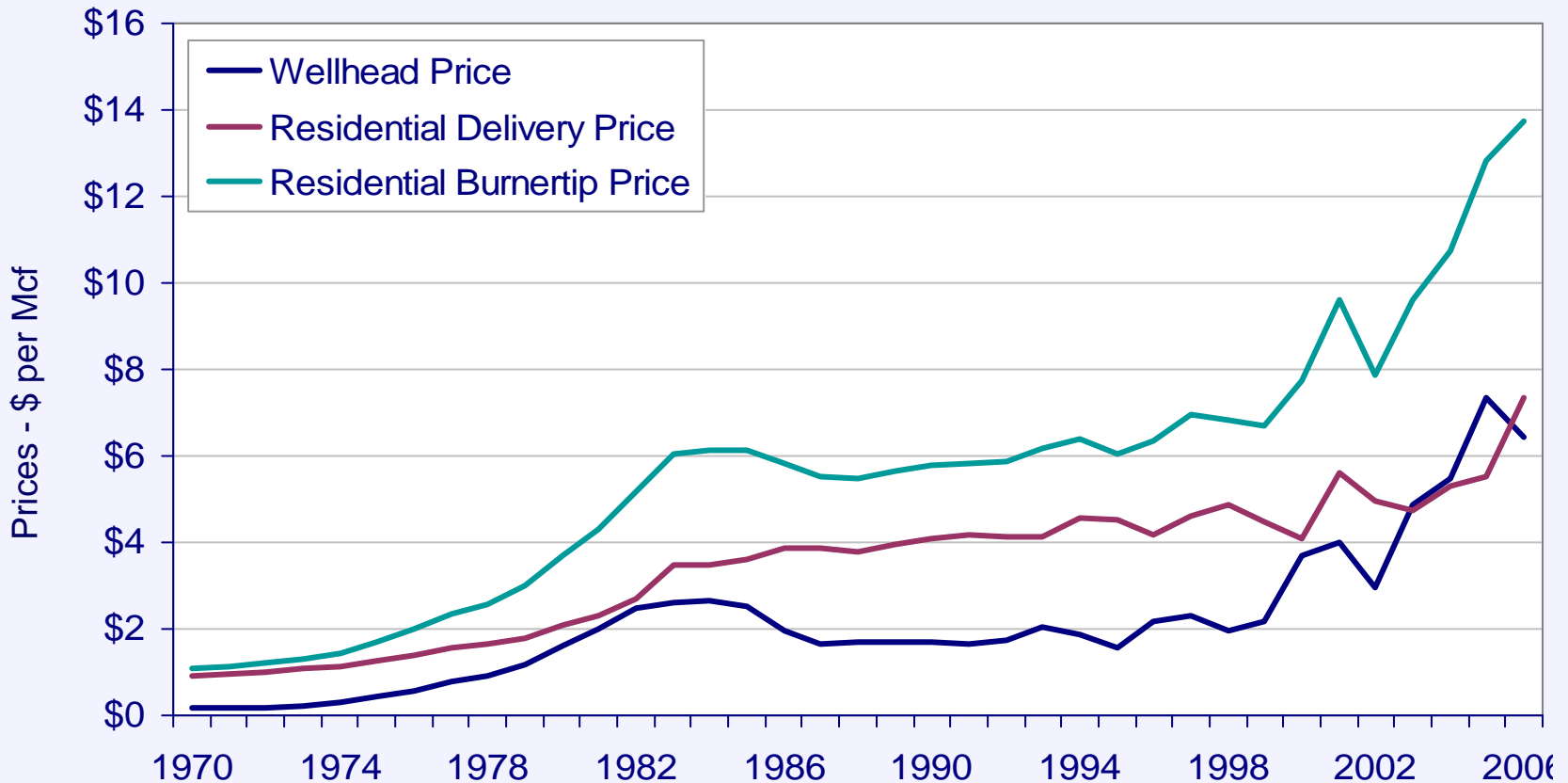


State has rejected SFV but allowed some increase in customer charge (3 states)

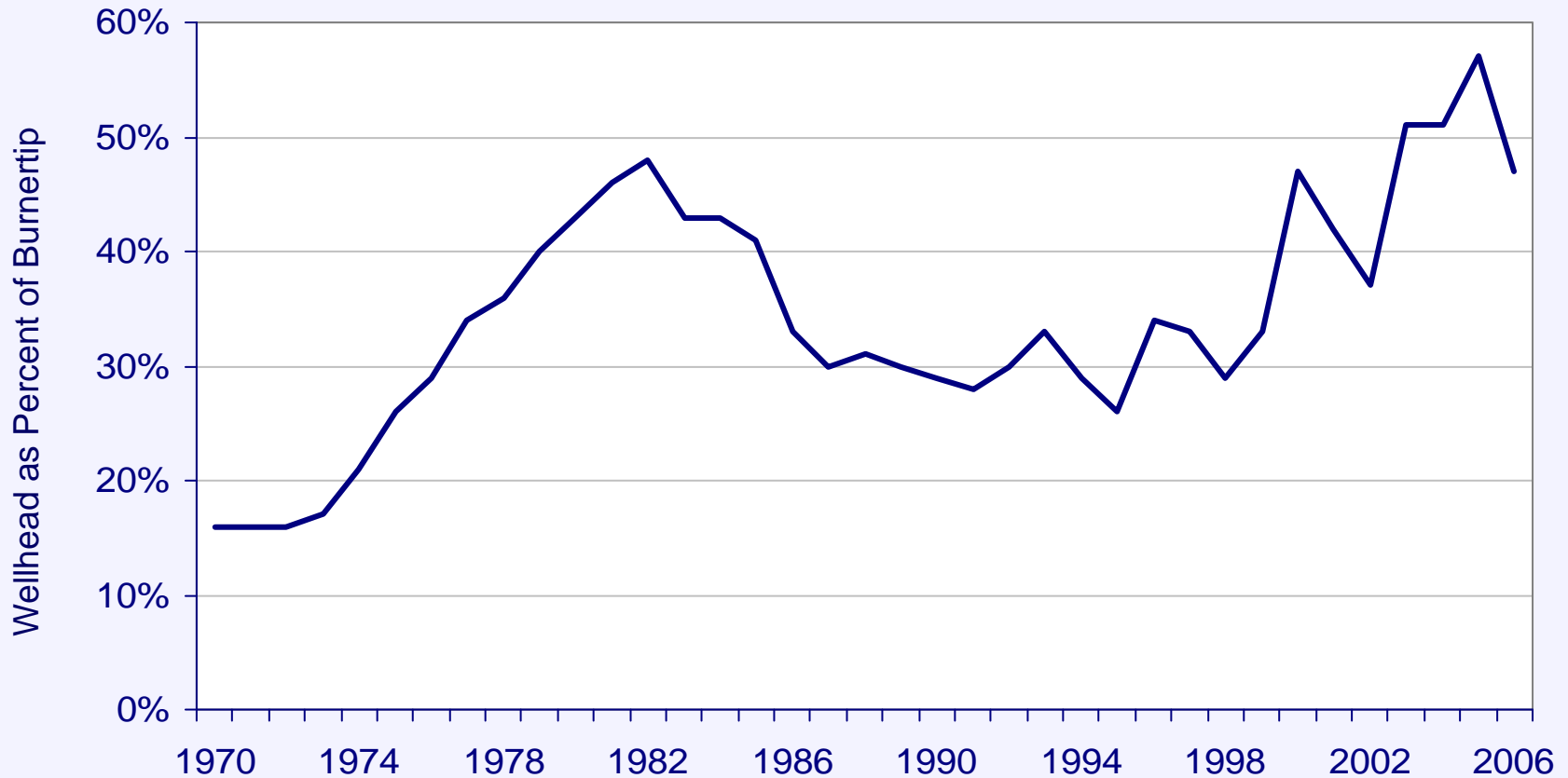


State has adopted SFV (3 states)

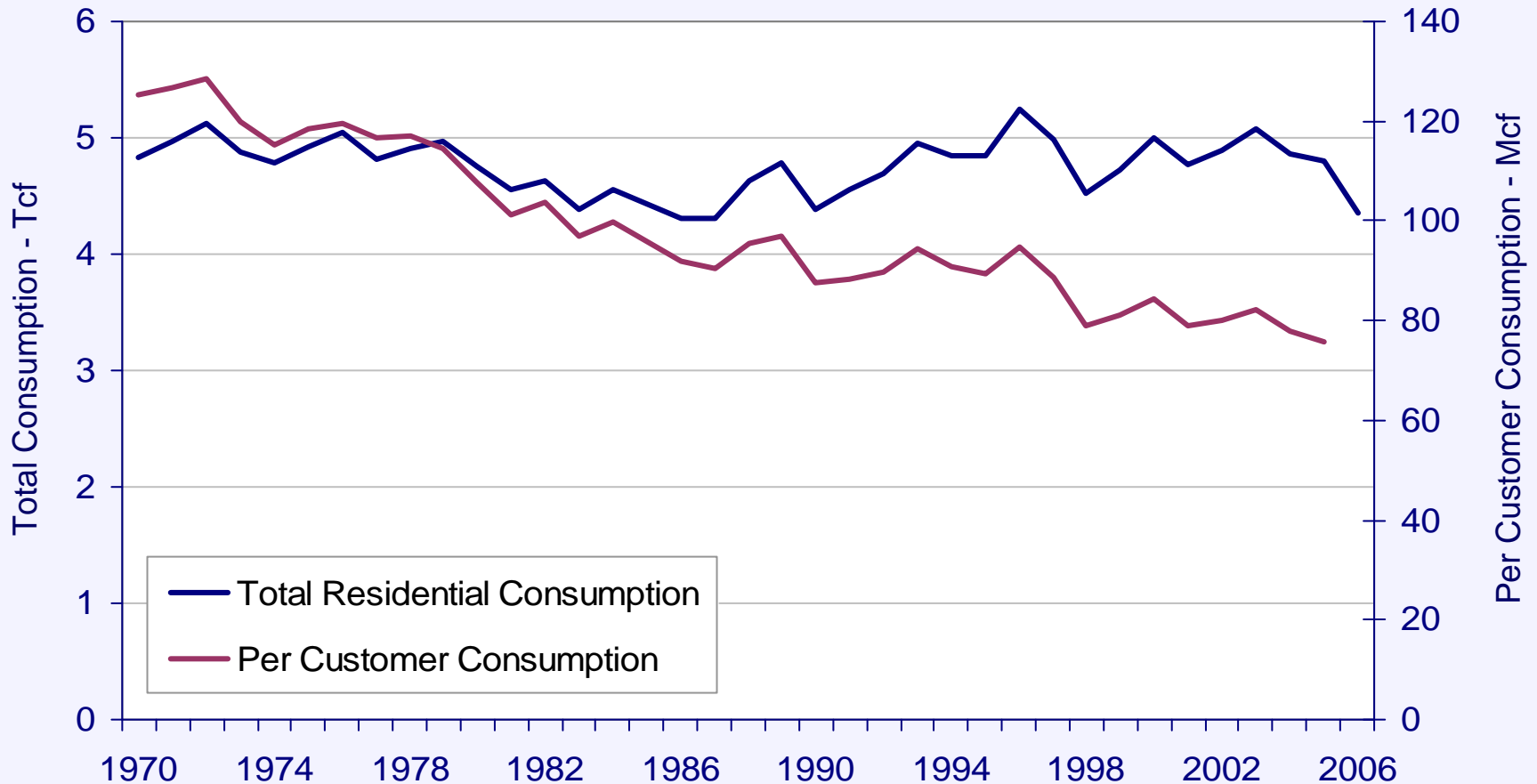
**Retail prices have increased significantly since 2000-2001.**



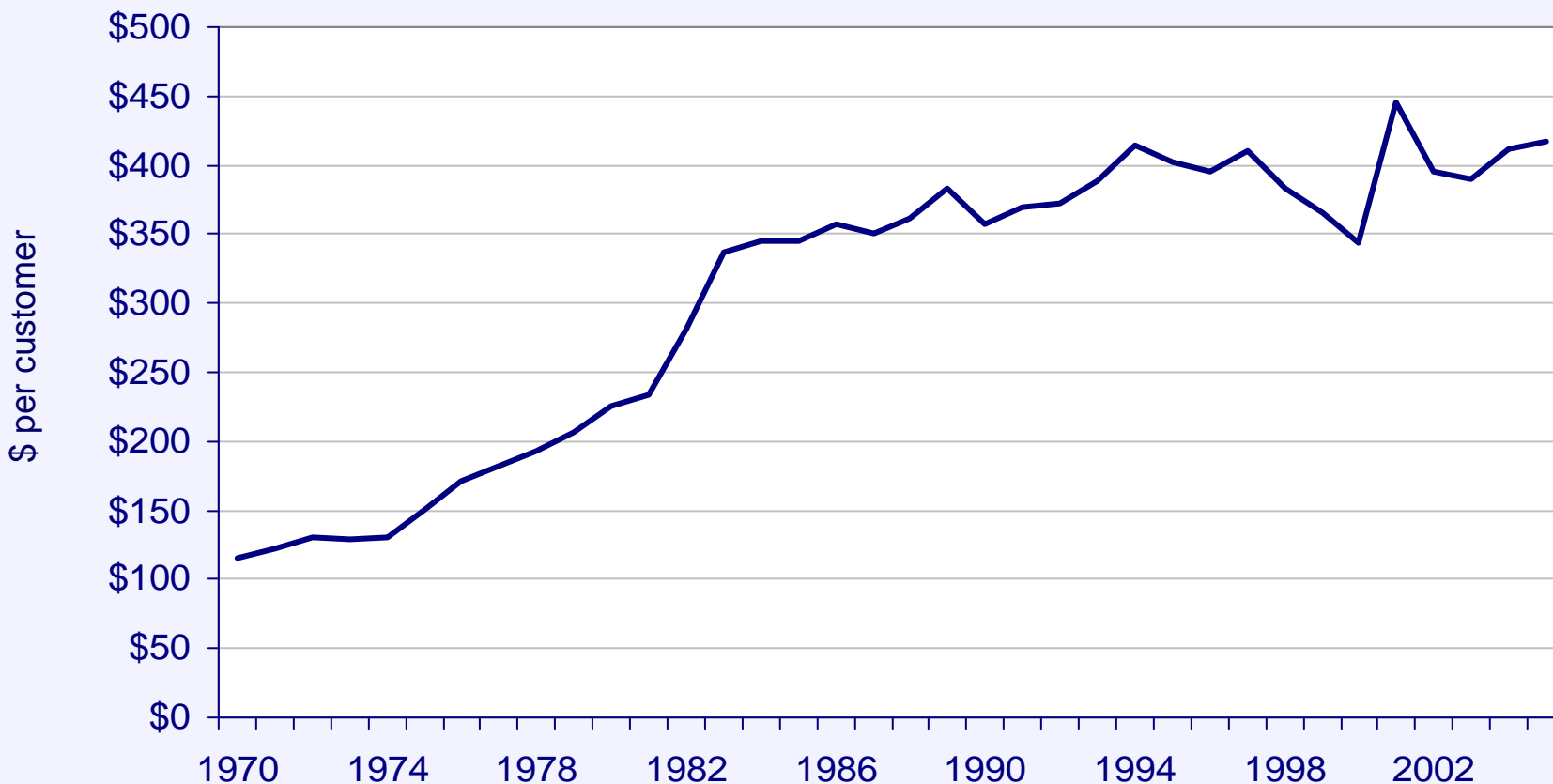
The commodity share of overall natural gas rate has increased over recent years.



**While overall use per customer is decreasing, overall residential natural gas usage is flat to increasing.**



**Yet despite high prices, and decreases in use per customer, overall DNG revenues per customer are at close to historic highs.**

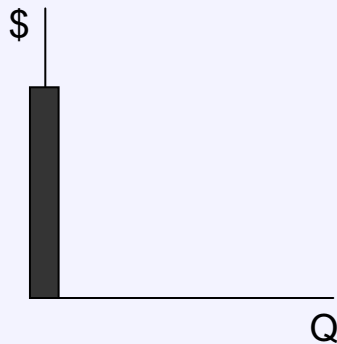


## Rate Design and Energy Efficiency

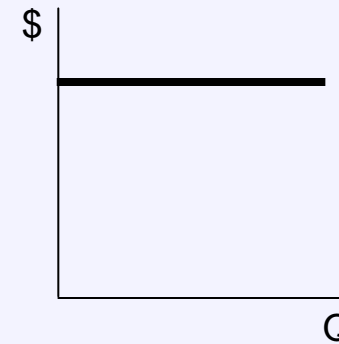
### **Distribution Bill = Fixed Customer Charge + Variable Charge**

- Traditional distribution rate design in utility regulation is referred to as “two-part tariff:” consists of a fixed customer charge, and variable usage charge exclusive of fuel (kWh, MMBtu).
- Also referred to as a “non-linear tariff” since average rates will fall as usage increases.
- Use of this type of pricing claimed to date back to Jules Dupuit’s work on the “Utility of Public Works,” with further work by Frank Ramsey (1927). [see Wilson, *Non-Linear Pricing*.]
- Use of this type of tariff in utility pricing is dated back to the early part of the 20<sup>th</sup> century by an English engineer named John Hopkinson. [see Kahn, *Economics of Regulation*.]
- Since that time, there have been numerous utility pricing structures based off the two-part tariff approach.

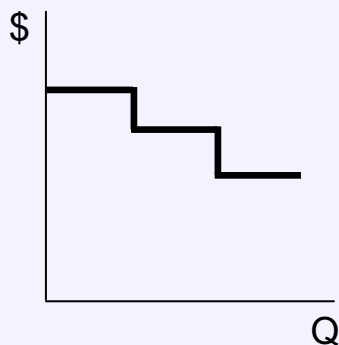
**flat rate per period,  
no usage charge**



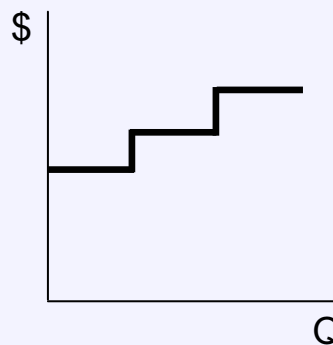
**uniform: flat rate per unit**



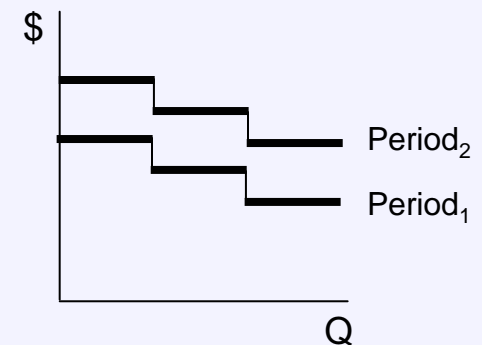
**declining block**



**inverted block**



**seasonal or time-of-use**



## How Does Decoupling Work?

- Straight-Fixed Variable Rate Design: eliminates all variable distribution charges and assigns fixed customer charge alone (gas LDCs).
- Revenue Decoupling (Use Per Customer): separates revenue recovery from sales on a “per-customer” target. Allows utility to recover revenue growth from increases in customers
- Revenue Decoupling (Revenue Cap): restricts total revenue recovery to allowed test year levels. Can include some adjustments for attrition/inflation.

## Example of Revenue Decoupling Allowing for Customer Growth

### Allowed Revenue per Customer (Annual)

|                                   |                |
|-----------------------------------|----------------|
| Current Non-Gas Revenue           | \$ 150,000,000 |
| 2005 Number of Customers          | 600,000        |
| Volumetric Charge<br>per Customer | \$250.00       |

### Allowed Revenue per Customer (Monthly)

|              | Test<br>Year     | Forecasted<br>Allowed |
|--------------|------------------|-----------------------|
| January      | \$ 24.61         | \$ 22.81              |
| February     | \$ 23.02         | \$ 21.33              |
| March        | \$ 18.47         | \$ 17.12              |
| April        | \$ 20.84         | \$ 19.32              |
| May          | \$ 22.85         | \$ 21.18              |
| June         | \$ 22.31         | \$ 20.68              |
| July         | \$ 19.72         | \$ 18.28              |
| August       | \$ 21.09         | \$ 19.55              |
| September    | \$ 25.95         | \$ 24.05              |
| October      | \$ 27.02         | \$ 25.05              |
| November     | \$ 17.58         | \$ 16.29              |
| December     | \$ 26.25         | \$ 24.33              |
| <b>Total</b> | <b>\$ 269.71</b> | <b>\$ 250.00</b>      |

### Revenue Decoupling Tariff Example for January 2006

|   |                  |
|---|------------------|
| Allowed DNG Revenue<br>per Customer                 | \$ 22.81         |
| Actual Customers                                    | 610,000          |
| <hr/>   |                  |
| Allowed DNG Revenue<br>for Month                    | \$13,914,100     |
| Actual DNG Revenue<br>for Month                     | \$13,650,000     |
| <hr/>   |                  |
| <b>CET Monthly Accrual<br/>to Balancing Account</b> | <b>\$264,100</b> |
| <b>Accrual Added to<br/>Monthly Bill</b>            | <b>\$0.433</b>   |
| <b>New Monthly Charge</b>                           | <b>\$23.24</b>   |

## Example of Revenue Decoupling Revenue Cap Approach & Comparison

| <b>Revenue Decoupling Tariff<br/>Example for January 2006</b> |                  |
|---|------------------|
| Allowed DNG Revenue per Customer                              | \$ 22.81         |
| Actual Customers  | 610,000          |
| <hr/>   |                  |
| Allowed DNG Revenue for Month                                 | \$13,914,100     |
| Actual DNG Revenue for Month                                  | \$13,650,000     |
| <hr/>   |                  |
| <b>CET Monthly Accrual to Balancing Account</b>               | <b>\$264,100</b> |
| <b>Accrual Added to Monthly Bill</b>                          | <b>\$0.433</b>   |
| <b>New Monthly Charge</b>                                     | <b>\$23.24</b>   |

| <b>Revenue Decoupling Tariff<br/>Example for January 2006</b> |                 |
|---|-----------------|
| Allowed DNG Revenue per Customer                              | \$ 22.81        |
| Actual Customers  | 600,000         |
| <hr/>   |                 |
| Allowed DNG Revenue for Month                                 | \$13,686,000    |
| Actual DNG Revenue for Month                                  | \$13,650,000    |
| <hr/>   |                 |
| <b>CET Monthly Accrual to Balancing Account</b>               | <b>\$36,000</b> |
| <b>Accrual Added to Monthly Bill</b>                          | <b>\$0.06</b>   |
| <b>New Monthly Charge</b>                                     | <b>\$22.87</b>  |

## Relative Impacts on Customers and Shareholders?

- Aligns utility incentives with energy efficiency.
- Assists utility in earning its authorized rate of return that is challenged by the decreasing use per customer problem (gas).
- Easier for customers to understand and reduces bill volatility.
- Reduces regulatory costs and the need for frequent rate cases.

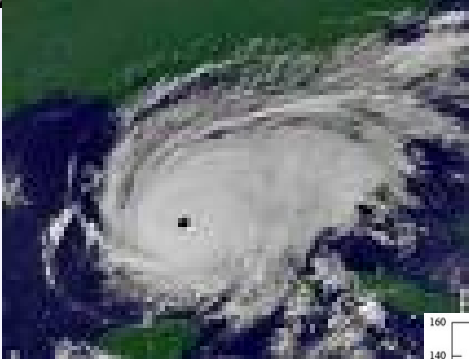
- **Shifts sales risks from utilities to customers.**
- **The impact of changes in use per customer for the gas industry are different than power industry. However, both are experiencing growth.**
- **At best, the incentive issue is not resolved with revenue decoupling.**
- **Current proposals, offered in conjunction with other “regulatory remedies” diminishes the simplicity argument and raises questions about the purpose of proposal.**
- **Proportionality issue – changing the rate design for all customers based upon programs for which an exceptionally small percentage of the customers will participate.**

- Base rates are typically fixed and based upon an allowed rate of return under traditional regulation
- Between rate cases, actual rates of return can vary from allowed.
- Regulatory lag can provide important incentives and has been harnessed in many incentive regulation structures.
- Between rate cases, it is up to the utility to manage risk associated with sales (revenue) and find opportunities for efficiency (cost).

**Economy**

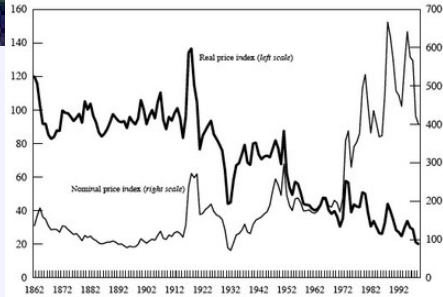


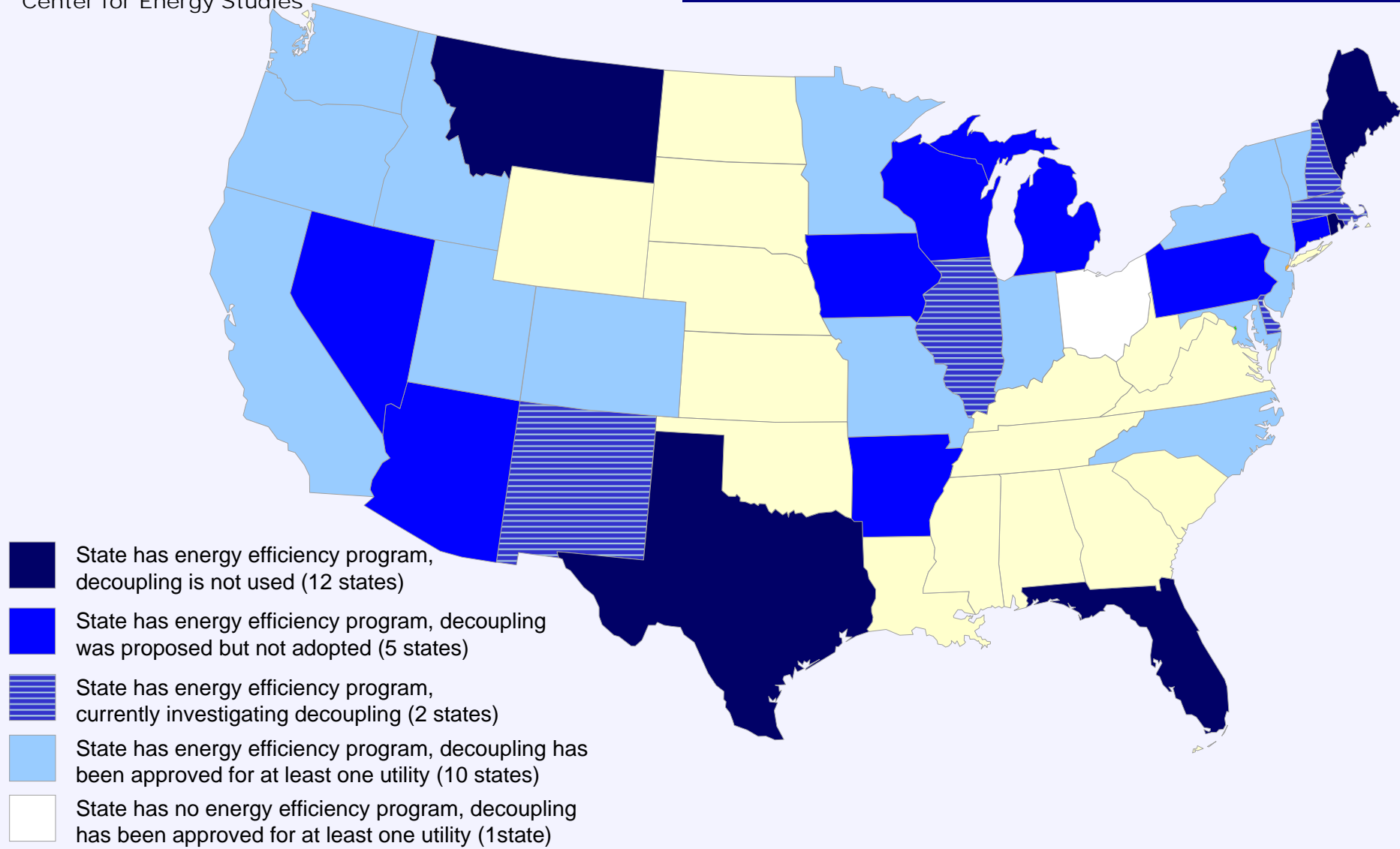
**Weather**



**Commodity Prices**

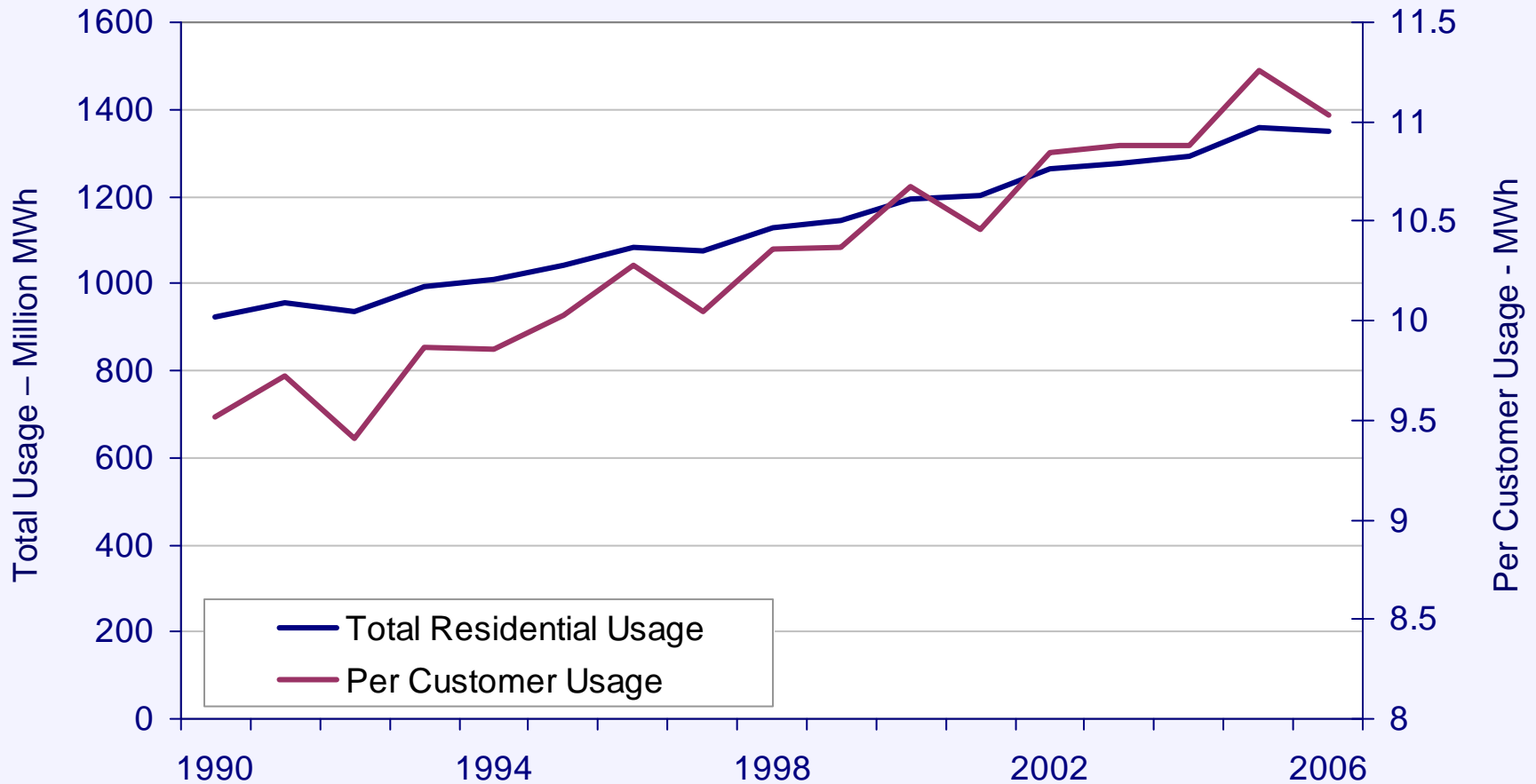
**Other Unanticipated Factors**



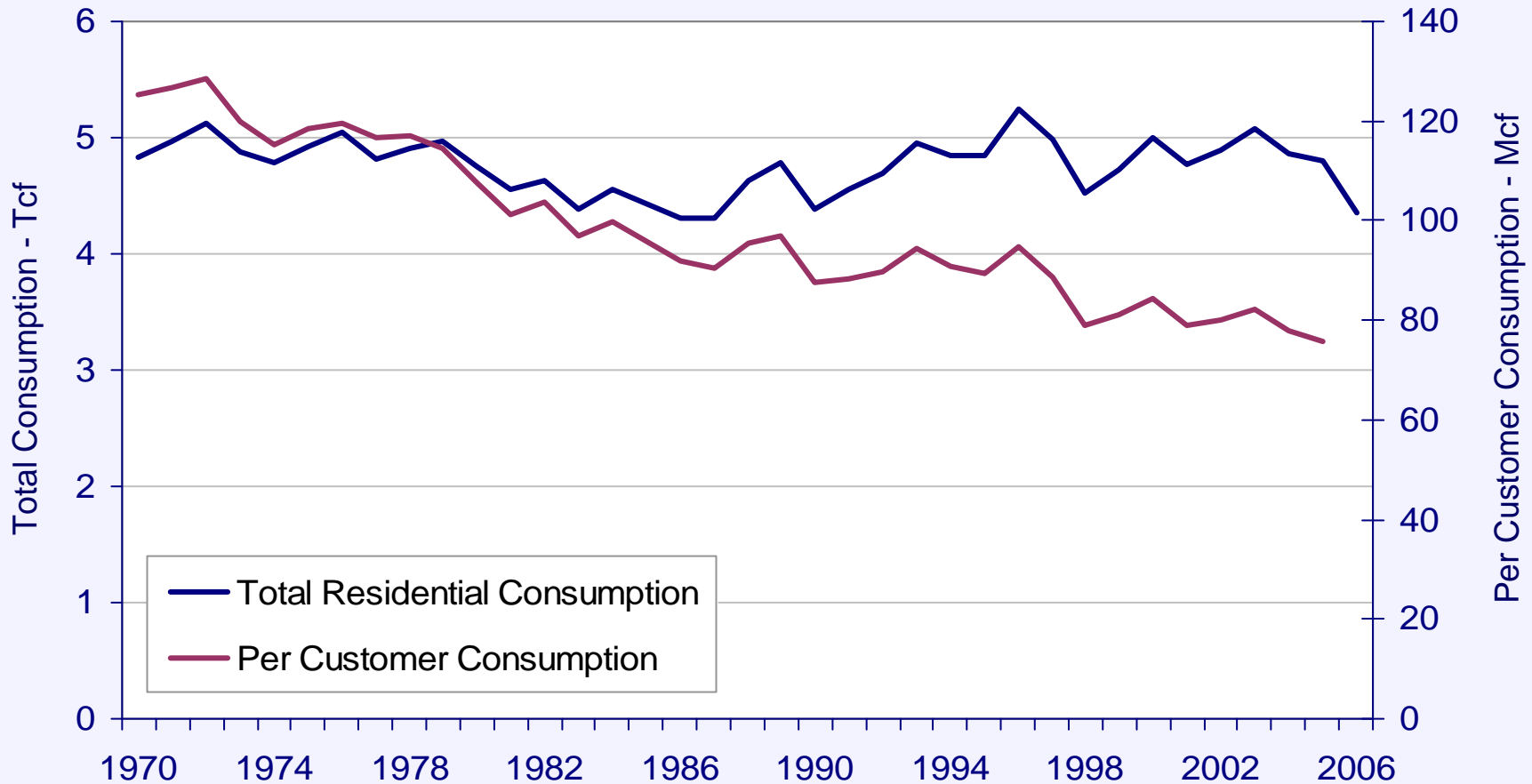


Note: In Connecticut, the electric utilities do not have decoupling, but two natural gas LDCs have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a conservation adjustment mechanism). Washington has utilities with decoupling, but rejected the most recent utility proposal (January 2007).

**In the electric industry, use per customer and total usage are increasing unlike retail residential natural gas trends.**



**While overall use per customer is decreasing, overall residential natural gas usage is flat to increasing.**



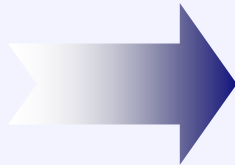
**Typical energy efficiency advocate/LDC example: one percent decrease in annual sales will result in significant revenue (financial) harm to utility.**

| <b>Revenue Loss</b>            | <b>Year 1</b>       | <b>Year 2</b>       | <b>Year 3</b>       |
|--------------------------------|---------------------|---------------------|---------------------|
| Year 1                         | \$ 1,554,593        | \$ 1,554,593        | \$ 1,554,593        |
| Year 2                         |                     | \$ 1,567,434        | \$ 1,567,434        |
| Year 3                         |                     |                     | \$ 1,587,600        |
| <b>Annual Revenue Loss</b>     | <b>\$ 1,554,593</b> | <b>\$ 3,122,027</b> | <b>\$ 4,709,627</b> |
| <b>Cumulative Revenue Loss</b> | <b>\$ 1,554,593</b> | <b>\$ 4,676,620</b> | <b>\$ 9,386,247</b> |

**Do you really want the LDC to suffer a \$9 million loss for “doing the right thing?”**

|              | Change in Revenue    |                      |                      | Income Impact        |                      |                      | Shareholders Equity | Impact on ROE       |
|--------------|----------------------|----------------------|----------------------|----------------------|----------------------|----------------------|---------------------|---------------------|
|              | Use per Customer     | DSM                  | New Customers        | Use per Customer     | DSM                  | New Customers        |                     |                     |
| 2007         | \$(1,971,361)        | \$ (288,537)         | \$ 6,678,084         | \$(1,221,185)        | \$ (178,738)         | \$ 4,136,826         | \$ 311,617,637      | 0.88%               |
| 2008         | \$(2,905,519)        | \$ (608,826)         | \$ 6,052,305         | \$(1,799,862)        | \$ (377,145)         | \$ 3,749,179         | \$ 313,189,810      | 0.50%               |
| 2009         | \$(4,485,340)        | \$ (943,652)         | \$ 5,884,186         | \$(2,778,502)        | \$ (584,557)         | \$ 3,645,035         | \$ 313,471,786      | 0.09%               |
| <b>Total</b> | <b>\$(9,362,220)</b> | <b>\$(1,841,015)</b> | <b>\$ 18,614,574</b> | <b>\$(5,799,549)</b> | <b>\$(1,140,440)</b> | <b>\$ 11,531,040</b> |                     | <b>1.47%</b>        |
|              |                      |                      |                      |                      |                      |                      | <b>Net Impact:</b>  | <b>\$ 4,591,051</b> |

## Exaggerated Example



- Reduced revenues/income reduces overall taxes and needs to be considered.
- A one percent per year (3 percent cumulative) reduction is beyond current experience.
- The additional income created by customer growth from the test year is completely ignored (and its corresponding income effects).
- Net impact for a growing LDC is moderate – the net income impact is still positive, not negative.

**Difficult to accept the “simplicity” argument when utilities typically propose a potpourri of adders and trackers alongside revenue neutrality.**

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**Customer groups are “tracker fatigued.”**

- Purchased Gas Adjustment/Power Recovery Mechanisms
- Weatherization Clauses
- Shifts to 15 Year Normalization Periods
- Infrastructure Recovery Riders
- Lost and Unaccounted for Gas (LAUF) in PGA/GCR
- Uncollectibles Rider

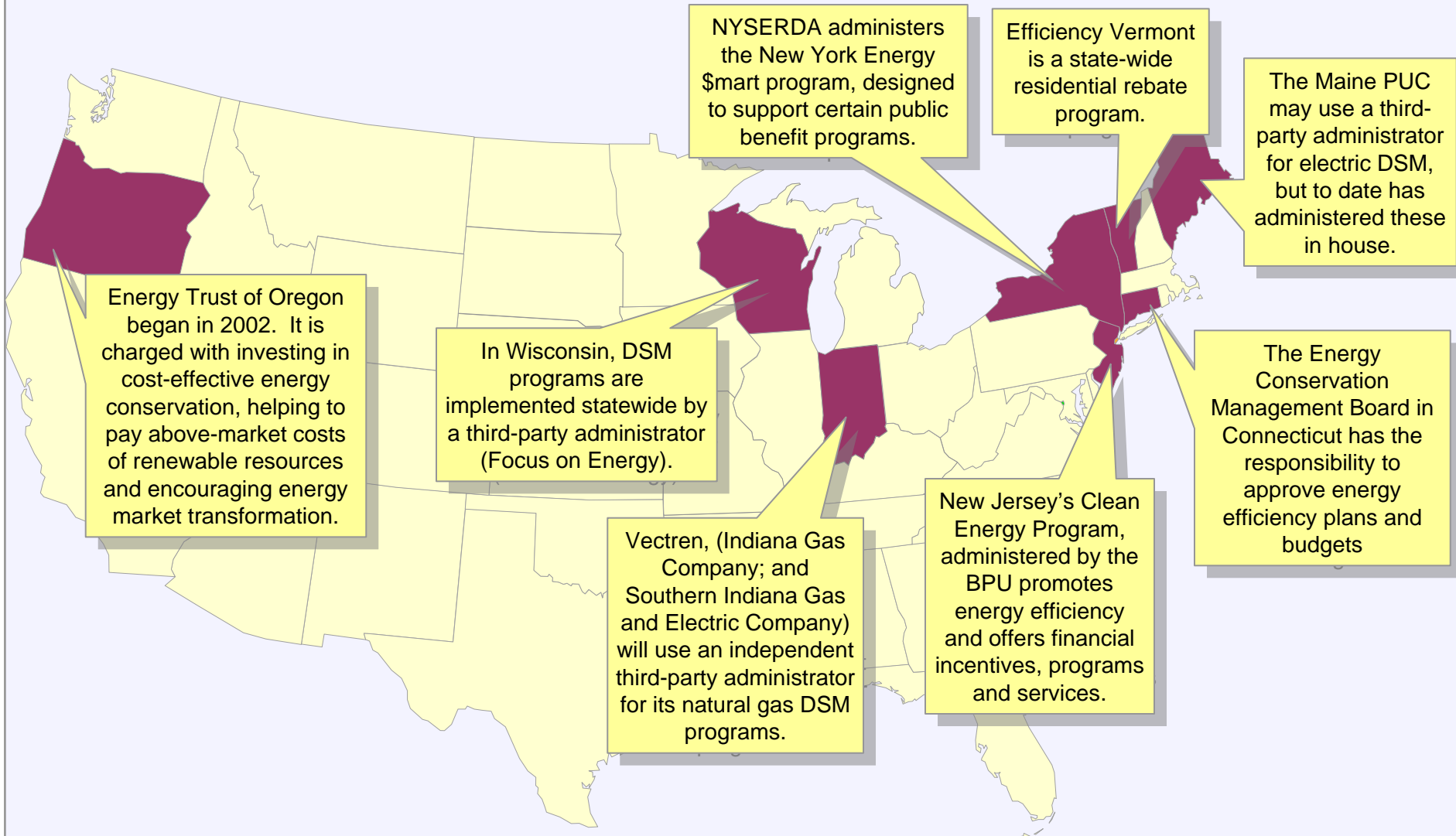
**Significant change in rate design for a very small change in overall sales and very limited number of customers.**

|                       | Program Spending (million \$) | Percent of Retail Revenues (%) | Gas Savings (Mcf/year) | Percent of Gas Sales Saved (%) | Volume saved per million \$ (Mcf/year) | Benefit-Cost Ratio |
|-----------------------|-------------------------------|--------------------------------|------------------------|--------------------------------|--|--------------------|
| Aquila                | \$ 2.10                       | 1.4%                           | 146,000                | 0.5%                           | 69,000                                 | -                  |
| Centerpoint           | \$ 5.60                       | 0.5%                           | 720,000                | 0.5%                           | 128,600                                | 2.60               |
| Keyspan               | \$ 12.00                      | 1.0%                           | 490,000                | 0.4%                           | 41,000                                 | 3.00               |
| Northwest Natural Gas | \$ 4.70                       | 0.7%                           | 85,000                 | 0.1%                           | 18,000                                 | -                  |
| NSTAR                 | \$ 3.90                       | 0.8%                           | 71,500                 | 0.2%                           | 18,000                                 | 2.29               |
| PG&E                  | \$ 13.50                      | 0.4%                           | 2,000,000              | 0.7%                           | 148,000                                | 2.10               |
| PSE                   | \$ 3.80                       | 0.4%                           | 311,000                | 0.5%                           | 82,275                                 | 1.93               |
| SoCal Gas             | \$ 21.00                      | 0.6%                           | 1,100,000              | 0.3%                           | 52,000                                 | 2.67               |
| Vermont Gas           | \$ 1.10                       | 1.6%                           | 57,000                 | 1.0%                           | 52,000                                 | 5.60               |
| Xcel Energy (MN)      | \$ 4.00                       | 0.7%                           | 663,000                | 0.9%                           | 166,000                                | 1.56               |

**Generally, less than one-half of one percent.**

- **Projected test years:** forecasts could account for anticipated energy efficiency savings.
- **Cost-effectiveness tests:** screening on RIM-passing measures only.
- **Lost Revenues (ex post):** periodic filings on proven, *ex post* lost revenues/sales.
- **Rate design (inclining blocks):** higher rates in upper blocks.
- **Repression adjustments:** usage adjustment to correct of DSM-related reductions in usage.
- **Direct Incentives:** performance-based incentives for programs.
- **Risk Management:** if volatility is an issue, then manage it.
- **More frequent rate cases:** traditional approach at correcting rates that get out of balance.

- **Caps:** absolute dollar caps can be placed on the balances to ensure any pass throughs are limited.
- **Statistical Recoupling:** using empirical information from load forecasts to “recouple” the risk associated with weather, economy, and prices back to utility.
- **ROE Adjustment:** lower the allowed ROE to reflect changing risk.
- **“K” Factor or “Z” Factor:** built in efficiency adjustment to recouple risk back to utility.





## Selected Recommendations on ROE Adjustments for Revenue Neutrality Mechanisms

| Jurisdiction | Company                          | Docket/Case                      | Proposed Change to Rate Structure       | Cost of Capital Proposal   | Adjustment  |
|--------------|----------------------------------|----------------------------------|---|--|---|
| Arkansas     | CenterPoint Energy Arkla         | Docket No. 04-121-U              | Load Change Adjustment Rider            | Attorney General witness W.B. Marcus states, "... recognizing that I already included a small risk-reducing impact of the existing weather normalization mechanism in my estimated rate of return, I would recommend a further 35-basis point adjustment for risk if the LCA were adopted."  | 0.35 adjustment to rate of return                                   |
| Arizona      | Southwest Gas                    | Docket No. G-01551A-04-0876      | Conservation Margin Tracker             | Southwest Gas recommends that the Commission determine the Company's cost of common equity to be 11.42 percent if its proposed CMT is not adopted and 11.17 percent with adoption of the CMT. The Company's cost of capital recommendation is 9.4 percent without the CMT and 9.29 percent with the CMT  | 0.25 reduction to cost of equity; 0.11 reduction to cost of capital |
| Delaware     | Delmarva Power & Light Company   | Docket No. 06-284                | Bill Stabilization Adjustment           | Delmarva witness Roger Morin recommends "the adoption of an overall return on investment of 8.08% and a rate of return on common equity of 11.0% on DP&L's natural gas delivery operations, assuming that the Bill Stabilization Adjustment ("BSA") is adopted. If the BSA adopted is not approved, I recommend the adoption of an overall return on investment of 8.20% and a rate of return on common equity of 11.25% on DP&L's natural gas delivery operations." | 0.25 reduction to cost of equity; 0.12 reduction to cost of capital |
| Nevada       | Southwest Gas                    | Docket No. 04-3011               | Margin per Customer Balancing Provision | Southwest's witness, Frank J. Hanley, "...recommends an 11.75 percent cost of common equity, which recognizes Southwest is riskier than other relatively comparable local distribution companies. However, he states, if the Commission approves the proposed Margin per Customer Balancing Provision, he recommends the common equity cost rate be reduced by 25 basis points to 11.50 percent."  | 0.25 reduction to cost of equity                                    |
| Tennessee    | Chattanooga Gas                  | Docket No. 06-00175              | Conservation and Usage Adjustment       | Chattanooga witness, Dr. Roger A. Morin concluded that "a just and reasonable return on common equity ("ROE") for CGC at this time is 11.5%. If the Company's proposed Conservation and Usage Adjustment rider (CUA) and Pipeline Replacement Program (PRP) mechanism are approved, it is my opinion that a just and reasonable ROE for CGC is 11.0%."   | 0.50 reduction to cost of equity                                    |
| Vermont      | Green Mountain Power Corporation | Docket No. 7175; Docket No. 7176 | Alternative Regulation Plan             | GMP and the DPS signed a MOU agreeing that GMP's Plan "provides for regular (quarterly) rate adjustments to flow through to ratepayers increases or decreases in power costs (which make up the majority of GMP's total costs). This has the effect of shifting risk associated with varying power costs to ratepayers; in recognition of this risk shift, the Plan provides a lower return on equity."  | 0.50 reduction to cost of equity                                    |



## Questions, Comments, & Discussion

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