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Environmental Energy Technologies Division

March 2009

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## Disclaimer

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## Acknowledgements

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## Acronyms and Abbreviations

| | |
|---|---|
| APS | Arizona Public Service |
| BAU | Business-as-usual |
| CapEx | Capital expenditure |
| CCGT | Combined cycle gas turbine |
| CCS | Carbon capture and sequestration |
| CPUC | California Public Utilities Commission |
| CT | Combustion turbine |
| DSM | Demand side management |
| DSR | Demand side resources |
| ECW | Energy Center of Wisconsin |
| EE | Energy efficiency |
| EERS | Energy efficiency resource standard |
| EPRI | Electric Power Research Institute |
| FEAST | Frontier Economic Analysis Screening Tool |
| FERC | Federal Energy Regulatory Commission |
| FPL | Florida Power and Light |
| GAAP | Generally Accepted Accounting Principles |
| GWh | Gigawatt-hour |
| IGCC | Integrated gasification combined cycle |
| IOUCC | Indiana Office of Utility Consumer Counselor |
| IRP | Integrated resource plan |
| kW | Kilowatt |
| kWh | Kilowatt-hour |
| LBNL | Lawrence Berkeley National Laboratory |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NAPEE | National Action Plan for Energy Efficiency |
| NCSEA | North Carolina Sustainable Energy Association |
| NCUC | North Carolina Utilities Commission |
| NMPRC | New Mexico Public Regulation Commission |
| NPC | Nevada Power Corporation |
| O&M | Operations and maintenance |
| OCC | Ohio Consumer Council |
| PA | Program administrator |
| PNM | PNM Resources |
| PUCO | Public Utilities Commission of Ohio |
| RAP | Regulatory Assistance Project |
| ROE | Return on equity |
| RPC | Revenue-per-customer |
| RPS | Renewable portfolio standard |
| SACE | Southern Alliance to Conserve Energy |
| SCE | Southern California Edison |
| SFV | Straight Fixed Variable retail rate design |
| SPP | Sierra Pacific Power |
| SWEEP | Southwest Energy Efficiency Project |

| | |
|---|---|
| T&D | Transmission and distribution |
| TRC | Total resource cost |
| UBM | Utility Build Moratorium |
| U.S. | United States |
| $MM | Million dollars |
| $B | Billion dollars |

## Executive Summary

Many state regulatory commissions and policymakers want utilities to aggressively pursue energy efficiency as a strategy to mitigate demand and energy growth, diversify the resource mix, and provide an alternative to building new, costly generation. However, as the National Action Plan for Energy Efficiency (NAPEE 2007) points out, many utilities continue to shy away from aggressively expanding their energy efficiency efforts when their shareholder's fundamental financial interests are placed at risk by doing so. Thus, there is increased interest in developing effective ratemaking and policy approaches that address utility disincentives to pursue energy efficiency or lack of incentives for more aggressive energy efficiency efforts.

New regulatory initiatives to promote increased utility energy efficiency efforts also affect the interests of consumers. Ratepayers and their advocates are concerned with issues of fairness, impacts on rates, and total consumer costs. From the perspective of energy efficiency advocates, the quid pro quo for utility shareholder incentives is the obligation to acquire all, or nearly all, achievable cost-effective energy efficiency. A key issue for state regulators and policymakers is how to maximize the cost-effective energy efficiency savings attained while achieving an equitable sharing of benefits, costs and risks among the various stakeholders.

In this study, we modeled a prototypical vertically-integrated electric investor-owned utility in the southwestern US that is considering implementing several energy efficiency portfolios.[1] We analyze the impact of these energy efficiency portfolios on utility shareholders and ratepayers as well as the incremental effect on each party when lost fixed cost recovery and/or utility shareholder incentive mechanisms are implemented. A primary goal of our quantitative modeling is to provide regulators and policymakers with an analytic framework and tools that assess the financial impacts of alternative incentive approaches on utility shareholders and customers if energy efficiency is implemented under various utility operating, cost, and supply conditions.

We used and adapted a spreadsheet-based financial model (the Benefits Calculator) which was developed originally as a tool to support the National Action Plan for Energy Efficiency (NAPEE).[2] The major steps in our analysis are displayed graphically in Figure ES- 1. Two main inputs are required: (1) characterization of the utility which includes its initial financial and physical market position, a forecast of the utility's future sales, peak demand, and resource strategy to meet projected growth; and (2) characterization of the Demand-Side Resource (DSR) portfolio – projected electricity and demand savings, costs and economic lifetime of a portfolio of energy efficiency (and/or demand response) programs that the utility is planning or considering implementing during the analysis period. The Benefits Calculator also estimates total resource costs and benefits of the DSR portfolio using a forecast of avoided capacity and energy costs. The Benefits Calculator then uses inputs provided in the Utility Characterization to produce a "business-as usual" base case as well as alternative scenarios that include energy

[1] Our analysis does not focus on or directly address distribution-only electric utilities, natural gas utilities, and non-utility third-party energy efficiency program administrators (see section 4 for brief discussion of alternatives to utility program administration).
[2] Michelle Chait of Energy and Environmental Economics (E3), is one of the developers of the original NAPEE Benefits Calculator and is a member of the team that prepared this study.

efficiency resources, including the corresponding utility financial budgets required in each case. If a decoupling and/or a shareholder incentive mechanism are instituted, the Benefits Calculator model readjusts the utility's revenue requirement and retail rates accordingly. Finally, for each scenario, the Benefits Calculator produces several metrics that provides insights on how energy efficiency resources, decoupling and/or a shareholder incentive mechanism impacts utility shareholders (e.g. overall earnings, return on equity), ratepayers (e.g., average customer bills and rates) and society (e.g. net resource benefits).

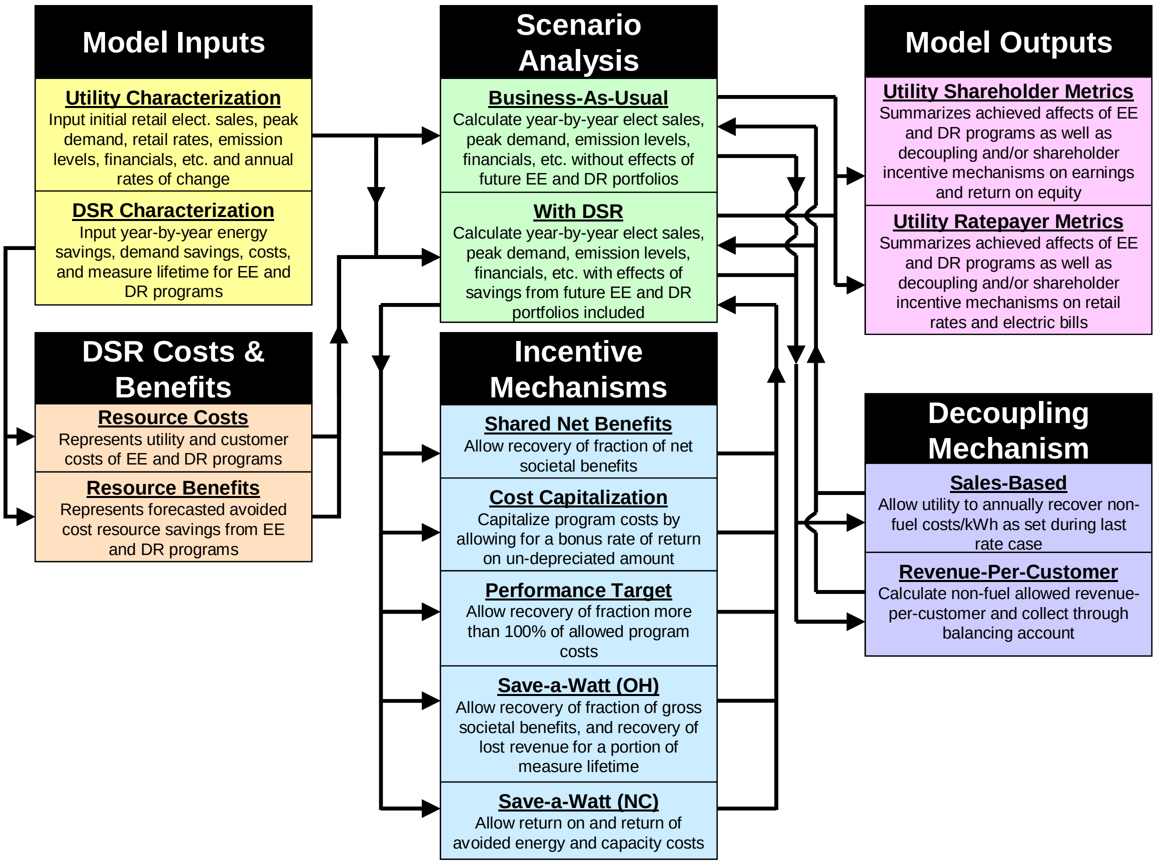



**Figure ES- 1. Flowchart for quantitative analysis of EE incentive mechanisms at prototypical utility**

We modeled a revenue-per-customer full-decoupling mechanism and five different shareholder incentive mechanisms that reward the utility for successfully implementing their energy efficiency portfolio. Three shareholder incentive mechanisms (Performance Target, Cost Capitalization, and Shared Net Benefits) have been implemented at a number of utilities over the last two decades. These three incentive mechanisms were modeled separately with and without the decoupling mechanism. Two shareholder incentive mechanisms have been proposed by Duke Energy and are more comprehensive in nature, combining several different objectives into a single mechanism. The specific mechanisms that were analyzed are: [3]

[3] For each incentive mechanism, the utility's expected earnings are represented on an after-tax basis. Thus, ratepayers are obliged to pay an incentive mechanism to the utility that is grossed-up for the assumed 38% tax liability faced by the utility (e.g., local, state and federal government taxes).

- **Revenue-per-customer decoupling:** This mechanism fully decouples utility sales from non-fuel revenues. The actual allowed non-fuel revenue collected by the utility is the product of the average non-fuel revenue requirement per customer at the time of the last rate case and the current number of customers being served. The total non-fuel revenue collected by the utility increases as the number of customers being served changes. A balancing account is used to ensure ratepayers are either debited or credited for under- or over-collection of the authorized non-fuel revenue requirement. A full decoupling mechanism, such as this one, mitigates the potential for lost profit from any under-recovery of fixed costs through a reduction in retail sales between rate cases.
- **Performance Target**: The utility receives a bonus of an additional 10% of program administration and measure incentive costs for achieving program performance goals. Program costs are explicitly recovered in the period expended through a rider.
- **Cost Capitalization**: The utility capitalizes energy efficiency program administration and measure incentive costs over the first five years of the installed measures' lifetime and is granted the authority to increase its authorized ROE (10.75%) for such investments by 500 basis points.
- **Shared Net Benefits**: The utility retains a pre-determined share (15%) of the net resource benefits (i.e. avoided energy and capacity cost benefits minus utility program costs and installed costs of the energy efficiency measures) from the portfolio of energy efficiency programs. Program costs are explicitly recovered through a rider.
- **Save-a-Watt NC**: The utility capitalizes and collects revenues that are set at 90% of the present value of the stream of total avoided cost savings realized over the lifetime of the installed energy efficiency measures. Given the potential revenue stream, under this proposal, the utility waives the right to collect its program costs and any associated lost earnings from reduced sales volume.[4]
- **Save-a-Watt OH**: The utility retains 50% of the present value of the gross benefits from the portfolio of energy efficiency programs. Program costs are to be covered by this payment. An explicit "lost revenue" component is also included that allows the utility to recover the first three-years of savings from each year's implemented measures or up until the time of the next rate case, whichever comes first, valued at the then existing average retail rate (excluding fuel).[5] Duke Energy also agreed to an earnings cap on the contribution made by the incentive mechanism, although the lost revenue component is not included in the earnings cap.

### Prototypical Southwest Utility: Physical and Financial Characteristics and Resource Need

We reviewed the physical and financial characteristics of a number of utilities in the southwestern United States and created a prototypical southwest utility for this study. Many

[4] Duke Energy Carolina originally proposed Save-A-Watt in May 2007 to the North Carolina Utility Commission, and subsequently filed a similar proposal in South Carolina and Indiana. Program costs are not explicitly recovered and this mechanism also covers any loss of profit due to a reduction in sales. See Appendix C for a more detailed description of our modeling of Save-A-Watt (NC) in the Benefits Calculator.

[5] Duke Energy Ohio filed a revised Save-A-Watt proposal in Ohio on July 31, 2008, after settling on a similar version of the Save-a-Watt design with the Indiana Office of Utility Consumer Counselor (IOUCC). Lost revenues associated with the successful implementation of energy efficiency are directly accounted for and recovered as a *separate* component of this mechanism. See Appendix D for more detailed description of our modeling of Save-A-Watt (OH) proposal in the Benefits Calculator.

utilities in this region have experienced very high load growth over the last decade. In their most recent resource plans, utilities forecast significant growth in peak demand and sales and a need for new generation resources and additional transmission and distribution system investments. Given this situation, energy efficiency has the potential to become an increasingly important resource that can help mitigate projected load growth and possibly defer (or avoid) the need for new resources.

As shown in Figure ES- 2, our prototypical southwest utility has first-year (2008) annual retail sales of 25,000 GWh, an initial peak demand of ~5,700 MW, which produces a 50% load factor.[6] Sales are forecasted to grow at a compound annual rate of 2.8%, while peak demand is expected to increase at a slightly faster rate (2.9%). These load growth and peak demand forecasts represents our "business-as-usual" scenario if energy efficiency is not implemented (BAU No EE case).

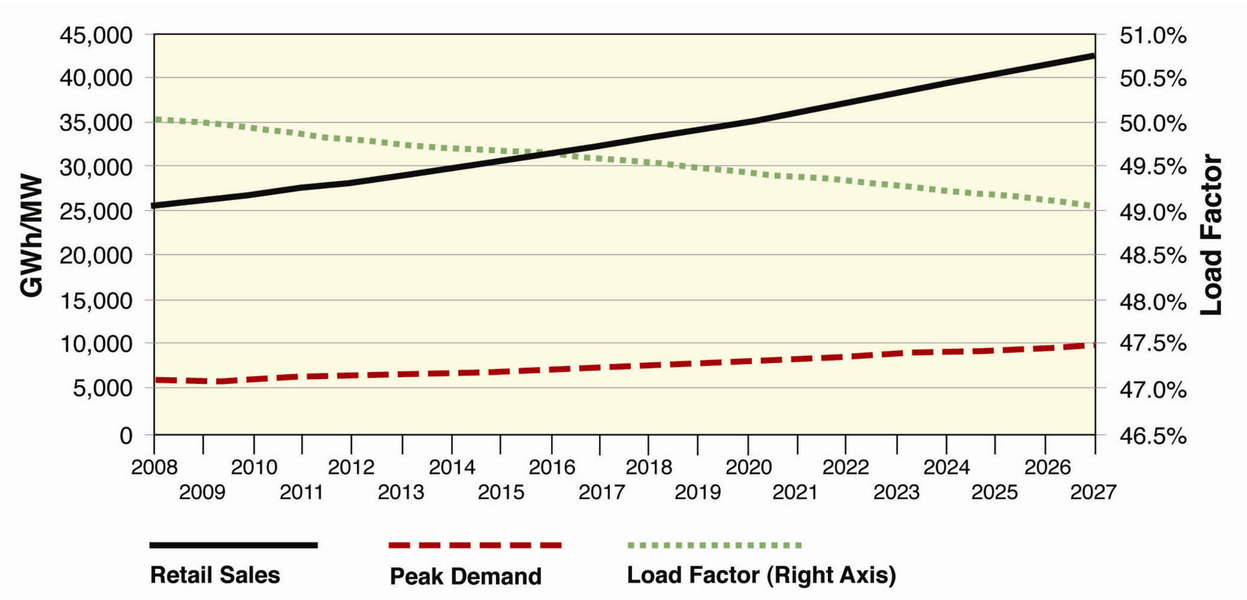



**Figure ES- 2. Forecasted retail sales, peak demand and load factor for prototypical Southwest utility: Business-as-usual No EE case**

The rapid growth in sales and peak demand requires our prototypical utility to aggressively build new generation plant, bringing a new facility on-line roughly every 2.5 years for the duration of the 20 year analysis period (see Figure ES- 3). To finance these plants, the utility uses an equal mix of debt and equity at a cost of 6.60% for debt and an authorized ROE of 10.75%.

[6] See Appendix A for more information on the approach used to develop our prototypical southwest utility. We relied heavily upon publicly available data (e.g., annual reports, 10-K, FERC Form 1, integrated resource plans) predominantly from Arizona Public Service and Nevada Power.

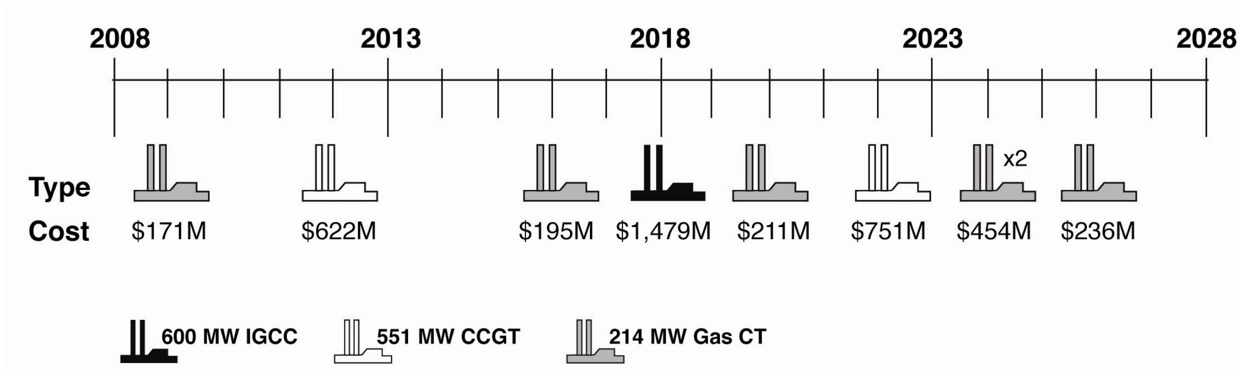



**Figure ES- 3. Generation expansion plan for prototypical Southwest utility: Business-as-usual No EE Case**

Overall, growth in non-fuel costs outpace growth in collected revenues between rate cases from increased sales by well over a 2:1 margin in nearly all utility budget categories (see Table ES-1).[7] Because costs are increasing more rapidly than revenue growth in the "business as usual" case (without energy efficiency), the prototypical utility experiences sizable earnings erosion between rate cases and is unable to achieve its authorized return on equity (ROE) in non-rate case years. To mitigate this detrimental financial impact, we assume that the utility files a rate case every other year (using a current test year methodology).[8] Under these assumptions, this prototypical southwestern utility has an all-in average retail rate of 9.1 ¢/kWh in 2008, which increases to 18.9 ¢/kWh by 2027. In the business-as-usual case (without energy efficiency), the utility's average return on equity is 10.43%, which is 32 basis points below its authorized level.

**Table ES- 1. Prototypical Southwest utility (Business-as-usual No EE case): Major budget expenditures and projected growth**

| Utility Budget Category | 2008 Level ($B) | 2017 Level ($B) | 2027 Level ($B) | Annual Growth Rate (%) |
|---|---|---|---|---|
| T&D Capital Expenditure | $0.3 | $0.5 | $0.7 | 5.0% |
| Ratebase | $4.3 | $6.7 | $11.1 | 5.1% |
| Operations and Maintenance | $0.4 | $0.8 | $2.0 | 8.8% |
| Fuel & Purchased Power | $1.2 | $2.3 | $4.2 | 6.7% |
| Annual Revenue Requirement | $2.3 | $4.2 | $8.1 | 6.9% |
| *All-In Retail Rate* | *9.1 ¢/kWh* | *13.1 ¢/kWh* | *18.9 ¢/kWh* | *3.9%* |

[7] Projections of future utility costs (relative to sales growth) are based on the recent historical experience of several southwestern utilities as reported in Annual Reports and FERC Form 1 data.
[8] This frequency of general rate case filings is not without precedent. Arizona Public Service has filed rate cases in three of the last five years (i.e., 2004, 2006 and 2008).

## Alternative Energy Efficiency Portfolios

Our prototypical southwest utility is considering implementing three energy efficiency portfolios over a 10 year time horizon, partly in response to initiatives by state regulators who want utilities to more aggressively pursue cost-effective energy efficiency resources (see Table ES- 2):[9]

- Moderate EE Portfolio that achieves a 0.5%/year incremental reduction in annual retail sales after two years and maintains this level of incremental energy savings each year for the next eight years;
- Significant EE Portfolio that achieves a 1.0%/year incremental reduction in annual retail sales after three years and maintains this level of incremental energy savings each year for the next seven years; and
- Aggressive EE Portfolio that achieves a 2.0%/year incremental reduction in annual retail sales after five years and maintains this level of incremental energy savings each year for the next five years.

The measures and programs included in the various EE portfolios are designed to achieve the desired electricity savings goals and also reduce peak period sales. We defined the peak period as 8 AM – 10 PM weekdays, and assumed that about 70% of the electricity savings occur in the peak period. Each portfolio of energy efficiency programs has a weighted-average measure lifetime of 11 years. The energy efficiency portfolios produce peak demand savings over the 10 year time horizon that ranges between 226 MW for the Moderate EE portfolio and 743 MW for the Aggressive EE portfolio. The total resource costs range between 2.5 and 4.0 cents per lifetime kWh for the Moderate and Aggressive EE portfolios, which is much lower than the costs of new supply-side alternatives being considered by the utility.

**Table ES- 2. Key features and impacts of alternative energy efficiency portfolios**

| | | | Lifetime Impacts | | | | |
|---|---|---|---|---|---|---|---|
| Energy Efficiency Portfolio | Target % Reduction in Incr. Retail Sales | Ramp-Up Period (Years) | Peak Period Savings (GWh) | Off-Peak Period Savings ( GWh) | Peak Demand Savings (Max MW) | Program Admin. Costs (¢/Lifetime kWh) | Total Resource Costs (¢/Lifetime kWh) |
| Moderate | 0.5%/Year | 2 | 10,452 | 4,479 | 226 | 1.6 | 2.6 |
| Significant | 1.0%/Year | 3 | 19,433 | 8,328 | 421 | 1.8 | 3.0 |
| Aggressive | 2.0%/Year | 5 | 34,314 | 14,706 | 743 | 2.7 | 4.0 |

[9] Some utilities in the Southwest are currently achieving the savings levels in the Moderate EE portfolio and are ramping up toward the savings goals included in the Significant EE portfolio. Several states (e.g. Connecticut, California, Illinois, Massachusetts, New York, and Wisconsin) have recently adopted long-term savings goals that are comparable to the Aggressive EE portfolio goals.

## Key Findings and Conclusions

*1. Aggressive and sustained energy efficiency efforts can produce significant resource benefits at relatively low cost to society and utility customers. However, aggressive and sustained energy efficiency efforts will adversely impact utility shareholder interests by increasing the risk of lost earnings between rate cases and decreasing the available earnings opportunities over time.*

The net resource benefits to customers if the utility successfully implements the moderate EE portfolio are ~$400M while net resource benefits increase to $860M if the utility implements the Aggressive EE portfolio. These energy efficiency portfolios are all very cost effective, producing benefit/cost ratios ranging from 1.7 to 2.6, making them attractive resources from a societal perspective. Ratepayers also would realize a sizable reduction in their aggregate bills as the utility produces and purchases less electricity and defers the need for future supply-side investments. Yet, these investments would have otherwise generated additional earnings for the utility. By replacing them with (EE) investments that by themselves provide no contribution to a utility's bottom line, we found that the utility's earnings decrease by roughly $70M to $110M over the planning horizon and actual achieved ROE drops by 4 and 11 basis points for the Moderate and Aggressive EE portfolios respectively, compared to its ROE of 10.43% in the business-as-usual (BAU) No EE case (see Table ES- 3).

**Table ES- 3. Benefits to Customers vs. Business Reality of Energy Efficiency to the Utility**

| Energy Efficiency Portfolio | Total Resource Benefits ($B) | Total Resource Costs ($B) | Net Resource Benefits ($B) | Benefit Cost Ratio | Customer Bill Savings ($B) | Achieved After-Tax ROE |
|---|---|---|---|---|---|---|
| None | N/A | N/A | N/A | N/A | N/A | 10.43% |
| Moderate | $0.67 | $0.26 | $0.41 | 2.6 | $1.10 | 10.39% |
| Significant | $1.22 | $0.55 | $0.67 | 2.2 | $1.69 | 10.36% |
| Aggressive | $2.06 | $1.20 | $0.86 | 1.7 | $2.37 | 10.32% |

*2. Introducing a decoupling mechanism removes a short-run financial disincentive to energy efficiency by improving the ability of a utility to earn its authorized return between rate cases. Shareholder incentive mechanisms can improve the utility's longer-term business case for aggressive and sustained energy efficiency when success is measured on the basis of ROE rather than the absolute level of earnings.*

The introduction of a revenue-per-customer decoupling mechanism fully offsets the decrease in ROE that occurs if the utility implements any of the EE portfolios. With a revenue-per-customer decoupling mechanism, the ROE is 10.43% for each EE portfolio, which is comparable to the utility's ROE in the BAU No EE case (see Figure ES- 4).[10] Not surprisingly, the utility's ROE

[10] With costs still growing faster annually than the number of customers, the revenue-per-customer decoupling mechanism is unable to collect enough from each customer between rate cases to allow the utility to increase earnings up to its authorized ROE. We assumed that the sales growth rate is equal to the customer growth rate; this means that electricity use per customer is neither increasing nor decreasing over time. The consequence of this

increases if the utility successfully implements its EE portfolios under a shareholder incentive mechanism. Our results suggest that as the level of savings grows from energy efficiency (i.e. from Moderate to Aggressive EE portfolio), the greater is the increase in ROE. For example, if the utility implements the Moderate EE portfolio, the utility's ROE increases by 3-4 basis points with our Performance Target and Cost Capitalization incentive and by 13 basis points with the Shared Net Benefits mechanism. The ROE increases by 15 to 23 basis points if the utility successfully implements the Aggressive EE portfolio. Given our assumed design features, Shared Net Benefits yields the greatest increase in ROE for the utility (see Figure ES- 4).

However, if we focus on the utility's after-tax earnings, the picture looks quite different. Utility earnings for any EE portfolio and shareholder incentive mechanism, except Shared Net Benefits, are $2M to $60M lower compared to the business-as-usual No EE case (see Figure ES- 4). These results illustrate an important tension for utility shareholders/managers. Conceptually, finance theory suggests that the preferred metric to assess the value of alternative resource options to utility shareholders is their incremental impact to net earnings per share (EPS) on a risk-adjusted basis. We did not explicitly model EPS impacts because it would have required assumptions regarding the timing and number of equity shares issued. We have therefore measured the impact of incentive mechanisms on shareholder value using earnings and ROE metrics. For shareholder incentive mechanisms that do not require the utility to issue new equity shares (i.e., all incentive mechanisms except Cost Capitalization), incentive mechanisms increase earnings and ROE relative to the case where no financial incentive is provided. The Cost Capitalization mechanism increases rate base equity; the ROE in this case reflects this higher equity balance.

assumption is that when a revenue-per-customer decoupling mechanism is applied, the growth in collected revenue between rate cases is the same as the growth in collected revenue that occurs in the "business-as-usual" No EE case. Given the frequency of rate cases, the application of the RPC decoupling mechanism when EE is implemented results in the utility achieving the same return on equity as when no energy efficiency was undertaken.

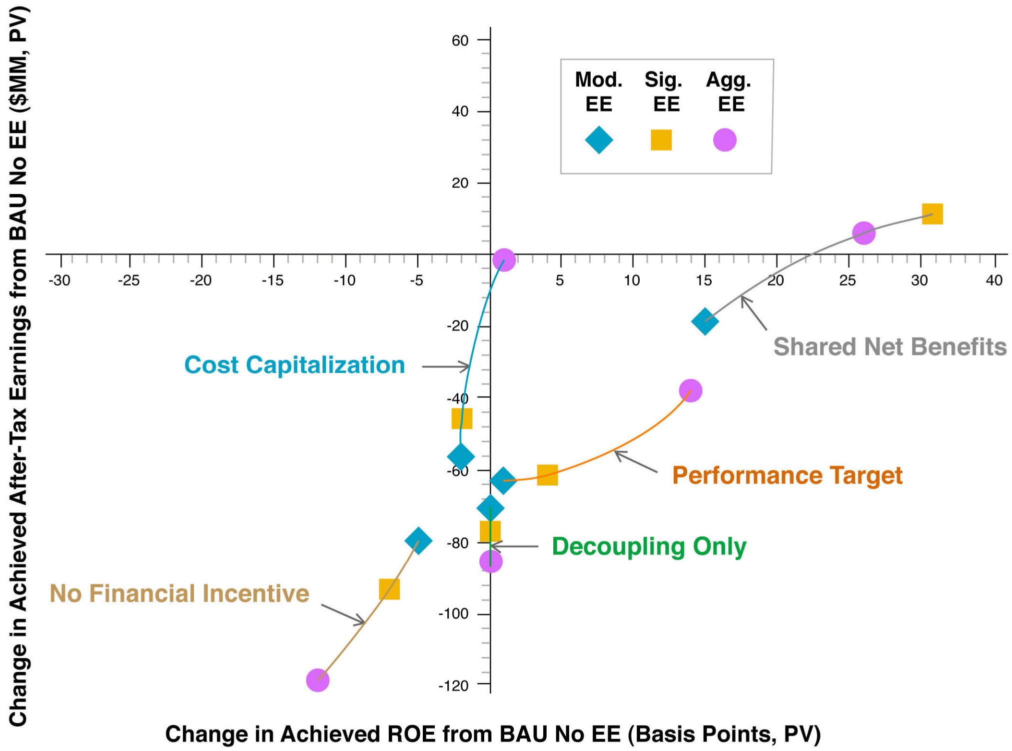



**Figure ES- 4. Achieved After-Tax Earnings and Return on Equity (ROE): Impact of energy efficiency portfolios, decoupling and shareholder incentives**

*3. Average utility bills would decrease by 3-6% if the utility successfully implements the energy efficiency portfolios in conjunction with decoupling or these shareholder incentive mechanisms compared to the "business-as-usual" No EE case.*

Customers are interested in the magnitude of bill savings from energy efficiency and potential rate impacts. With an EE portfolio included in the utility's resource mix, ratepayers capture the reduction in fuel and purchased power costs immediately through a fuel adjustment clause. Moreover, due to the higher cost of supply-side resources (see Table ES- 1), the deferral value of energy efficiency increases with larger and deeper savings levels. The frequency of rate cases (i.e., biennial) allows consumers to capture the majority of these non-fuel cost savings (between 76% and 88%). Aggregate bill savings for all customers in the form of a lower revenue requirement range between $1.0B for the Moderate EE portfolio to $2.32B for the Aggressive EE portfolio over the 20-year planning horizon (see Figure ES- 5). On a percentage basis, ratepayer bills as a whole drop by ~3-6%, even with a decoupling or a shareholder incentive applied.

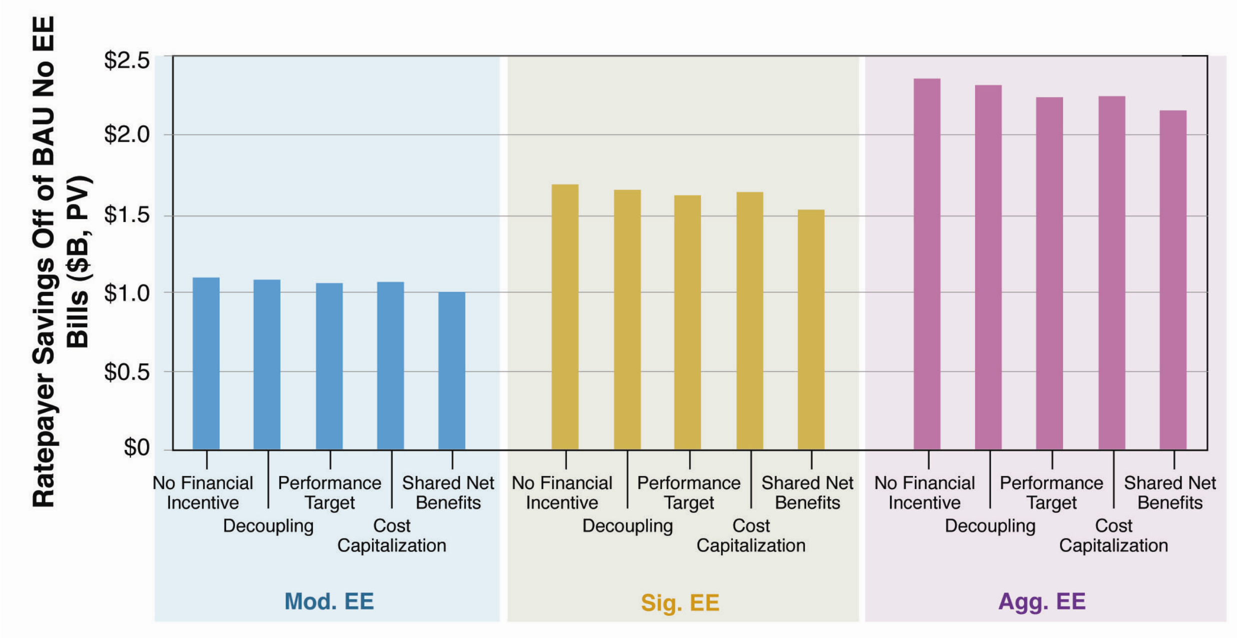



**Figure ES- 5. Ratepayer bill savings: Impact of energy efficiency portfolios, decoupling and shareholder incentives**

*4. The three EE portfolios have a modest effect on average retail rates over the 20-year planning horizon, even with the added cost of a decoupling or shareholder incentive.*

Without decoupling or shareholder incentives, retail rates actually drop by 0.1 mills/kWh for the Moderate EE portfolio and increase only minimally by 1.0 to 3.5 mills/kWh under the Significant and Aggressive savings goals (see Figure ES- 6). If the utility implements the Significant EE portfolio and decoupling or incentive mechanisms are adopted, average retail rates increase by 1.0 to 1.4 mills/kWh compared to the Business As Usual No EE case. Average rates increase by 3.6-4.2 mills/kWh if decoupling or incentive mechanisms are available in the Aggressive EE portfolio. On a percentage basis, average retail rates are about 0.07% to 2.2% higher in 2027 (the end of the planning horizon) if the utility implements the Significant or Aggressive EE portfolio with shareholder incentives compared to rates in the Business-As-Usual No EE case.

Why are average retail rates higher if the utility implements the Significant or Aggressive EE portfolio compared to the Business-As-Usual No EE case? To analyze rate impacts, we examined changes in the utility's cost of service among the different scenarios. We found that the bulk of the reduction in the utility's cost of service due to energy efficiency comes from reduced generation-related expenses (i.e., savings of between $1.0B to 2.8B for the Moderate or Aggressive EE scenario). T&D-related cost savings are relatively small (~$250M), in part because of our modeling assumption that energy efficiency programs only have a limited ability to defer T&D investments. Thus, retail rates associated with generation costs decrease, but are offset somewhat by the increase in rates to recover energy efficiency program costs. Rates associated with transmission and distribution-related costs also increase for the three EE portfolios because T&D costs must be recovered over a reduced sales base (and because T&D

cost savings from energy efficiency are less than the reduction in consumption associated with energy efficiency). The net impact of these changes to the various rate components results in a modest increase in the all-in retail rate (from 0.1 to ~4 mills/kWh) if the utility implements various EE portfolios with a shareholder incentive and recovers its revenue requirement.[11]

As a practical matter, participants in the utility's energy efficiency program would have lower utility bills as savings from installed measures would more than offset the small increase in rates. Non-participants would see their utility bills increase by <1 to 2%, but over a 10-year period there would be few non-participants, particularly if the utility implements the Significant or Aggressive EE portfolio. In thinking about the modest rate impact if the utility implements the Significant or Aggressive EE portfolio, it is also important to note that we have assumed that there is no uncertainty in the costs of the supply resources added in the Business-As-Usual (BAU), No EE case. For example, if new supply-side resources cost more than is projected in the utility's BAU resource plan because of cost overruns, this also would put upward pressure on rates in the BAU No Case, which would reduce the likely rate impacts of an EE portfolio.

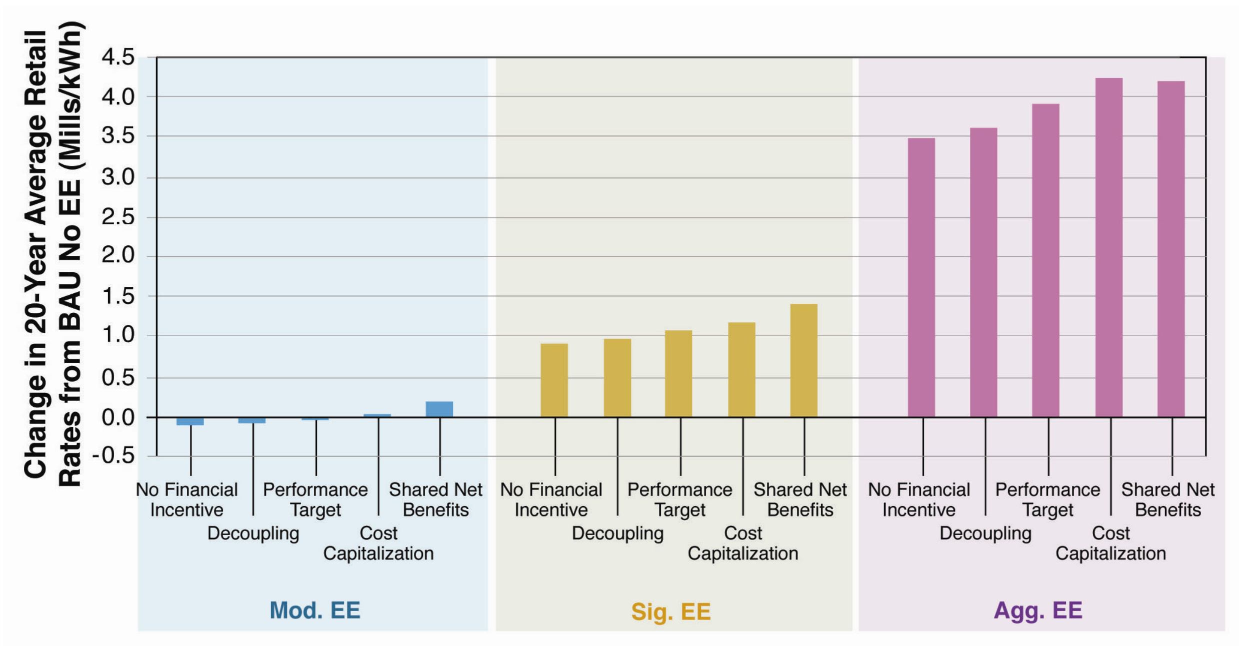



**Figure ES- 6. Retail Rates: Impact of energy efficiency portfolios, decoupling and shareholder incentives**

*5. Combining a decoupling mechanism with a shareholder incentive further improves the business case for energy efficiency for the prototypical utility; alternatively, the proposed Save-A-Watt (NC) mechanism provides the utility with the opportunity for much higher earnings and ROE.*

[11] We portray an all-in retail rate where the entire revenue requirement is collected through volumetric charges. For this reason, the change in retail rates is a function of how the revenue requirement is reduced relative to the reduction in retail sales. If the revenue requirement is falling at a slower rate than sales are dropping, retail rates must increase for the utility to successfully collect its authorized revenue requirement at that level of retail sales.

We also analyzed the impacts on earnings, customer bills and rates, and net resource benefits if a Performance Target, Cost Capitalization or Shared Net Benefits shareholder incentive is implemented in conjunction with an RPC decoupling mechanism or alternatively, if one of the Save-a-Watt approaches proposed by Duke Energy is implemented. The Save-a-Watt mechanisms (as filed separately in North Carolina and Ohio by Duke Energy) provide for some internal recovery of lost revenue (either explicitly in Ohio or implicitly in North Carolina) along with an opportunity for additional earnings. We highlight several key results:

- The utility's ROE improves if it implements any of the EE portfolios and has both a decoupling and shareholder incentive mechanism compared to the BAU No EE case (see Figure ES- 7). For any EE portfolio, the Cost Capitalization mechanism generally provides the utility with the smallest increase in ROE compared to other incentive mechanisms because the utility must issue additional equity to cover the capitalization of program costs. The combination of decouping and shareholder incentives can create conditions for utility shareholders and managers to pursue energy efficiency as a "profit center" for this prototypical Southwest utility.
- Under all three EE cases, Save-A-Watt (NC) as proposed by Duke Carolina provides the prototypical utility with an opportunity for significantly higher earnings and ROE than any of the other approaches that combine decoupling and a shareholder incentive mechanism. For example, Save-A-Watt (NC) increases earnings between $194 and $538 million and ROE by 86 to 205 basis points for the Moderate and Aggressive EE portfolios respectively compared to the BAU No EE case, which is roughly six times higher than other combined decoupling/incentive mechanisms in our analysis. Save-A-Watt (Ohio) as proposed by Duke Ohio provides returns to shareholders that are comparable to the other three combined incentive/decoupling mechanisms (see Figure ES- 8).
- The lost margin recovery component of the Save-A-Watt (OH) mechanism contributes somewhat more to earnings than does the RPC decoupling mechanism when applied jointly with a shareholder incentive mechanism (see Figure ES- 9). For example, if the utility implements the Aggressive EE portfolio, 35% of the earnings contribution comes from the Save-A-Watt (OH) lost margin recovery component, rather than the shareholder incentive. In contrast, the RPC decoupling mechanism provides about 22-29% of the increased earnings that arise from Aggressive energy efficiency portfolio investments when implemented in conjunction with a Performance Target, Cost Capitalization, and Shared Net Benefits incentive.
- Depending on the EE portfolio, average retail rates are about 1-4 mills/kWh higher over the 20 year period compared to the BAU No EE case for all incentive mechanisms except Save-a-Watt NC, where rates are 9.0 mills/kWh higher in the Aggressive EE portfolio (see Figure ES- 9).

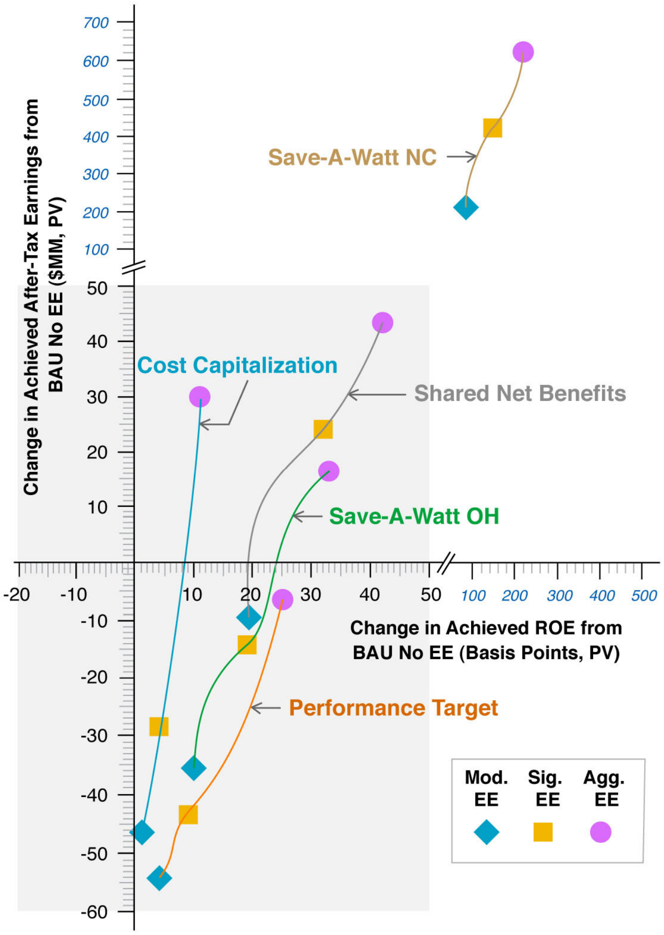



**Figure ES- 7. Earnings and return on equity (ROE): Combined effect of fixed cost recovery and shareholder incentive mechanisms**

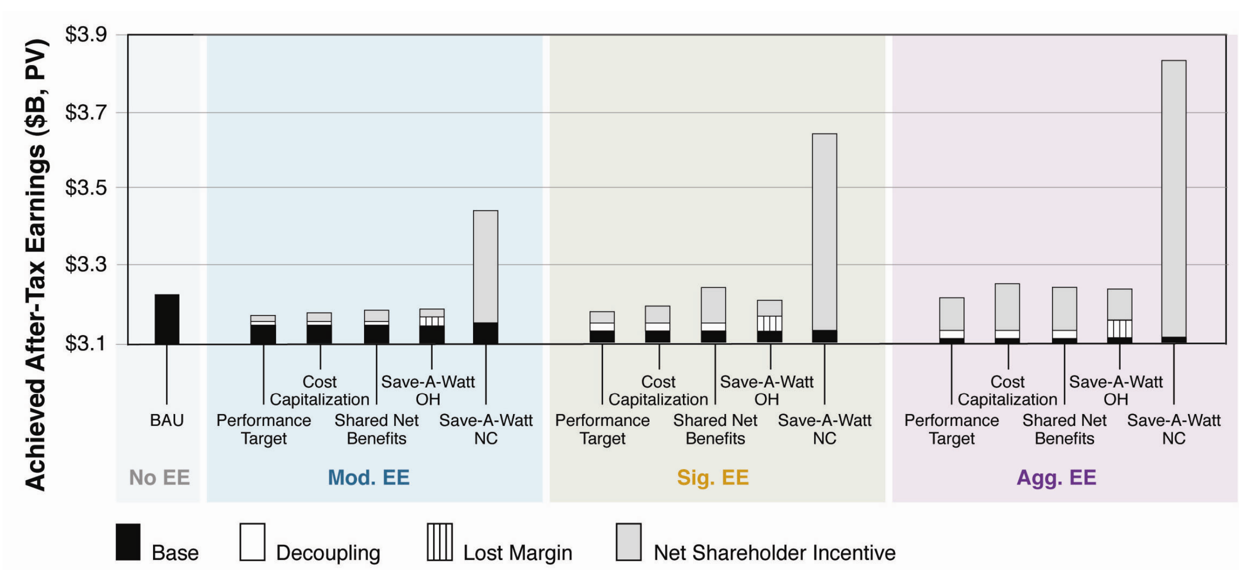



**Figure ES- 8. After-tax earnings: Combined effect of fixed cost recovery and shareholder incentive mechanisms**

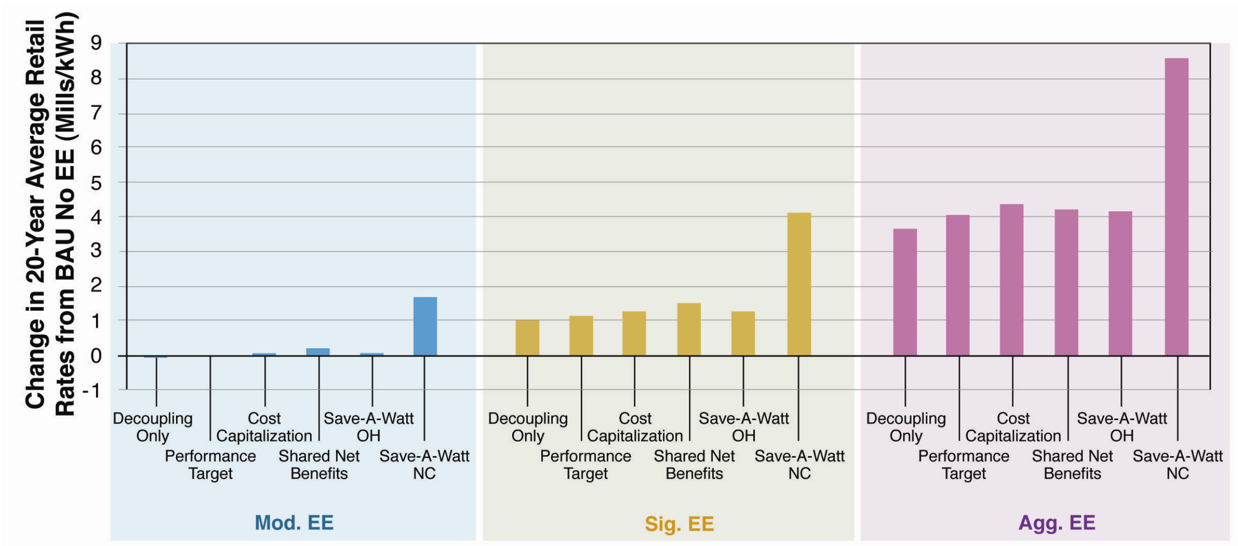



**Figure ES- 9. Retail Rates: Combined effect of fixed cost recovery and shareholder incentive mechanisms**

*6. Ratepayers receive 70-90% of the net benefits from EE portfolios that include the costs of decoupling and one of three shareholder incentive mechanisms (Performance Target, Cost Capitalization, Shared Net Benefits); ratepayer's share of net benefits is much lower under the Save-A-Watt (NC) proposal.*

In assessing the relative merits of decoupling and shareholder incentive proposals, state regulators may consider equity and fairness issues such as the share of net resource benefits provided to customers vs. shareholders and the potential impact of an incentive mechanism on the overall level of EE program costs. Fairness may be achieved when the cost of a shareholder incentive mechanism is set at a level that is adequate but not excessive to mitigate barriers to achieving those increased benefits. In Table ES- 4, we show the five incentive mechanisms expressed in terms of the combined cost of the lost revenue recovery and shareholder incentive mechanisms as a percent of program cost and ratepayer share of net resource benefits for the three EE portfolios. We would highlight the following results.

- The ratepayer share of net benefits is relatively high (70-90%) for our Performance Target, Cost Capitalization, Shared Net Benefits, and Save-A-Watt (OH) mechanisms under any of the EE portfolios.

- The Save-a-Watt (NC) mechanism provides a substantial amount of the net resource benefits to shareholders. Under the proposed Save-a-Watt (NC) mechanism, there are no net resource benefits given the proposed design (i.e., the utility receives 90% of avoided cost benefits) and our assumptions about customer cost contribution for energy efficiency measures.[12]

[12] Net total resource benefits are negative for the proposed Save-A-Watt (NC) mechanism because it provides the utility with 90% of the avoided cost benefits in its revenue requirement which when combined with our EE program

- In terms of impact on overall EE program costs, the incentive mechanisms that are tied to underlying program budgets (i.e., Performance Target and Cost Capitalization) represent about 21% to 26% of program costs across the three EE portfolios. Under the Shared Net Benefits mechanism, the larger the net resource benefits, the larger the incentive (in total dollars) given to shareholders, although the incentive is smaller relative to EE program budgets. The utility's share of net benefits represents a significant share of program costs (58-70%) for the Moderate and Significant EE portfolios, and would increase program costs by about 33% for the Aggressive EE portfolio (as the benefit/cost ratio drops due to more expensive measures necessary to achieve deeper savings levels). The Save-A-Watt (NC) mechanism, as designed, would provide an earnings opportunity for the utility that represents a very high share of program costs. For example, earnings exceed program costs by 33% to 171% for our prototypical southwest utility under the Save-A-Watt (NC) proposal.

**Table ES- 4. Metrics used to assess the cost and fairness of jointly implementing fixed cost recovery and utility shareholder incentives**

| | Ratepayer Share of Net Resource Benefits | | | Fixed Cost Recovery and Pre-Tax Incentive as % of Program Cost | | |
|---|---|---|---|---|---|---|
| **Incentive Mechanism** | **Mod. EE** | **Sig. EE** | **Agg. EE** | **Mod. EE** | **Sig. EE** | **Agg. EE** |
| Performance Target | 90% | 88% | 79% | 26% | 25% | 23% |
| Cost Capitalization | 90% | 89% | 80% | 24% | 23% | 21% |
| Shared Net Benefits | 72% | 72% | 70% | 70% | 58% | 33% |
| Save-a-Watt OH | 81% | 79% | 72% | 49% | 43% | 30% |
| Save-a-Watt NC | -8% | -14% | -23% | 271% | 232% | 133% |

*7. The design of a decoupling and shareholder incentive mechanism (e.g. earnings basis) can significantly influence its value and perceived costs and risks to utility shareholders and ratepayers. In assessing the relative merits of proposed incentive mechanisms, PUCs should consider and analyze quantitative metrics that reflect the interests and concerns of both shareholders and ratepayers (e.g., ratepayer share of net resource benefits, impact on EE program costs, target increase in ROE that rewards superior performance in achieving EE goals). This approach can provide insights on the design of incentive mechanisms that create a sustainable business model for the utility to aggressively pursue energy efficiency while effectively balancing ratepayer interests.*

Up to this point, we have defined the earnings basis for each shareholder incentive mechanism at levels that are representative of their application in one or more states (e.g. California, Nevada, Massachusetts, Connecticut) or proposed by a utility (in the case of Duke's Save-A-Watt mechanisms). Our analysis suggests that results for each incentive mechanism are strongly

design assumption that customers pay ~50% of incremental measure costs yield negative net resource benefits from a societal perspective.

influenced by our choices with respect to earnings basis (e.g. the utility's share of net benefits, % of program costs awarded for achieving a performance target, equity kicker for Cost Capitalization).

An alternative approach would be for a regulatory commission to indicate its willingness to consider shareholder incentive mechanism proposals that provide utility shareholders with the opportunity to earn a specified, targeted increase in the utility's after-tax ROE if the utility successfully achieves its energy efficiency savings goals while retaining a minimum specified share of net resource benefits for ratepayers. This approach could lead a regulatory commission to make an implicit determination on the issue of "how much is enough" to motivate utility management to achieve superior performance in administering a portfolio of energy efficiency programs. An important by-product of this approach is that it potentially sets an upper limit on the financial (and rate) impacts of a shareholder incentive mechanism, which may be important to certain stakeholders. For simplicity, we illustrate this approach excluding the potential impacts of a decoupling mechanism on the design (and earnings basis) of a shareholder incentive mechanism.[13]

Assume that the regulatory commission's policy goals are to capture a significant portion of the resource benefits of energy efficiency for ratepayers while developing a sustainable business model for the utility to aggressively pursue energy efficiency. To illustrate this concept, we assume that a PUC decides that an energy efficiency incentive mechanism should provide at least 80% of the net resource benefits to ratepayers while providing the utility with an opportunity to increase its after-tax ROE by a maximum of 20 basis points compared to the BAU No EE case. The tradeoff between ratepayer and shareholder benefits associated with the Performance Target, Shared Net Benefits and Save-a-Watt (NC) mechanisms are shown in Figure ES- 10.[14] We offer the following observations:

- In the Moderate EE portfolio, the utility can not achieve a 20 basis point improvement in its ROE without receiving a larger share of the net resource benefits (i.e., 30% of net resource benefits). This would result in ratepayers receiving less than the 80% target share of net resource benefits set forth by the PUC. If the 80% share of net benefits for ratepayers is considered as a binding constraint to obtain the support of customer groups, then the utility would not be eligible for a shareholder incentive in the Moderate EE case. Alternatively, the utility may propose a lower ROE target to partially address these concerns (e.g. increase ROE by 5 basis points for achieving Moderate savings goals), while still providing an improved business case for EE at this lower level of savings.

[13] A PUC could also decide to institute a decoupling mechanism and also offer the utility an opportunity to increase earnings by a targeted amount (e.g., 10 or 20 basis points); this would change (and reduce) the earnings basis for each shareholder incentive accordingly.

[14] Cost Capitalization requires additional equity to be issued; thus, the utility's achieved return on equity will be diluted for the same contribution to earnings as are provided by other shareholder incentive mechanisms. This aspect of the Cost Capitalization mechanism makes comparisons across different shareholder incentive mechanisms with respect to improvements in ROE more challenging (see Appendix F). We also exclude the Save-a-Watt Ohio mechanism from this aspect of the analysis because the mechanism has several different design features (i.e., share of gross resource benefits, lost fixed cost recovery time period) that make construction of comparable mechanisms to Performance Target, Shared Net Benefits, and Save-a-Watt NC challenging.

- If the utility achieves the savings targets in the Significant and Aggressive EE portfolios, a mechanism can be constructed whereby ratepayers and shareholders both receive their "fair share" of the benefits. If the utility achieves the desired 1% reduction in annual retail sales in the Significant EE portfolio, then a mechanism can be designed such that the utility's ROE increases by 20 basis points while ratepayers retain 80% of the net resource benefits. If the utility achieves the Aggressive EE portfolio savings target, then ratepayers could receive an additional 2% of net resource benefits (i.e. 82%), while still providing the utility with a 20 basis point improvement in its after-tax ROE from a shareholder incentive mechanism.

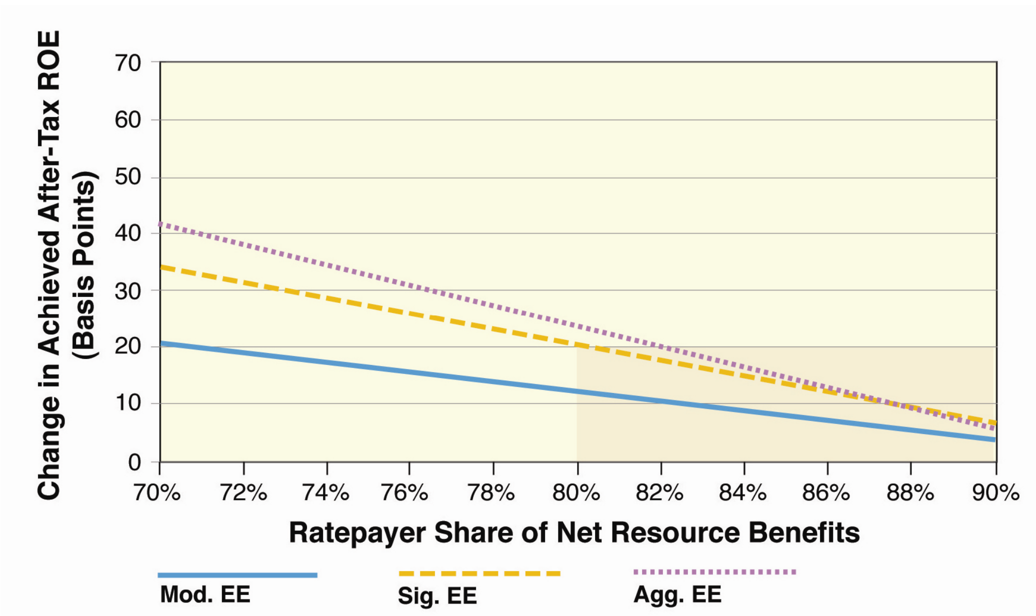



**Figure ES- 10. Tradeoff between Ratepayer and Shareholder Benefits for Alternative EE Portfolios with a Performance Target, Shared Net Benefits, and Save-A-Watt (NC) mechanism**

- Not surprisingly, the earnings basis for several of the incentive mechanisms that meet our PUC's illustrative policy goals criteria are substantively different than the original designs (see Table ES- 5). For the Shared Net Benefits mechanism, the utility's share of net resource benefits (which is the earnings basis) does not change much between the Significant and Aggressive EE portfolios (11-12%) and turns out to be roughly comparable to the original design of our Shared Net Benefits mechanism (15%).[15] In contrast, the earnings basis for the Performance Target and Save-A-Watt mechanism change significantly if savings targets are increased from 1% to 2% and the utility's target increase in ROE is set at a maximum of 20 basis points.

[15] Because the net resource benefits are effectively monetized and converted into increased earnings for the utility via the shareholder incentive, there are now three parties that must share the net resource benefits: shareholders, ratepayers and the government by way of taxes. This explains why the earnings basis for this mechanism when added to the share of net resource benefits retained by ratepayers is less than 100%.

- These results also suggest that an earnings basis of ~40% of avoided costs for Save-A-Watt (NC) for our prototypical utility would put it on a more comparable basis with the other three incentive mechanisms in terms of a 20 basis point target ROE bonus (and the ratepayer share of net resource benefits), which is substantially lower than Duke Carolina's proposed earnings basis (i.e., 85%-90% of avoided costs).

**Table ES- 5. Key Metrics and Design Criteria for Desired Incentive Mechanism**

| | Ratepayer Share of Net Resource Benefits | Change in After-Tax ROE from BAU No EE (Basis Points) | Incentive as % of Total EE Program Costs | Shareholder Incentive Mechanism Earnings Basis Level | | |
|---|---|---|---|---|---|---|
| | | | | **Performance Target** | **Shared Net Benefits** | **Save-a-Watt NC (Revised)** |
| *Earnings Basis* | | | | *% of Program Cost* | *Utility % of Net Benefits* | *% of Avoided Costs* |
| *Original Design* | | | | *10.0%* | *15.0%* | *90.0%* |
| Mod. EE | N/A | N/A | N/A | N/A | N/A | N/A |
| Sig. EE | 80% | 20 | 41% | 25.3% | 12.4% | 36.1% |
| Agg. EE | 82% | 20 | 19% | 12.1% | 11.2% | 43.7% |

Quantitative analysis of alternative incentive mechanisms under different EE scenarios, including consideration of metrics that provide insights on equity and fairness issues (e.g., contribution to shareholder wealth, sharing of net resource benefits between ratepayers and shareholders and the percentage mark-up that the additional earnings provide in excess of program costs) are useful tools that can facilitate prudent design of shareholder incentive mechanisms and can help align the interests of various parties in promoting energy efficiency.

## 1. Introduction

Many state regulatory commissions and policymakers want utilities to aggressively pursue energy efficiency as a strategy to mitigate demand and energy growth, diversify the resource mix, and provide an alternative to building new, costly generation. Renewed interest in energy efficiency as a resource is driven by recent increases in fuel and capital construction costs for electricity generation, heightened awareness of the detrimental environmental impacts from the energy sector, and recognition that energy efficiency can reduce total costs of energy services for customers and mitigate the effects of rising energy prices.

Many states have already embarked or are actively considering embarking on a path that would greatly increase funding for energy efficiency programs over the next several years. Estimated energy efficiency spending in 2007 was $2.6 billion compared to less than $1 billion in 1998 (York and Kushler 2006; CEE 2007). A number of states (e.g., California, Rhode Island, Connecticut, Minnesota, Massachusetts, and Vermont) have passed legislation directing utilities to acquire all available cost-effective energy efficiency. Some of the leading states, which generally achieved annual energy efficiency program energy savings equivalent to about 1% of retail energy sales, are proposing to increase annual energy savings targets to about 2% of retail energy sales. Yet, as the National Action Plan for Energy Efficiency (NAPEE 2007) points out, utilities continue to shy away from aggressively expanding their energy efficiency efforts when their own fundamental financial interests are placed at risk by doing so. Therefore, it should not be surprising that with the prospect of substantially increased utility expenditures for energy efficiency, there is increased interest in developing effective ratemaking and policy approaches that address utility disincentives to pursue energy efficiency or lack of incentives for more aggressive energy efficiency efforts.

While some utilities seem willing to undertake a large and increasing commitment to energy efficiency, they seek to mitigate the risk of diminished earnings and/or the opportunity to earn a profit in return for those aggressive energy efficiency efforts. Large-scale energy efficiency efforts can significantly increase a utility's financial risk by creating a greater deviation between a utility's estimated test year sales and its actual sales for that period. The more that some of a utility's short-run fixed costs (including profit margin) are included in volumetric prices ($/kWh and $/kW), the more significant the likelihood that the utility could under-recover its authorized return on equity. Moreover, utility costs associated with administering and delivering energy efficiency programs are typically treated as an expense. Thus, energy efficiency programs provide no return to utility shareholders and if successful could defer or avoid capital investment on which a return could have been earned. These factors underlie the recent discussion of the need for new regulatory strategies to facilitate more aggressive utility energy efficiency efforts: specifically, the potential form of an effective incentive or reward framework for utilities that also overcomes disincentives that exist under traditional regulation.

New regulatory initiatives to promote increased utility energy efficiency efforts will also affect the interests of consumers. Consumers and their advocates are concerned with issues of fairness, impacts on rates, total consumer costs and ensuring that "real" cost-effective savings are being attained. From the perspective of energy efficiency advocates, the quid pro quo for utility shareholder incentives for increased energy efficiency efforts is the obligation to acquire all, or nearly all, achievable cost-effective energy efficiency and support for related energy efficiency initiatives (e.g., improved building codes and appliance/equipment standards). A key issue for state regulators and policymakers that want to overcome utility disincentives to increased energy efficiency efforts is how to best accommodate all of the various interests in a manner that maximizes the cost-effective energy efficiency savings attained while achieving an equitable sharing of benefits, costs and risks.

There have been a number of previous studies that have explored how to better align utility financial interests with energy efficiency goals, often from a theoretical perspective (e.g., Moskovitz et al. 1992; Stoft, et al.1995; Golove and Eto 1996; and Moskovitz 2000). Other studies have focused on descriptive comparisons of alternative regulatory mechanisms to incent utilities to aggressively pursue energy efficiency as a resource (Eto et al. 1994; Harrington et al. 1994; Hansen 2007; and Jensen 2007). This report is specifically intended to provide regulators, policymakers and advocates who are interested in more aggressive utility energy efficiency efforts with improved information to quantitatively compare the financial effects of alternative shareholder incentive mechanisms on different stakeholders (utility, consumers and the public) under diverse utility operating, cost and supply conditions.

In general, quantitative analysis of incentive structures for energy efficiency is rarely found in the literature. Our analysis runs deeper than Price et al. (2007), although both utilize the same basic financial model, the National Action Plan for Energy Efficiency's (NAPEE) Benefits Calculator.[16] Price et al. (2007) constructed several different characterizations of utilities revolving around load growth assumptions; distribution vs. vertically integrated utilities; and publicly owned vs. investor-owned, to illustrate how the Benefits Calculator could be used to quantify the financial impact from utility, customer and societal perspectives. The analysis presented in this report focuses exclusively on ***a prototypical vertically-integrated electric investor-owned utility in the southwest***. We explicitly model a comprehensive set of incentive mechanisms, including Duke Energy's proposed Save-A-Watt, and additional mechanisms that address under-recovery of fixed costs (e.g. revenue per customer decoupling and "lost revenue" mechanisms). Our impacts analysis is also more comprehensive from both a physical standpoint (i.e., alternative supply expansion plans, varying load and cost growth assumptions) as well as from a financial standpoint (i.e., varying initial retail rate levels, cost growth). To accommodate these sensitivities, LBNL made significant modifications to the NAPEE Benefits Calculator, which allowed us to model more varied shareholder incentive and decoupling mechanisms; annual demand-side resource program savings and cost levels; and the ability to capture changes in the utility cost structure (i.e., capital expenditure, O&M, fuel and purchased power, etc.) based on the size and type of major generation additions. This updated and expanded financial tool is able to provide relative comparisons of the financial consequences of the most prevalent incentive mechanisms for energy efficiency that have been adopted or proposed in the US.

Improved quantitative modeling can provide some insights into key issues surrounding business models for achieving increased energy efficiency. However, quantitative modeling alone cannot address behavioral issues that result when economic incentives are used to affect behavior. This study does not assess how utility management will actually respond to an incentive mechanism, or how utility management may respond differentially to alternative incentive mechanisms with

[16] Michelle Chait, of Energy and Environmental Economics (E3), is one of the developers of the original NAPEE Benefits Calculator and is a member of the team that prepared this study.

varying designs. For example, what level of financial incentive is actually sufficient for a utility to aggressively pursue all or most cost-effective energy efficiency savings opportunities? What factors influence utility management's interest in business models that encourage pursuit of all cost-effective energy efficiency?

We also do not evaluate the relative effectiveness of incentive mechanisms to motivate utilities with regard to other positive "behavior" that may be of concern to regulators and stakeholders (e.g., pursue energy efficiency as cost-efficiently as possible, ensure that lost opportunities are not created in the process). We also do not analyze the extent to which these incentive mechanisms depend upon design parameters that are more/less uncertain to forecast or difficult/easy to verify, which can also affect the actual allocation of benefits, costs, and risks between shareholders and ratepayers. We also do not reflect the collateral impacts of decoupling on issues such as weather risk or economic cycle risk and the related reductions in the utility's cost of capital. Finally, it should be noted that we do not perform a comparative analysis of the relative merits of utility vs. non-utility administration of energy efficiency programs; see Eto et al 1998 and Blumstein et al 1998 for a more detailed discussion of these issues.

The remainder of this report is organized as follows. In Chapter 2, we discuss issues concerning expanding energy efficiency efforts under a regulatory framework. In Chapter 3, we describe the approach and results of the quantitative analysis of a prototypical utility implementing three alternative energy efficiency portfolios with varying savings targets under different physical and financial conditions. Finally, in Chapter 4, we discuss several key policy issues related to the need for and design of ratemaking and shareholder incentive mechanisms in order to frame the conclusions of our quantitative analysis in a broader context.

## 2. Utility's Commitment to Energy Efficiency

Like any profit-oriented business, utility expenditures that improve the ability to earn an acceptable profit will be favored, while those that increase the risk of loss or diminish the opportunity to profit will tend to be disfavored. As described in Jensen (2007), there are three major financial hurdles that tend to shape a regulated electric (and gas) utilities view toward the aggressive implementation of large-scale energy efficiency programs:

- The expectation of timely recovery of energy efficiency program costs;
- The potential risk for the reduction in profits between rate cases if sales volume is lowered; and
- The potential to avoid or defer a supply-side capital investment that is generally allowed to earn a rate of return in favor of energy efficiency expenditures for which there may not be an earnings opportunity.

This chapter reviews these financial effects and discusses options available to state regulators interested in increasing a utility's interest in and/or commitment to achieving energy efficiency savings goals. Several of these options are then selected to provide the framework for the quantitative analysis set forth in this report. Readers that are familiar with these issues at a conceptual level may choose to move directly to Chapter 3.

### 2.1 Disincentives to energy efficiency associated with traditional regulatory framework

#### 2.1.1 Program Cost Recovery

Typically, an investor-owned utility must demonstrate to its state PUC that costs previously incurred or expected to occur in the near future should be recovered from its customers.[17] Costs that are incurred but then later disallowed by regulators have a direct and measurable negative impact on utility earnings.

The uncertainty associated with the timing of cost recovery may also influence a utility's expenditure decisions (Jensen, 2007). When a utility incurs an expense which it expects to later recover from ratepayers it, in effect, creates a receivable account on its balance sheet which is typically referred to as a regulatory asset. The investment community will tend to discount the value of this asset if it becomes large relative to the size of the company because of concerns over whether it will, in fact, be allowed by regulators to be recovered from ratepayers.

Energy efficiency programs may require substantial up-front investment costs (e.g., staffing requirements, program development costs, marketing material, and back-office systems) as well as on-going program costs. This exposes the utility to risk concerning cost recovery, especially when the recovery of costs made in one year are amortized for recovery over a substantial

[17] Regulators have three basic reasons for disallowing costs under traditional regulation: (1) if a PUC believes that such costs should not be borne by ratepayers, because they neither directly nor indirectly benefit from the expenditure, (2) the size and/or scope of the expenditure was not, justified leading PUCs to recommend partial disallowances of those costs, (3) a PUC may question the judgment associated with the utility's decision to incur the cost and used as grounds for disallowance (i.e. the prudence standard) (Jensen, 2007).

number of future years (WECC 1993). Disallowance of these costs, like other utility costs, can directly impact earnings. When these "regulatory assets" reach a significant level, the Wall Street rating agencies may impute additional debt to the utility's capital structure, which can increase the utility's overall cost of capital. In practice, nearly all utilities that implement energy efficiency programs have been allowed by their PUC to treat energy efficiency costs as a current expense, for which cost recovery contemporaneous to the spending occurs, which effectively mitigates this risk.

### 2.1.2 Fixed Cost Recovery

Traditional regulation does not set a utility's revenues, only its prices. Customer rates are typically set to recover a utility's test year revenue requirement, which includes fixed and variable costs; rates remain in effect until the next rate case absent other ratemaking treatment.[18] Most utilities recover the bulk of their short-term fixed costs (including the utility's authorized profit margin) through volumetric rates. If actual sales are lower than estimated, then the utility will receive less revenue than expected and not earn its authorized return (unless it is able to offset these uncollected revenues with lower costs). Similarly, if actual sales increase more than estimated sales and actual costs do not increase faster than revenues collected, a utility will over-earn its authorized return. Thus, a utility has a strong financial incentive to increase sales between rate cases, and conversely, an incentive to protect against decreases in sales. This is commonly referred to as the "through-put incentive" (Shirley et al 2008). Utilities face the prospect of decreased earnings if sales are reduced by energy efficiency and costs do not contract as much as revenues.

### 2.1.3 Loss of Financial Opportunities and Growth

Under traditional cost of service regulation, a utility only has the opportunity to earn a return on capital investments such as power plants and transmission/distribution systems. Large scale energy efficiency programs have the potential to defer the need for additional investment in utility infrastructure (e.g., generation, and in some cases, transmission and distribution). These capital expenditures, if allowed, are placed into a utility's rate base where the investment is authorized to earn a rate of return on the portion financed through equity. By deferring or avoiding the opportunity to construct facilities, the pursuit of energy efficiency can engender the perception that this will diminish the utility's financial strength (WECC 1993).

Utilities focused on total earnings, rather than rates of return typically do not pursue aggressive energy efficiency efforts, even if program cost and fixed cost recovery issues are addressed, because the expected earnings from building a power plant will be substantially larger than those derived from energy efficiency programs. Clearly, utility managers will consider issues related to comparative levels of risk and opportunity costs associated with earnings from alternative investments (e.g., ability to obtain regulatory approvals and support for power plant construction by utility, risk of cost over-runs, probability of disallowances). Senior utility managers may perceive that the reward of greater earnings from a large construction project is greater than the

[18] For a large number of utilities, there are some cost categories, like fuel and purchased power costs, that are passed through to customers on a periodic or more frequent basis. Fuel adjustment clauses are one example of a regulatory mechanism that has been developed to mitigate risks associated with potential volatility in fuel costs.

risks of under-earning and should, therefore, be pursued. An additional factor, sometimes suggested, that could reinforce the utility choice of wanting to build a plant is that the compensation package for senior utility managers may be based on the firm's total achieved level of earnings (as opposed to its rate of return), thus any action that reduces rate base will likely be disfavored.

## 2.2 Providing incentives for energy efficiency

In this section, we describe several approaches that have been used to better align public and utility interests to support aggressive energy efficiency efforts and discuss those specific approaches chosen to be modeled in this report.

### 2.2.1 Recovery of Program Costs

State regulators have developed a number of approaches to address utility concerns regarding timely recovery of prudent utility energy efficiency program expenditures. For example, inclusion of estimated energy efficiency program costs in the test year revenue requirement is a common means. Some commissions also allow a deferral account to allow a utility the opportunity to spend more funds than authorized in the test year and to recover those expenditures in a subsequent rate proceeding. This allows the utility to avoid interrupting or halting approved energy efficiency program efforts that have gained momentum in the market. Even where program costs are recovered over time, statutory provisions can be used to mitigate the risk of non-recovery. In practice, effective means have been developed to substantially mitigate risks associated with cost recovery. For purposes of this study, we have assumed that energy efficiency program costs would be allowed to be recovered as prudent and reasonable costs.

### 2.2.2 Recovery of Fixed Costs

Three approaches have been suggested to remove utility disincentives to support investments in energy efficiency: (1) a straight fixed variable (SFV) retail rate design, (2) a decoupling mechanism and (3) a net lost revenue recovery mechanism.

#### *2.2.2.1 Straight Fixed-Variable Rate Design*

The Straight Fixed-Variable Rate Design has been proposed by a number of gas utilities and imposes a fixed charge to customers which is designed to recover all "fixed" costs (Shirley et al. 2008).[19] This has the effect of stabilizing the revenues of a utility because changes in consumption by customers have much less impact on the overall amount of their bill. This rate design partially decouples a utility's revenues from its sales; however, it also has the effect of weakening the link between customers' total utility bills and their actual consumption levels, which reduces the price signal for individual consumers to conserve and undertake energy efficiency investments. Within a customer class, this type of rate design adversely impacts those

[19] SFV rate designs proposed by utilities are often designed to recover "fixed" costs and may go beyond accounting definitions to include return on equity, most distribution and operation expenses, and federal and state income taxes. Current rate designs (particularly those for residential customers) typically collect most fixed costs from customers via volumetric charges.

customers that consume less energy compared to customers that use more electricity (given that fixed charges account for a greater share of the total bill) (Shirley et al. 2008).

#### *2.2.2.2 Lost Revenue Recovery Mechanism*

Another alternative is to compensate the utility for the “net lost revenues” associated with the implementation of energy efficiency measures. With this approach, the utility is only compensated for the sales margin and incremental loss of revenue estimated to occur as a result of utility energy efficiency programs (Shirley et al 2008). A Net Lost Revenue Recovery mechanism focuses exclusively on the measurable and verifiable impact that the portfolio of energy efficiency measures has on the collection of revenue when sales are successfully reduced. Critics note that a “lost revenue” recovery mechanism does not affect the throughput incentive: if the utility’s short-run marginal cost is lower than its retail rate, it still profits when sales increase” (Shirley et al 2008). Moreover, “lost revenue” mechanisms can be time consuming, costly and highly contentious to implement when the methodology and its application are debated in front of regulators (Jensen 2007).

#### *2.2.2.3 Decoupling Mechanisms*

A decoupling mechanism renders revenue levels immune to changes in sales by adjusting retail rates either upwards or downwards depending upon how collected revenues associated with the recovery of fixed costs over a certain period compare with those authorized under the decoupling mechanism (Shirley et al. 2008). While traditional regulation holds rates constant between rate cases and allows revenues to change with sales, decoupling hold revenues constant (or subjects them to a formulaic change over time) and allows prices to change with sales. Furthermore, decoupling allows for the retention of volumetric, unit-based pricing structures that reflect the long-term economic costs of serving demand and preserves the linkage between consumers’ energy costs and their levels of consumption (Shirley et al. 2008).

Several approaches to decoupling have been implemented. “Full decoupling” insulates a utility’s revenue collections from any deviation of actual sales from expected sales, without regard for the cause of the deviation. The flat revenue approach of full decoupling, in which total revenues associated with fixed costs are held constant between rate cases, is sometimes termed a revenue cap. An alternative to this method utilizes a revenue-per-customer approach, in which the total allowed revenue changes with the number of customers served, using an average revenue-per-customer value derived from the last rate case. “Partial decoupling” insulates only a portion of the utility’s revenue collections from deviations of actual from expected sales (e.g. variation in sales results in a partial true-up of utility revenues). "Limited decoupling" means that there is some mechanism to isolate specific causes for changes in sales (e.g. weather, savings from EE programs) and either include or exclude them from the utility’s revenue collections.[20]

[20] For example, some states (e.g., Oregon) exclude the effects of weather. Other states may only include savings from utility-sponsored EE programs (similar to a net lost revenue approach).

### 2.2.3 Shareholder Performance Incentives

An energy efficiency incentive mechanism provides a program administrator with an opportunity to earn financial incentives for successful administration and implementation of a portfolio of energy efficiency programs. Over the last two decades, a number of states and utilities have implemented or proposed incentive mechanisms for energy efficiency. In this section, we describe five major types of shareholder incentive mechanisms: performance target, shared savings, cost capitalization and Save-a-Watt, as proposed by Duke Energy Carolina and later Duke Energy Ohio with significant changes. It is important to note that incentive mechanisms are typically more complex in practice than our characterization. For example, a utility's incentive mechanism may include several different types of incentives that are linked to specific performance goals (e.g. annual or lifetime energy savings, net benefits, peak demand savings). Moreover, incentive mechanisms often include various design features, such as minimum performance thresholds in order to be eligible for incentives, an earnings cap, formulas that link incentive amounts to achievement of various performance goals, and penalties for failure to achieve minimum acceptable performance.

#### *2.2.3.1 Performance Target*

Under a performance target incentive mechanism, the utility administrator receives a payment for achieving a specified performance goal, often a savings target. Often, the utility only receives an incentive if it achieves some minimum fraction of the proposed savings target and earnings payments may be linked to specified levels of performance (e.g. performance target payments may increase with verified savings) (Jensen 2007).[21] In some jurisdictions, there is a cap on the level of a performance target incentive, which may be designed to protect ratepayers from excessive payments. Figure 1 provides a simple illustration of a performance target mechanism in which a utility receives a bonus payment (based on actual program costs) if it achieves a 1% reduction in annual retail sales through its energy efficiency programs.

[21] In Connecticut, utilities are eligible for performance target incentives (referred to as "performance management fees") for achieving 70 to 130% of pre-determined goals (such as lifetime energy savings). Utilities can earn 2 to 8% of total energy efficiency program expenditures that depend on achieving goals within the 70-130% goal range.

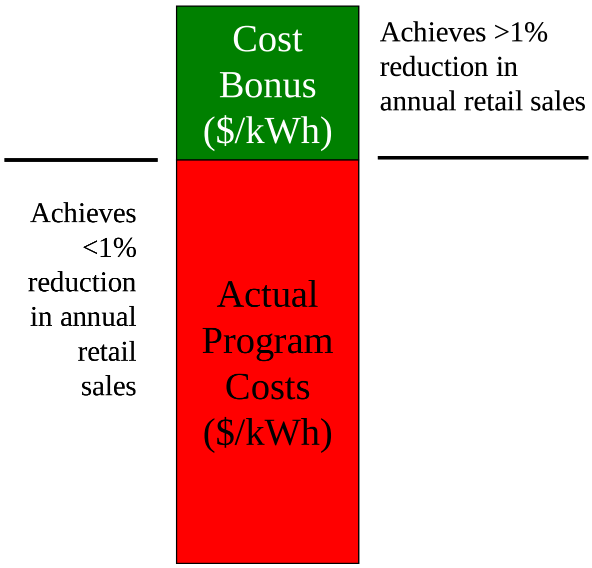


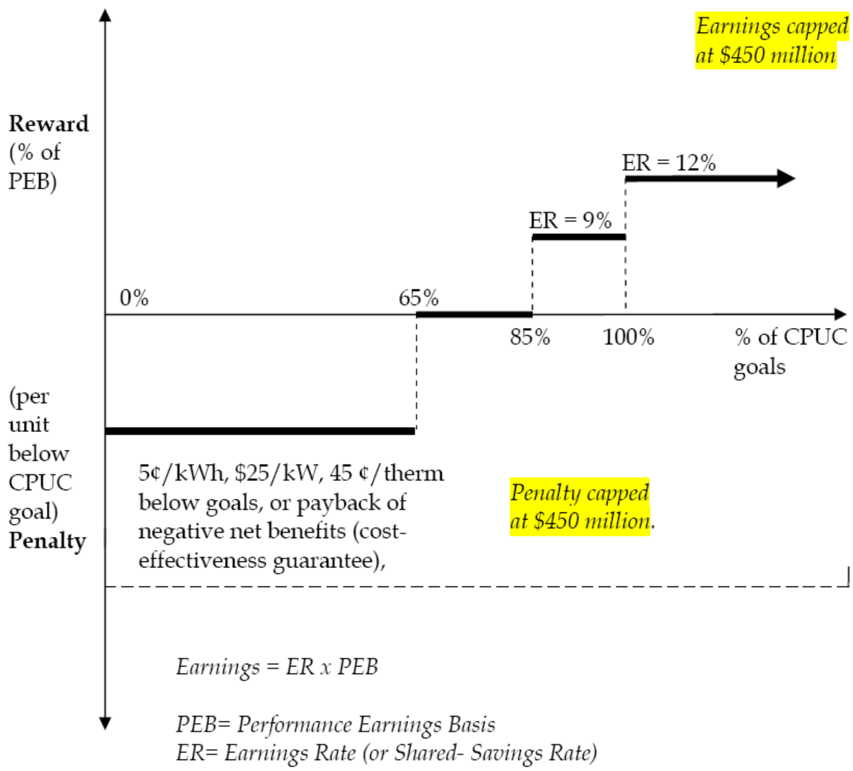

**Figure 1. Illustration of Performance Target shareholder incentive mechanism**

#### *2.2.3.2 Shared Net Benefits*

Another way to reward utilities for aggressively pursuing energy efficiency is to allow them to retain a pre-determined share of the forecasted net resource benefits which occur through successful implementation of energy efficiency programs and measures (Jensen, 2007). Resource benefits are typically derived by multiplying lifetime energy and peak demand savings from installed measures by forecasted current and future avoided energy and generation (and T&D) capacity costs (and possibly environmental externalities). Program costs (or total resource costs) are subtracted to determine net resource benefits. Key design features of a shared net benefits incentive mechanism include the sharing formula for benefits (e.g. % of net benefits retained by the utility), method used to determine avoided cost benefits, whether or not to cap the amount of allowed earnings, minimum performance levels that must be achieved for additional earnings, and extent to which there are penalties if a utility fails to achieve a minimum performance target (Jensen 2007).

The California Public Utility Commission recently revamped its shareholder incentive mechanism, utilizing a shared net benefits approach (CPUC 2007). Figure 2 provides a graphical illustration of the mechanism adopted by the CPUC, which depicts the penalty assessment when performance drops below 65% of CPUC goals for the three year energy efficiency program cycle, payment provision of 9% of verified net benefits if utilities achieve 85% to 100% of verified net benefits goal, with higher sharing rates (12%) for utilities that meet or exceed 100% of the performance earning goals, and a statewide cap on both earnings and penalties of $450 million, respectively.[22]

[22] Penalties are calculated as the greater of a charge per unit (e.g., kWh, kW, or therm) for shortfalls at or below 65 percent of goal or a dollar-for-dollar payback to ratepayers of any negative net benefits (Jensen 2007).




Source: CPUC Decision 07-09-043

**Figure 2. Illustration of a Shared Net Benefits shareholder incentive mechanism**

#### *2.2.3.3 Cost Capitalization*

Under cost capitalization, the utility administers energy efficiency programs and is provided with an opportunity to earn a rate of return on energy efficiency-related investments. Rather than being expensed, authorized EE program administration and measure incentive expenditures are capitalized (i.e. put into rate base) and the utility earns a return in a manner similar to supply-side assets. Several states that allowed ratebasing or capitalization for energy efficiency have offered a bonus (or premium) rate of return on these investments (Jensen 2007). Typically, the investment is amortized over some period of time (e.g., six years, the lifetime of the installed measures), where the un-depreciated asset is allowed to earn a return at the authorized ROE for energy efficiency investments. This mechanism is illustrated in Figure 3, for an energy efficiency program that invests $10M in 2008 that is amortized over a 5 year time period where both debt and equity are used to fund the program.

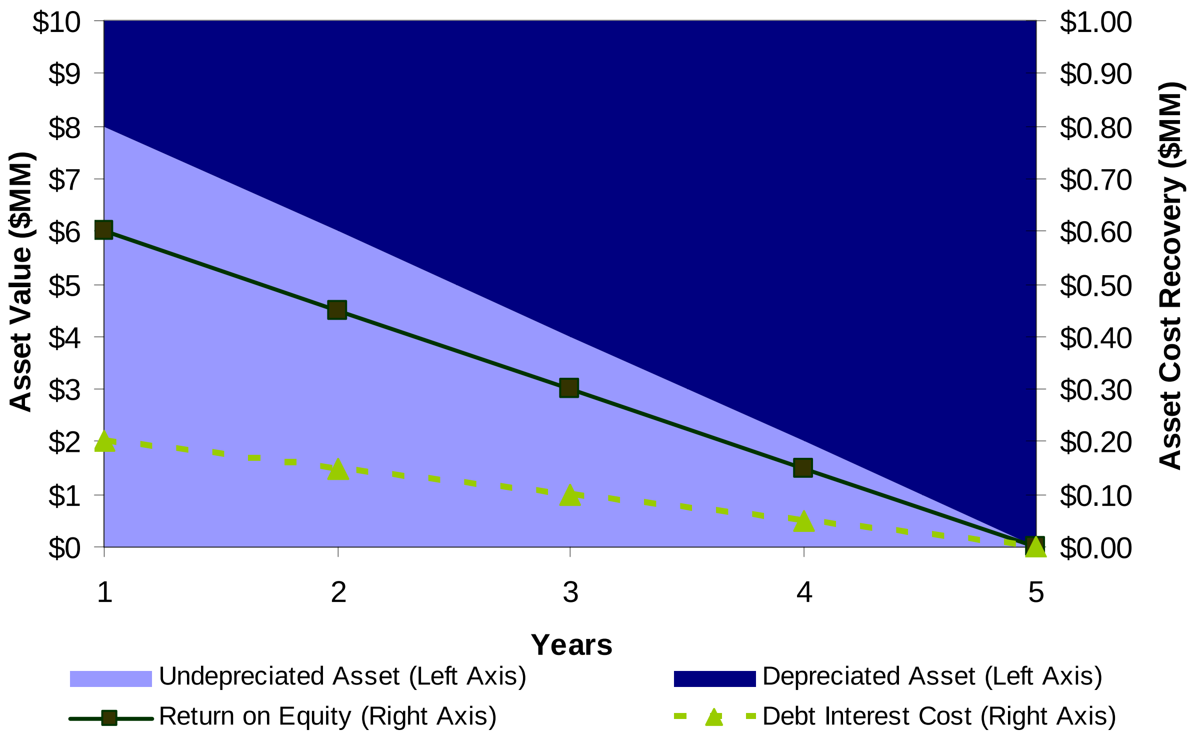



**Figure 3. Illustration of Cost Capitalization shareholder incentive mechanism**

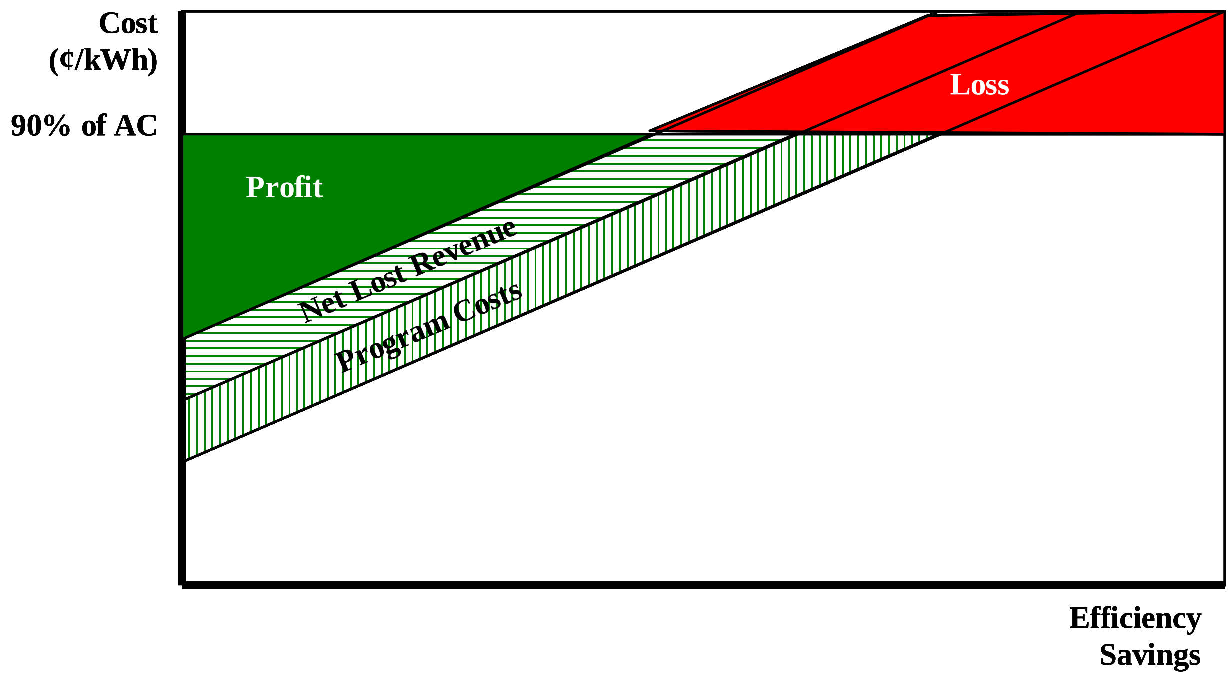
#### *2.2.3.4 Save-a-Watt (North Carolina)*

Duke Energy Carolina filed its demand-side management plan with the North Carolina Utility Commission (NCUC) in the summer of 2007, which included a novel incentive mechanism (Duke 2007). The mechanism (a.k.a. Save-a-Watt) was designed to allow the utility to receive a return on a pre-determined fraction of the total avoided energy and capacity costs for actual savings achieved over the lifetime of the utility's energy efficiency and demand response programs. This value is represented by the avoided investment in energy and capacity.

For measures installed in a given "vintage" year, the annual expenditures avoided for both energy and capacity over the installed measures' expected lifetime (using the "vintage" year's avoided cost forecast) are discounted back to the year they were installed, which serves as the basis for the total avoided investment. Then for each year the measures are still in operation, this avoided investment is depreciated and allowed to earn a return at the utility's after-tax equity-weighted ROE. Each year that new measures are installed, this calculation is repeated with an updated avoided cost forecast.

Program expenditures (i.e. administration and measure incentive costs) to achieve the load and demand savings as well as any lost earnings between rate cases due to a reduction in sales are implicitly covered by the Save-a-Watt revenue requirement. Whatever is left over from the monies collected under Save-a-Watt after paying for program costs and lost earnings would be considered the traditional incentive payment provided to the utility.[23]

Figure 4 provides a graphical depiction of Save-A-Watt (NC) utilizing Duke Carolina's initial request to collect 90% of the avoided costs of energy and capacity. Duke proposes to collect a Save-A-Watt revenue requirement which it will use to offset energy efficiency program costs, any net lost revenues associated with a reduction in sales between rate cases, and provide an opportunity to earn a profit (or be at risk for potential earnings loss).[24] According to Duke, this structure creates an explicit incentive to design and deliver programs efficiently, as doing so will minimize the program costs and maximize the financial incentive received by the company.




Source: Cowart and Prindle 2007.

**Figure 4. Illustration of Duke Energy (NC) Save-a-Watt incentive mechanism**

#### *2.2.3.5 Save-a-Watt (Ohio)*

As part of its required Energy Security Plan, Duke Ohio filed a modified version of the original Save-a-Watt North Carolina mechanism with the Public Utilities Commission of Ohio in July 2008 (Duke 2008a).

Duke Ohio's proposed Save-A-Watt mechanism has several key features. First, Duke proposes to retain a fixed proportion of the gross resource benefits from their portfolio of DSM programs

[23] The other three shareholder incentive mechanisms do not include a component for the recovery of lost earnings from a reduction in sales due to energy efficiency. We account for this issue in section 3.4.2.1

[24] This aspect of the Save-a-Watt incentive mechanism is illustrated in much greater detail in Hornby (2008).

to cover program expenditures and serve as a financial reward for approaching, achieving or surpassing peak demand and retail sales savings goals established by the Ohio legislature.[25] The proportion of gross resource benefits retained by Duke Ohio varies between energy efficiency (i.e., 50%) and demand response (75%).

Second, the net earnings from this component of the Save-a-Watt Ohio mechanism is to be capped based on the achievement of peak demand and/or retail sales savings goals, as a percent of total program expenditures. For example, if Duke Ohio achieves less than 80% of the target savings levels, then earnings from this component of the mechanism are capped at 9% of total program costs. If Duke Ohio achieves between 80% and 104% of the savings goals, then its earnings are capped at 15% of total program expenditures and if Duke exceeds 105% of the sales and peak demand reduction goals, then Duke's earnings are capped at 18% of program costs.

Third, a true-up mechanism that includes the earnings cap will be applied in the year following an independent program evaluation that will be completed after the first three years of the program. The goal of the true-up mechanism is to allow the utility to true-up revenues against deviations between forecasted and actual sales, as well as forecasted and achieved sales and peak demand reductions from implemented EE and DR programs,

Fourth, Duke Ohio proposes an explicit "lost revenue" recovery mechanism that allows it to receive the revenue lost due to the installed energy efficiency and demand response measures, valued at the current year's average retail rate, excluding fuel, for three years or until the next rate case, whichever comes first.[26] The time period over which the utility is allowed to recover "lost revenues" from reduced EE sales turns out to be very important in analyzing impacts on utility shareholder earnings, particularly if there is no requirement for periodic, frequent rate cases.

[25]. Duke Ohio's Save-A-Watt incentive mechanism did not propose a rate of return on and of the avoided energy and capacity investment which was proposed by Duke in North and South Carolina.

[26] In North Carolina, Duke proposes to recover any "lost revenues" due to energy efficiency implicitly through the Save-a-Watt revenue requirement.

## 3. Quantitative Analysis of Energy Efficiency Incentive Mechanisms

In this section, we present a method to quantitatively evaluate the financial impacts of different incentive mechanisms and discuss results for a prototypical utility that is considering implementing various EE portfolios over a 10 year time period. Quantitative financial modeling can help assess the likely impacts of specified regulatory policies and/or utility business decisions under certain identified conditions. In terms of a roadmap, we first provide an overview of the analysis method to be utilized. Then, we describe the key attributes of our prototypical utility, both from a physical as well as financial standpoint, and the incentive and ratemaking mechanisms under consideration to help entice the utility to achieve specified energy efficiency savings targets.[27] Next, we compare and analyze the financial consequences on shareholders and ratepayers of implementing various EE portfolios (Moderate, Significant, Aggressive) in conjunction with the introduction of a decoupling mechanism, or alternative shareholder incentive mechanisms either separately or in combination. Finally, we illustrate a different approach that takes the perspective of a regulatory commission that is interested in providing the utility with an additional earnings opportunity target (i.e., specified increases in their after-tax ROE) for successfully implementing a portfolio of EE programs and also considers the end results that are of most interest to ratepayers (i.e., ratepayer share of net resource benefits and impact on EE program costs).

### 3.1 Overview of Analysis Method

We used and adapted a spreadsheet-based financial model (the Benefits Calculator) which was developed originally as a tool to support the National Action Plan for Energy Efficiency. Our modified version of the Benefits Calculator includes sufficient detail to adequately capture the interaction between changes in sales and a utility's cost and revenue streams.

The basic flow of our analysis is graphically displayed in Figure 5. Two main inputs are required: (1) Utility characterization – a characterization of the initial financial and physical market position of the utility, a forecast of the utility's future sales, peak demand, and resource strategy to meet projected growth; and (2) Demand-Side Resource (DSR) Characterization - a characterization of the portfolio of energy efficiency (and/or demand response) programs that the utility is planning or considering implementing over the analysis period. The DSR characterization is used to develop an overall picture of the total DSR resource costs and benefits using a forecast of avoided capacity and energy costs. The Benefits Calculator then takes these two sets of inputs and derives annual electricity sales and demand for various scenarios (e.g. Business as usual case and scenarios that include energy efficiency resources) and the corresponding utility financial budgets required in these scenarios. If a decoupling and/or a shareholder incentive mechanism are instituted, the Benefits Calculator model readjusts the revenue requirement and the retail rates accordingly to see how the utility's and ratepayers finances are affected. Finally, the Benefits Calculator takes all this physical and financial data to

[27] The specific findings of our analysis are limited to utilities with characteristics similar to those of our prototype utility. In Appendix E, we conducted sensitivity analysis and varied key financial and physical assumptions regarding the prototypical utility to better understand the impacts of energy efficiency on shareholders and customers under these circumstances. We looked at three different scenarios: (1) Low Growth Utility, (2) Utility Build Moratorium, and (3) Higher Cost utility. This was an initial attempt to expand the applicability of our findings to utilities and regions with other characteristics.

produce a series of output metrics that can be used to better understand how energy efficiency, decoupling and/or a shareholder incentive can actually influence the financial health of the utility and its shareholders and ratepayers.

The Benefits Calculator model has the ability to produce both an *a priori* **estimate** of the net resource benefits if the utility successfully implements a portfolio of energy efficiency programs and an *ex post* quantification of the **actual achieved** change in utility customer bills, retail rates, shareholder earnings, and return on equity.[28] Dealing with potential "end effects" issues in a consistent fashion is a key challenge in modeling and estimating net resource benefits and cost savings to the utility. One approach is to limit the study analysis period to capture only those affects associated with the initial installation of energy efficiency measures. However, because the typical practice is to model EE programs offered over a multi-year period, EE measures installed in these programs will reach the end of their economic lifetime in a staggered manner. If EE measures are not replaced with equally energy efficient measures at the end of their useful lifetime, the utility's load and peak demand forecast will increase. Using this modeling approach, utility costs will again appear to increase in order to meet this increased load and demand growth. However, savings from those measures that are still in their initial lifetime continue to provide the utility and its ratepayers with benefits. These two countervailing effects can not be disentangled within the Benefits Calculator. An alternative approach is to assume that program participants will replace installed EE measures at the end of their useful economic lifetime at their own expense or at no additional expense because some fraction of the products have been integrated into building codes and appliance and equipment efficiency standards. In this case, the economic benefits of the initial investment in the measures are continued, but it is impossible to isolate the impact of the initial measures, which the utility can take direct credit for, from those that are replaced by the program participants. Under either approach, the financial analysis of the utility's actual reduction in its costs due to implementing an energy efficiency portfolio will not line up with the forecasted avoided cost benefits because of these terminal effects. The Benefits Calculator model would either under- or over-estimate the benefits relative to the California Standard Practice Manual perspective (CPUC 2001).[29]

[28] Administratively determined avoided energy and capacity costs are typically used to estimate resource benefits in cost-effectiveness screening of EE programs and for incentive mechanisms that are linked to resource benefits (e.g., Shared Net Benefits, Save-A-Watt). These resource benefits are effectively proxies for the *actual* savings that the utility and (and society) experiences from a reduction in sales and peak demand from EE programs These two different methods provides perspective on how accurate administratively-determined avoided cost estimates are relative to an estimate of the utility's actual achieved and realized dollar savings. Unfortunately, such a comparison is not simple to accomplish, even for such a robust financial model as the Benefits Calculator.

[29] This is an important consideration when comparing the achieved benefits to ratepayers and shareholders relative to the forecasted net resource benefits.

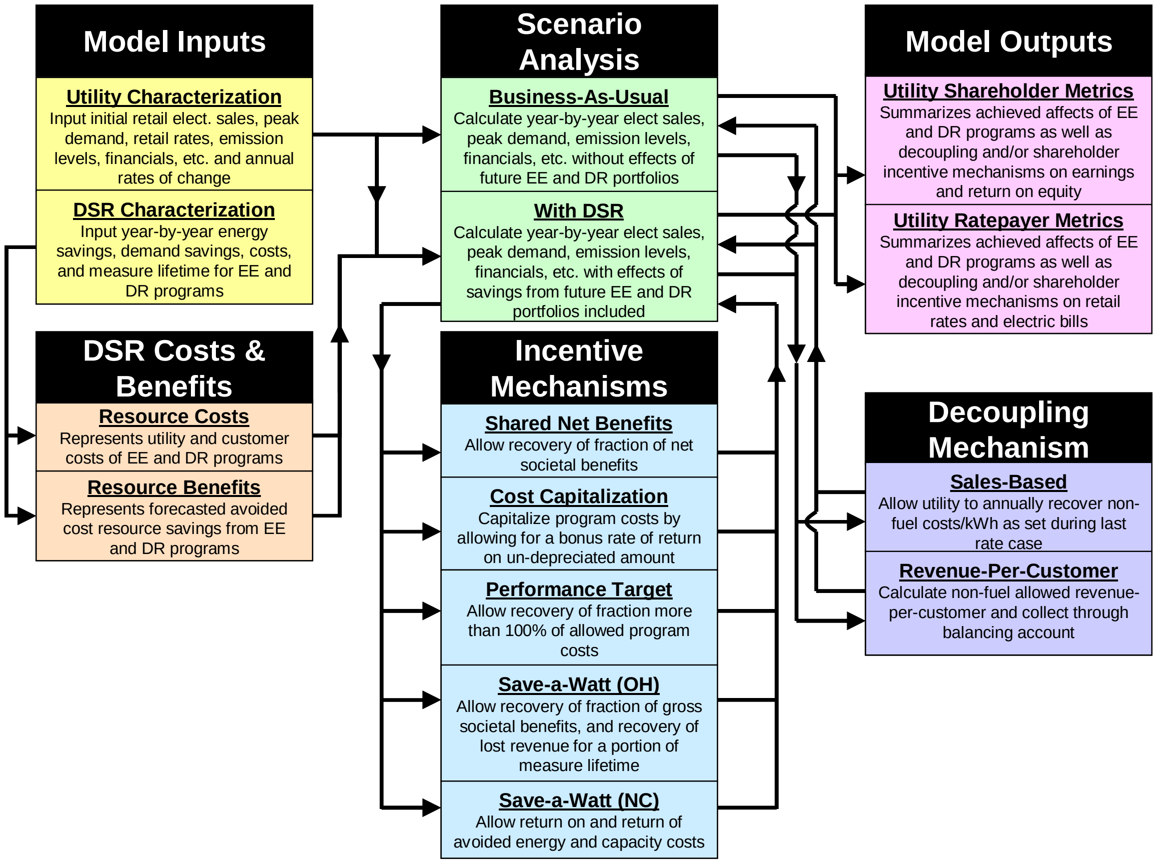



**Figure 5. Flowchart for quantitative analysis of EE incentive mechanisms at prototypical utility**

## 3.2 Prototypical Southwest Utility Characterization

For this analysis, we chose to characterize a prototypical utility from the southwestern region of the United States. Many utilities in this region are currently experiencing and forecasting a very high level of growth, as the U.S. populace migrates to warmer and drier climates. In this situation, energy efficiency has the potential to become an increasingly important resource that can help meet and mitigate projected load growth.

As shown in Figure 6, our prototypical southwest utility has first-year (2008) annual retail sales of 25,000 GWh, an initial peak demand of ~5,700 MW, which produces a 50% load factor.[30] Sales are forecasted to grow at a compound annual rate of 2.8% while peak demand is expected to expand at a slightly faster rate (2.9%). This forecast represents our "business-as-usual" scenario if energy efficiency is not implemented (BAU No EE),

[30] See Appendix A for more information on approach used to develop the prototypical southwest utility. We relied heavily upon publicly available data (e.g., annual reports, 10-K, FERC Form 1, integrated resource plans) predominantly from Arizona Public Service and Nevada Power.

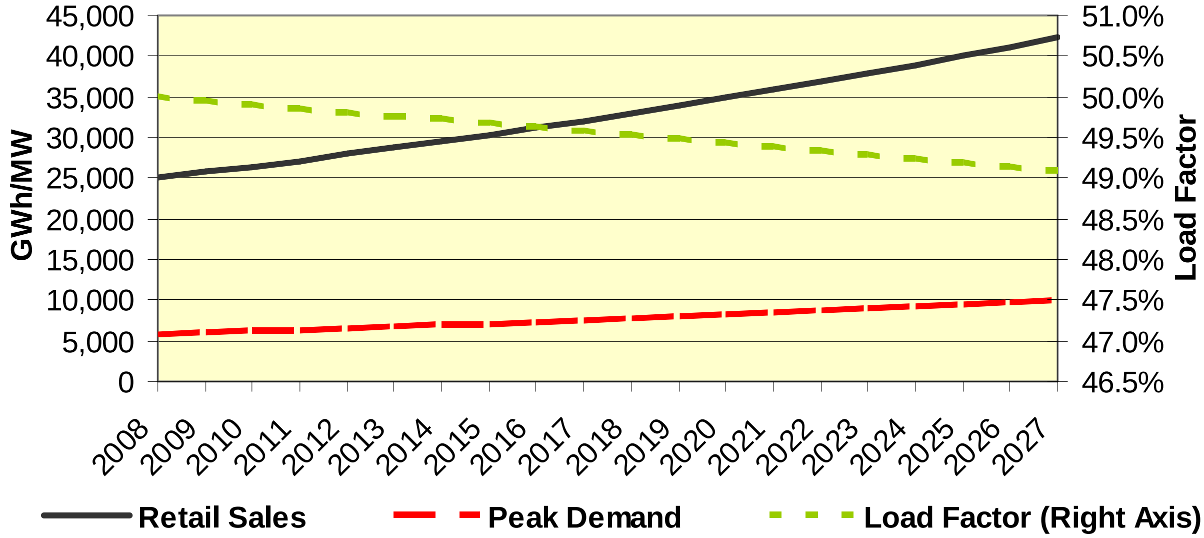



**Figure 6. Forecasted retail sales, peak demand and load factor for prototypical Southwest utility: Business-as-usual case**

Initially, the prototypical utility's generation fleet is assumed to be dominated by coal (45%), with 10% of its peak demand being met by its own renewable resources and 15% through its natural gas assets, leaving fully 30% of its needs to be met through purchased power. To serve customers' growing demand, the utility's base case resource acquisition plan includes additional base load generation (i.e., coal-fired generation), mid-merit plants (i.e., combined-cycle natural gas), peaking units (i.e., combustion turbines) as well as new investments in its transmission and distribution system. Figure 7 shows how the resource requirement to meet peak demand changes over the analysis period.[31] Because of the significant growth in new plant and T&D assets, fixed and variable O&M expenses are expected to grow at an annual rate of 8.8%. In aggregate, non-fuel utility costs are expected to increase by 6.4% annually over the 20 year time horizon. Given this load and resource base, the prototypical utility has an all-in average retail rate of 9.1 ¢/kWh in 2008, which increased to 18.9 ¢/kWh by 2027 (see right axis of Figure 7).

[31] The fuels explicitly indicated in Figure 3 represent the utility's owned and operated generation fleet. Purchased power can be comprised of any fuel source; we assume that over time, purchased power is assumed comprised of renewable resources in order to meet an RPS requirement, which is prevalent in the southwest.

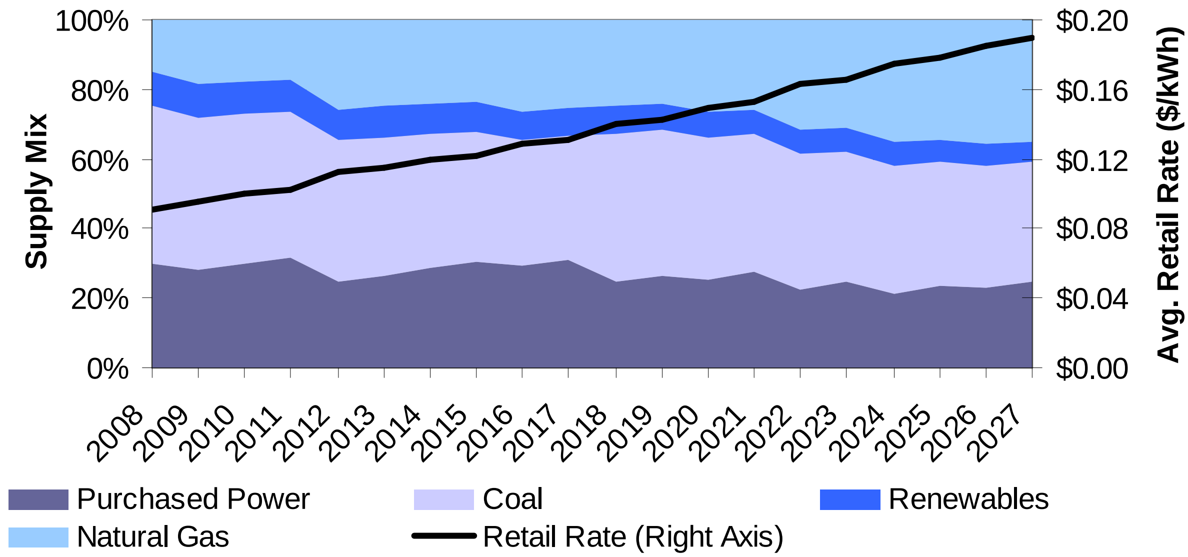



**Figure 7. Resource mix and average retail rates for prototypical Southwest utility: Business-as-usual No EE Case**

The avoided peak and off-peak energy costs are determined to be 7.0 ¢/kWh and 4.1 ¢/kWh in 2008, respectively; these values change annually to reflect differences in the portfolio of supply-side assets.[32] The avoided cost of capacity is initially set equal to $80/kW-year, which is a proxy for the annual carrying cost of a new natural gas combustion turbine, and is assumed to grow at an annual rate of 1.9% per year. In addition, the avoided cost of transmission and distribution capacity has a first year value of $30/kW-year, which increases at a rate of 1.9%/year over the analysis period.[33] The utility is assumed to have the ability to fully pass through all fuel expenses via a fuel adjustment charge and receives cost recovery for construction work in progress (CWIP) through a rate rider. We further assume the utility's capital structure is split 50:50 to debt and equity, where the cost of debt is 6.6% and the utility's authorized return on equity is 10.75%. The prototypical utility is forecasting increases in costs in all aspects of its business and utility costs are growing more rapidly than sales. Thus, between rate cases this prototypical utility experiences earnings erosion – it is unable to achieve its authorized ROE, and hence earnings level, in non-rate case years. In our base case, we assume that the utility files a rate case every other year (using a current test year methodology). The utility is able to achieve 97% of its authorized earnings (Figure 8), driven in part by these relatively frequent rate cases and its performance.[34] We also show "unachieved earnings" which is the erosion in utility earnings compared to authorized levels (i.e., 10.75% ROE).

[32] Our definition of the peak period corresponds to the standard 16-hour window used in most forward electric market contracts.

[33] For energy efficiency, the appropriate values to use for estimating the avoided cost of transmission and distribution capacity are very location-specific. The benefits of deferring T&D capacity are only achieved if the savings from energy efficiency programs are targeted and occur in areas where additional T&D investment can be avoided. For this reason, we de-rated the avoided T&D capacity benefits by 50% on the assumption that not all implemented energy efficiency measures are in locations that can help defer future investments in the T&D system.

[34] This frequency of general rate case filings is not without precedent. Arizona Public Service has filed rate cases in three of the last five years (i.e., 2004, 2006 and 2008).

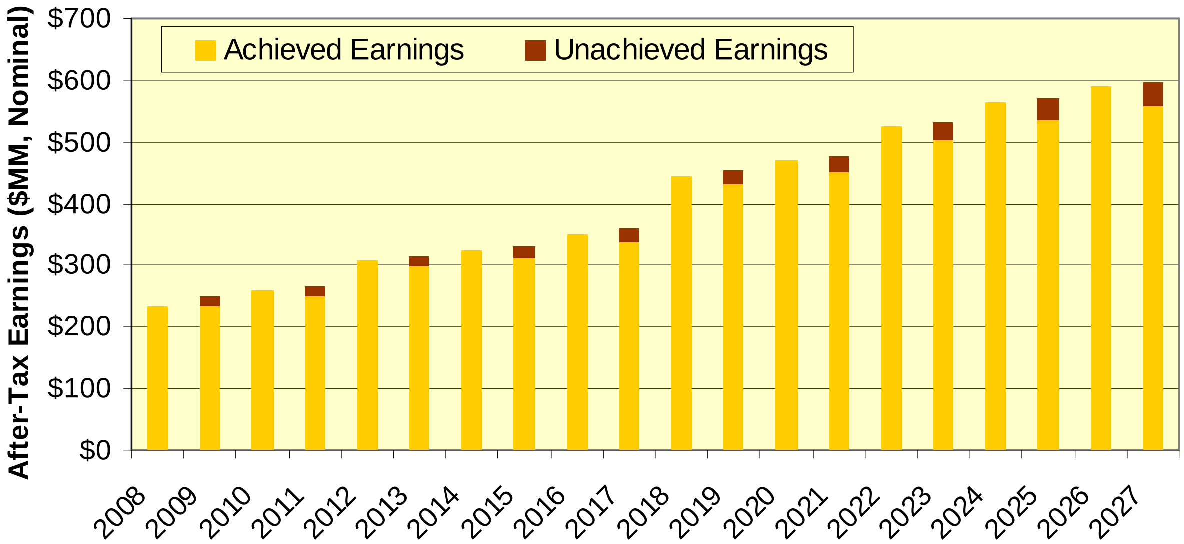



**Figure 8. Annual after-tax earnings of prototypical Southwest utility: Business-as-usual No EE case**

The regulatory commission that oversees the utility is considering three sets of energy efficiency savings goals over a ten-year period starting in 2008 (see Table 1):

1. **Moderate EE Portfolio**: To achieve a 0.5%/year incremental reduction in annual retail sales within two years of starting and maintain this level of incremental energy savings each year for the next 8 years. This portfolio of energy efficiency programs has a weighted-average measure lifetime of 11 years, and produces total lifetime savings of 14,931 GWh and a maximum reduction of peak demand equal to 226 MW when implemented over a ten year period. The total resource costs for the programs included in the Moderate EE portfolio are 2.6 ¢/lifetime kWh in 2008, and are assumed to increase at 1.9% per year thereafter.[35]
2. **Significant EE Portfolio**: To achieve a 1.0%/year incremental reduction in annual retail sales within three years of starting and maintain this level of incremental energy savings each year for the next 7 years. This portfolio of energy efficiency programs also has a weighted measure lifetime of 11 years, and produces a total lifetime savings of 27,761 GWh and a maximum reduction of peak demand equal to 421 MW when implemented over a ten year period. The total resource costs for the programs included in the Significant EE portfolio are 3.0 ¢/lifetime kWh in 2008, and are assumed to increase at 1.9% per year thereafter.
3. **Aggressive EE Portfolio**: To achieve a 2.0%/year incremental reduction in annual retail sales within five years of starting and maintain this level of incremental energy

[35] At the end of the measure's useful lifetime, it is assumed that the participant will replace the measure in order to maintain the level of savings. Moreover; we assume that 80% of the current EE portfolio is comprised of measures that will be included in appliance and equipment efficiency standards or building codes over the next 10-15 years. Thus, in estimating future resource costs, we assume that there is no incremental measure cost borne by the participant to maintain the same level of energy and demand savings for this 80% of the portfolio. The remaining 20% will be replaced by the participant at inflation-adjusted total measure costs at the time such measures reach the end of their lifetime.

savings each year for the next 5 years. With a weighted measure lifetime of 11 years, this portfolio of programs produces total lifetime savings of 49,021GWh and a maximum reduction of peak demand equal to 743 MW when implemented over a ten year period. The total resource costs for the programs included in the Aggressive EE portfolio are 4.0 ¢/lifetime kWh in 2008, and are assumed to increase at 1.9% a year annually thereafter.

**Table 1. Key features and impacts of alternative energy efficiency portfolios**

| | | | | | Lifetime Impacts | | | |
|---|---|---|---|---|---|---|---|---|
| **Energy Efficiency Portfolio** | **Target % Reduction in Incr. Retail Sales** | **Ramp Up Period (Years)** | **Ratio of Energy Savings to Peak Demand Savings (MWh per MW)** | **Measure Lifetime (Years)** | **Peak Period Savings (GWh)** | **Off-Peak Period Savings ( GWh)** | **Peak Demand Savings (Max MW)** | **Resource Costs (¢/ Lifetime kWh)** |
| **Moderate** | 0.5%/Year | 2 | 6,000 | 11 | 10,452 | 4,479 | 226 | 2.6 |
| **Significant** | 1.0%/Year | 3 | 6,000 | 11 | 19,433 | 8,328 | 421 | 3.0 |
| **Aggressive** | 2.0%/Year | 5 | 6,000 | 11 | 34,314 | 14,706 | 743 | 4.0 |

We assume that approximately 70% of the savings occur in the peak energy period from measures installed as part of the set of EE programs.[36] In estimating the peak demand impacts of the various EE portfolios, we assume that the ratio of energy to peak demand savings is 6000 MWh of savings to achieve a one MW reduction in peak demand.

The impacts of the program on the utility's retail energy sales forecasts and peak demand levels are graphically displayed in Figure 9 for 2012, when all programs are fully ramped up, and for 2017, when all EE programs have been fully implemented by the utility. Savings from implementing the Aggressive EE Portfolio offsets over 60% of growth in retail sales in 2017, and nearly 45% of the growth in peak demand.

[36] See Appendix A for a more detailed description of the development of alternative energy efficiency portfolios. We defined the peak period to include a standard 16 hour time window used in wholesale power forward markets (e.g. 8 AM -10 PM weekdays). Given this lengthy peak period, 70% of the savings are assumed to occur during the weekday peak period, with 30% of the savings occurring in the off-peak hours.

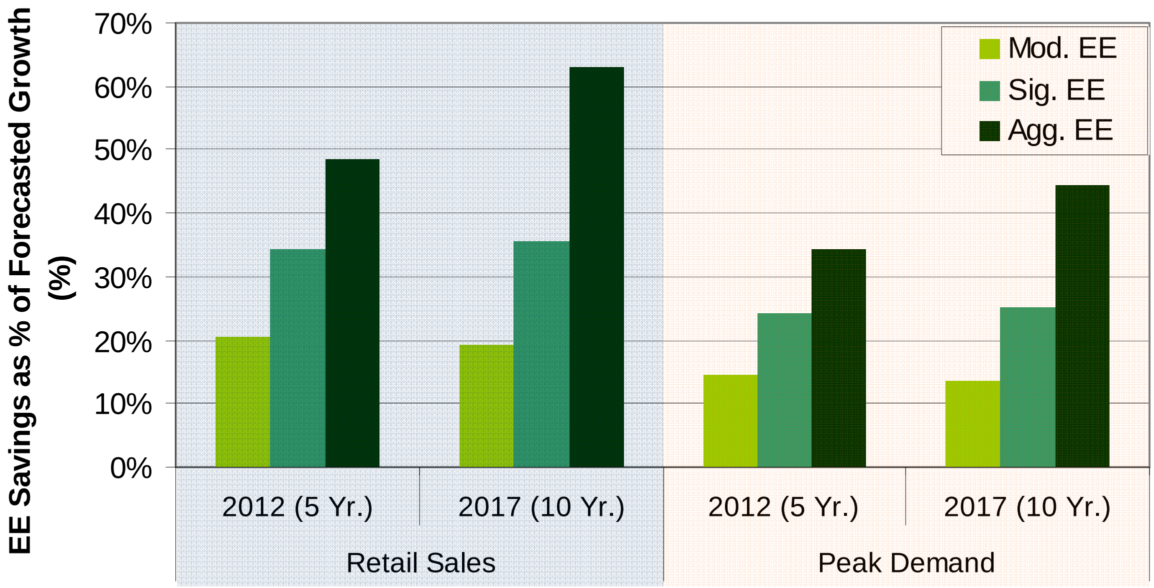



**Figure 9. Energy savings from EE portfolios as percent of prototypical Southwest utility forecasted load growth**

The implementation of energy efficiency has multiple and sometimes countervailing impacts on the utility's cost of service (i.e., revenue requirement). On the one hand, the utility will incur program administration and measure incentive costs between 2008 and 2017 that are expensed in the year that EE measures are installed, thereby increasing the utility's annual cost of service. However, the reduced level of retail sales also results in lower fuel and purchased power budgets and deferred investment in the local distribution system and additional generation capacity.

Depending upon the regulatory mechanisms in place, these cost savings from energy efficiency are either retained by the utility or passed through to ratepayers. The existence of a Fuel Adjustment Clause (FAC) results in the cost savings from reduced fuel and purchased power budgets flowing to ratepayers in a timely fashion. The utility's ability to collect Construction Work In Progress (CWIP) allows it to increase retail rates as large capital expenditures (e.g., new generation facilities) are incurred. Conversely, if these capital expenditures are deferred due to reduced peak demand and retail sales levels from energy efficiency, these cost savings are also captured by ratepayers in the current time period as such large capital expenditures are pushed into the future. Maintenance and upgrades to the local distribution system are undertaken without explicit cost recovery through some balancing account mechanism, rather these budgets must be covered as part of collected revenue. To the degree these T&D capital expenditure budgets exceed those set during the last rate case, the utility will loose money on these activities until the next GRC is filed. However, if the utility incurs fewer expenses than it budgeted for in the last rate case, the cost savings are retained by the utility until such time as it files the next rate case with these lower capital expenditure budgets. In aggregate over the twenty year time horizon, total achieved utility cost savings from energy efficiency ranges between $1.23 to $3.07 billion for the Moderate and Aggressive EE portfolios, respectively (Figure 10), while the bulk of these benefits are captured by customers (between 77% and 90%).

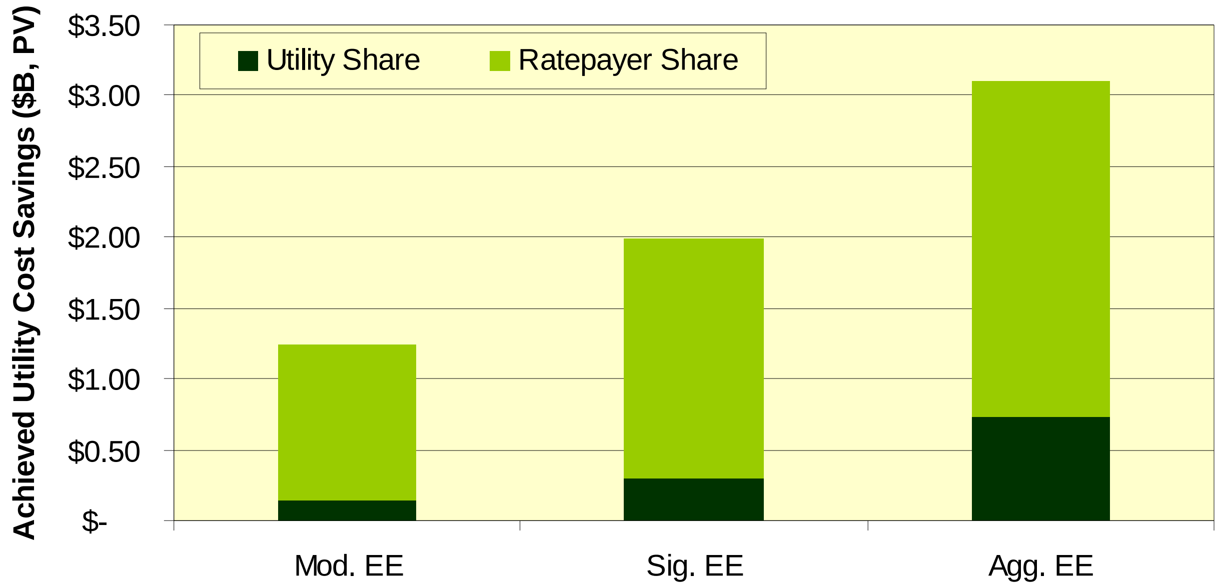



**Figure 10. Prototypical Southwest utility and ratepayer share of cost savings from energy efficiency compared to Business-as-usual No EE case**

The combined effect of these various elements on the utility cost of service results in retail rates changing considerably as ever more aggressive EE savings goals are achieved in the first 10 years of program implementation. However, once all the EE measures are installed, retail rates deviate minimally as these EE measures produce savings over their economic lifetime and are replaced at owners' expense (Figure 11). This trend is easiest to observe if one looks at the retail rates associated with the Aggressive EE portfolio. To achieve this deep level of savings, the utility must expend a considerable amount of money in the first 10 years, which increases retail rates somewhat between 2008 and 2017 relative to the BAU No EE level (e.g., by nearly 1 ¢/kWh in 2014). Yet, once these EE measures are installed, retail rates differ only by ~0.4 mills/kWh between 2018 and 2027 relative to the BAU No EE level. The deferral value of generation assets is also illustrated in Figure 11. In 2012, the prototypical utility plans to bring a 551 MW combined-cycle gas turbine plant on line in the business-as-usual No EE case, causing retail rates to jump by 1.1 ¢/kWh from 2011 levels. With the implementation of energy efficiency, this plant is deferred by one year, causing rates to only rise between 5 and 8 mills/kWh from 2011 to 2012, for the Moderate and Aggressive EE portfolios respectively. Once the new CCGT plant comes on line in 2013, the date of service now that energy efficiency has pushed back the need, retail rates increase by only 8 mills/kWh from 2012 to 2013, illustrating how the utility's cost savings from reduced fuel and purchased power budgets as well as T&D capital expenditure budgets mitigates somewhat the impact of the large addition to rate base.

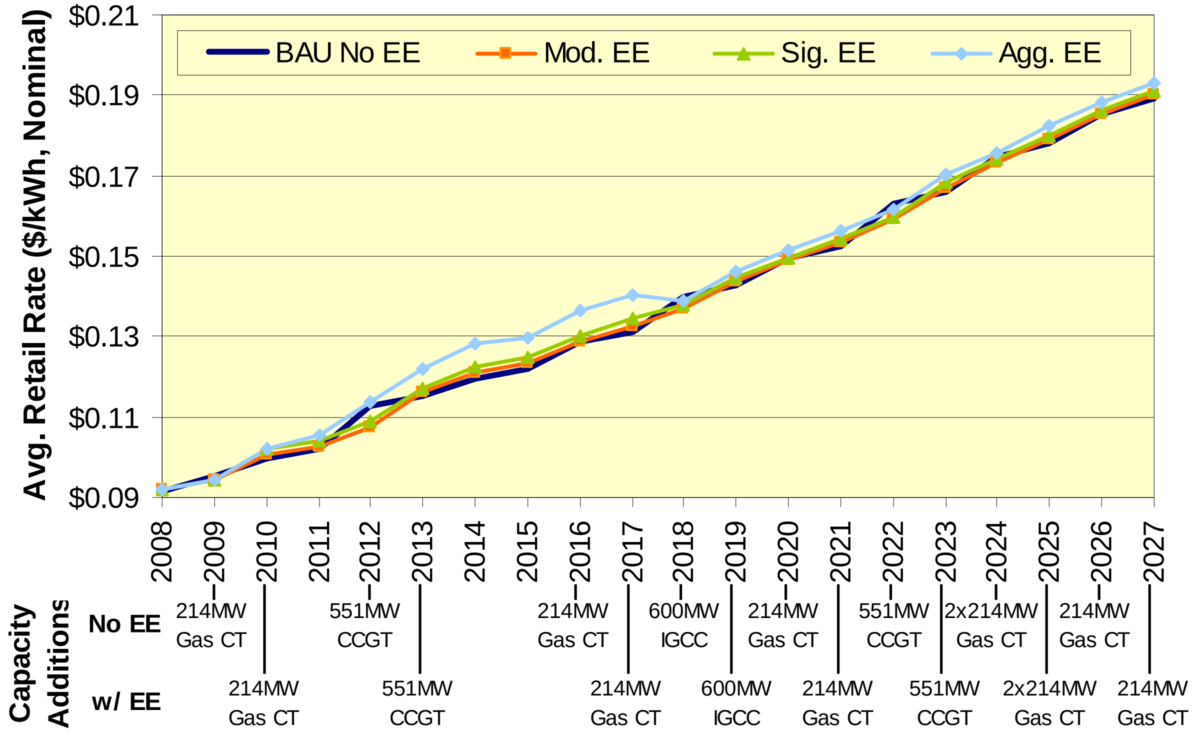



**Figure 11. Comparison of retail rates in "business-as-usual" No EE case vs. energy efficiency scenarios**

## 3.3 Overview of Shareholder Incentive and Decoupling Mechanisms

The state regulatory commission for our prototypical southwest is considering several policy and ratemaking options to help the utility overcome disincentives to aggressively pursue energy efficiency.[37] One option is to decouple the utility's sales from its revenue, thereby mitigating the potential for lost profit from any under-recovery of fixed costs through a reduction in retail sales between rate cases.

We chose to focus on the revenue-per-customer decoupling mechanism (see section 2.2.2.3). The actual allowed revenue collected by the utility is the product of the average revenue requirement per customer at the time of the last rate case and the current number of customers being served. The total revenue collected by the utility will change as the number of customers being served changes. A balancing account is used to ensure that ratepayers are either debited or credited for under- or over-collection of the authorized revenue requirement.

A second option is a financial incentive that rewards the utility for successfully achieving or exceeding electricity and/or peak demand reduction savings targets for their energy efficiency portfolio. We focus on five different shareholder incentives and present a comparative analysis of their impacts on various stakeholders (see section 2.2.3 for conceptual description of each

[37] See section 2.2 for a more detailed, conceptual discussion of the options available to regulators that want to align utility business interests with state policy objectives.

incentive mechanism). The first three incentive mechanisms have actually been implemented at a number of utilities over the last two decades. The last two incentive mechanisms have been proposed by Duke Energy and are more comprehensive in nature, combining several different objectives into a single mechanism. These are specifically:[38]

1. **Performance Target**: The utility receives an additional 10% of program administration and measure incentive costs for achieving program performance goals. Program costs are explicitly recovered in the period expended through a rider.
2. **Cost Capitalization**: The utility capitalizes program administration and measure incentive costs over the first five years of the installed measures' lifetime and is granted the authority to increase its authorized ROE (10.75%) for such investments by 500 basis points.
3. **Shared Net Benefits**: The utility retains 15% of the present value of the net benefits from the portfolio of energy efficiency programs. Program costs are explicitly recovered through a rider.
4. **Save-a-Watt NC**: The utility capitalizes 90% of the present value of generation costs avoided over the lifetime of the installed measures. This mechanism serves as a financial incentive for the utility to vigorously attain savings goals, but must also cover program costs and any associated lost earnings from reduced sales volume.[39]
5. **Save-a-Watt OH**: The utility retains 50% of the present value of the gross benefits from the portfolio of energy efficiency programs. Program costs are to be covered by this payment. In addition, there is an explicit additional "lost revenue" component that allows the utility to recover the first three-years of savings from each year's implemented measures or up until the time of the next rate case, whichever comes first, valued at the then existing average retail rate (excluding fuel).[40]

### 3.4 Base Case Results

We present results that show the financial effects of alternative energy efficiency portfolios on the utility's bottom line earnings and return on equity, customer bills and retail rates, and total resource benefits to the electric system. Our analysis framework assumes that a regulatory commission wants to better understand the implications for shareholders and utility customers of

[38] For each incentive mechanism, the utility's expected earnings are represented on an after-tax basis. Thus, ratepayers are obliged to pay an incentive mechanism to the utility that is grossed-up for the assumed 38% tax liability faced by the utility (e.g., local, state and federal government taxes).

[39] Duke Energy Carolina originally proposed Save-A-Watt in May 2007 to the North Carolina Utility Commission. Since then, they have filed it in South Carolina. Program costs are not explicitly recovered, but rather the Save-a-Watt incentive is intended to compensate the utility for them. In addition, this mechanism covers any loss of profit due to a reduction in sales. Thus, we do not consider implementing a decoupling mechanism in addition to Save-a-Watt (NC). See Appendix C for more detailed description of how Save-A-Watt (NC) was modeled in the Benefits Calculator.

[40] Duke Energy Ohio filed their revised Save-A-Watt proposal in Ohio on July 31, 2008, after settling on a similar version of the Save-a-Watt design with the Indiana Office of Utility Consumer Counselor (IOUCC). Program costs continue to be recovered as part of the incentive mechanism; any lost revenue associated with the successful implementation of energy efficiency and demand response is directly accounted for and recovered as a *separate* component of the mechanism. Duke Energy also agreed to an earnings cap on the contribution made by the incentive mechanism, absent any impact of the lost revenue component. Thus, we do not consider a decoupling mechanism because there is already a provision to recover fixed costs. See Appendix D for more detailed description of how the Save-A-Watt (OH) mechanism was modeled in the Benefits Calculator.

directing the utility to implement a portfolio of energy efficiency programs under several options: (1) without any supporting policies (e.g., implementing neither a decoupling nor a shareholder incentive mechanism), (2) offering only a revenue-per-customer decoupling mechanism, (3) offering only a shareholder incentive mechanism that does not explicitly include a lost margin recovery component (i.e., Performance Target, Cost Capitalization and Shared Net Benefits), or (4) alternatively combining a lost margin recovery/decoupling mechanism with a shareholder incentive either explicitly or implicitly. The first three options could be likened to an "á la carte" menu where the regulator has the ability to pick and choose which mechanisms to adopt or consider. The fourth option utilizes a comprehensive approach that bundles the potential policy options together.

We assume that the prototypical utility will achieve the energy efficiency savings goals in each EE portfolio regardless of the incentives offered. Thus, our analysis does not address issues related to the utility's preference for or differential response to various incentive and/or decoupling mechanisms (e.g., the degree to which each incentive mechanism would motivate a utility to increase energy efficiency programs). We also do not analyze potential non-financial motivators of utility behavior such as regulatory commission orders, legislative goals codified into law, customer satisfaction, or a perceived competitive threat if EE programs were administered by a non-utility entity.

#### 3.4.1 Effect of a Revenue-per-Customer Decoupling Mechanism

In Figure 12, we see that our prototypical utility earns about \$100M less than its authorized earnings over a 10 year period because costs are growing faster than revenues from sales. As the utility implements various energy efficiency portfolios, the savings reduce sales between rate cases, which increase the under-recovery of fixed costs (reflected in greater unachieved earnings shown in Figure 12). For example, with the Aggressive EE portfolio, the utility's ROE drops by 12 basis points relative to the "business-as-usual" (BAU) No EE case and "unachieved" earnings increase by ~\$30M over the 10 year period (Figure 12).[41] Implementing a revenue-per-customer (RPC) decoupling mechanism when EE is instituted helps to mitigate the erosion in the utility's authorized earnings. The RPC decoupling mechanism allows the utility to get very close to the "business as usual (BAU)" No EE case in terms of ROE (10.42%) across all three EE portfolios, which means that the utility should be financially indifferent to EE portfolios of various sizes (see Figure 12).[42]

[41] The return on equity metric that is reported throughout this document is calculated as a present value of the 20-year stream of earnings divided by the present value of the 20-year stream of outstanding equity. In essence, this is a weighted average representation that takes into account the time value of money, and thus should be a more applicable metric.

[42] With costs still growing faster annually than the number of customers, the revenue-per-customer decoupling mechanism is unable to collect enough from each customer between rate cases to allow the utility to achieve its authorized ROE. We have assumed that the sales growth rate is equal to the customer growth rate; this means that electricity use per customer is neither increasing nor decreasing over time. The consequence of this assumption is that when a revenue-per-customer decoupling mechanism is applied, the growth in collected revenue between rate cases is the same as the growth in collected revenue that occurs in the "business-as-usual" No EE case. Given the frequency of rate cases, the application of the RPC decoupling mechanism when EE is implemented results in the utility achieving the same ROE as when no energy efficiency was undertaken.

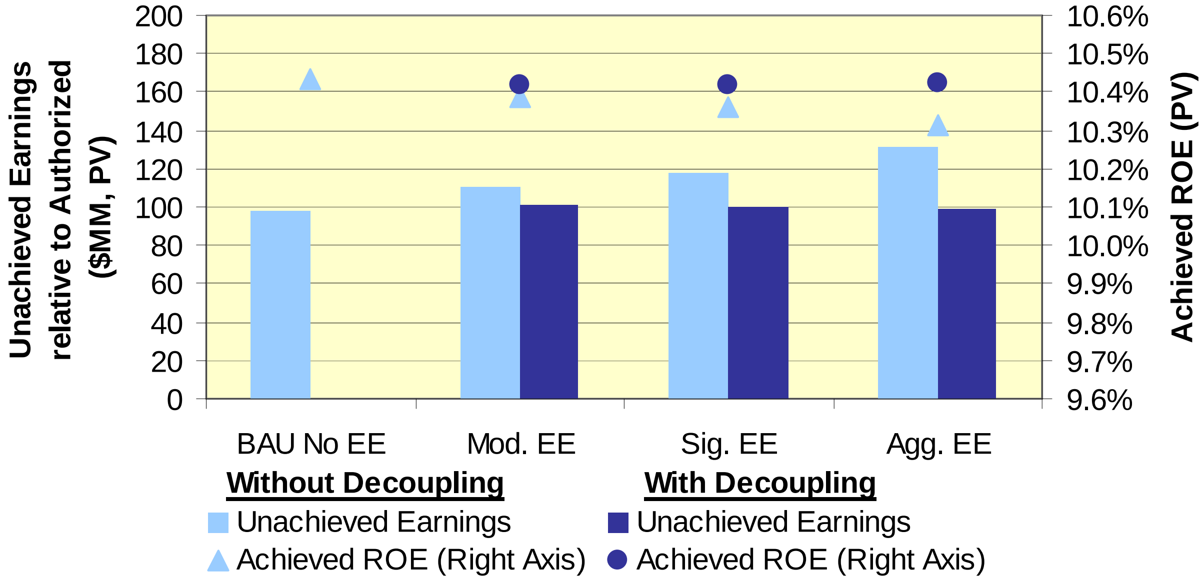



**Figure 12. Effect of decoupling on earnings and ROE**

### 3.4.2 Separate Application of Decoupling and Shareholder Incentive Mechanisms

The prototypical southwest utility experiences an $80M to $117M reduction in earnings when various EE portfolios are implemented (Figure 13) and up to a 12 basis point reduction in its achieved ROE.[43] Recall that our prototypical utility has a twenty-year present value (PV) of after-tax earnings equal to roughly $3.3B and achieves an ROE of 10.43% (on a PV basis). It is useful to examine the impact of decoupling or various shareholder incentive mechanisms on both earnings (Figure 13) for various EE portfolios as the results illustrate an important tension for utility shareholders/managers and a key issue for regulators.

If a Moderate EE portfolio is implemented, the utility sees achieved earnings drop between $19MM to $70MM compared to the BAU No EE case, depending if a Shared Net Benefits or RPC decoupling mechanism is implemented (see Figure 13). However, the utility's ROE is comparable to the BAU No EE case with decoupling and actually increases by 15 basis points with a Shared Net Benefits mechanism.

If the Significant EE portfolio is implemented, a utility would still not realize positive earnings opportunities with any of these mechanisms except Shared Net Benefits compared to the BAU No EE case. However, if we focus on ROE, then the overall picture looks different across a wider range of incentive mechanisms. The Performance Target and the Shared Net Benefits

[43] Energy efficiency programs reduce earnings and lower ROE because they defer the need for future investments in transmission, distribution and generation plant that otherwise would have generated additional earnings for the utility. Moreover, because program costs are expensed, the utility's investment in energy efficiency does not offer an opportunity to earn a return for shareholders. Because the utility needs to raise less capital with a large energy efficiency portfolio due to the deferral of future investments, the necessary contribution to earnings from a shareholder incentive mechanism for energy efficiency is typically much less than the contribution to earnings of these foregone capital investments.

mechanisms each have a positive impact on the utility's ROE as it increases by 4 and 26 basis points, respectively. In contrast, the Cost Capitalization mechanism requires the utility to issue additional equity, thus the improvement in the utility's ROE is only comparable to that achieved without any energy efficiency (i.e., BAU No EE case).

If the utility implements the Aggressive EE portfolio, after-tax earnings decrease by $86M with a RPC decoupling mechanism while earnings decrease by ~$2 to 38MM with a Cost Capitalization and a Performance Target incentive mechanism respectively. As with the Significant EE portfolio, the Shared Net Benefits mechanism is the lone one to provide a positive improvement in earnings, relative to the BAU No EE level (i.e., $12MM). Similarly, the utility's ROE increases the most under our Shared Net Benefits approach (by 31 basis points); ROE increases by about 15 basis points under Performance Target, and by 1 basis point under Cost Capitalization.

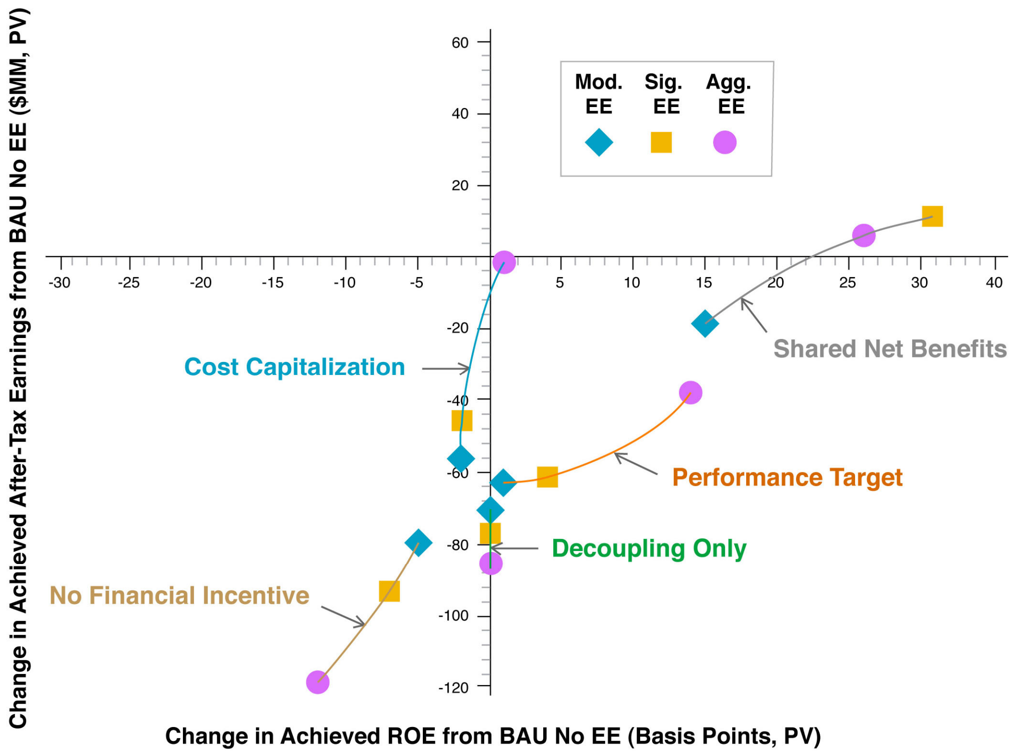



**Figure 13. After-tax earnings and return on equity (ROE): Impact of energy efficiency portfolios, decoupling and shareholder incentives**

From ratepayers' perspective, customers are interested in the magnitude of bill savings from energy efficiency relative to the costs required to implement programs and potential rate impacts. If the utility implements one of the energy efficiency portfolios (i.e., Moderate, Significant and Aggressive), aggregate bill savings for all customers are $1.1B, $1.69B, and $2.37B respectively if neither a decoupling nor shareholder incentive mechanism is provided to the utility (see Figure 14). Customer bill savings are reduced somewhat (at most by $99M to 208M) if a decoupling or shareholder incentive mechanism is implemented. Ratepayer bill savings under the three shareholder incentive mechanisms are still at least 90% of the level achieved if no financial benefit is provided to the utility.

The three EE portfolios have a modest effect on 20-year average retail rates; impacts vary among the three EE portfolios. If the utility implements the Moderate EE portfolio, there is either a small decrease in 20-year average retail rates (0.1 mill/kWh) with a decoupling mechanism or a small increase (0.2 mills/kWh or less) over the planning horizon with any of the shareholder incentive mechanisms. If the utility implements the Significant EE portfolio along with one of the incentive mechanisms, average retail rates increase by 1.0-1.4 mills/kWh over the 20-year period compared to the Business-As-Usual (BAU) No EE case. If the utility implements the Aggressive EE portfolio in conjunction with an incentive mechanism or decoupling, average retail rates are 3.6-4.2 mills/kWh higher over the 20 year period compared to rates in the BAU No EE case (Figure 14).

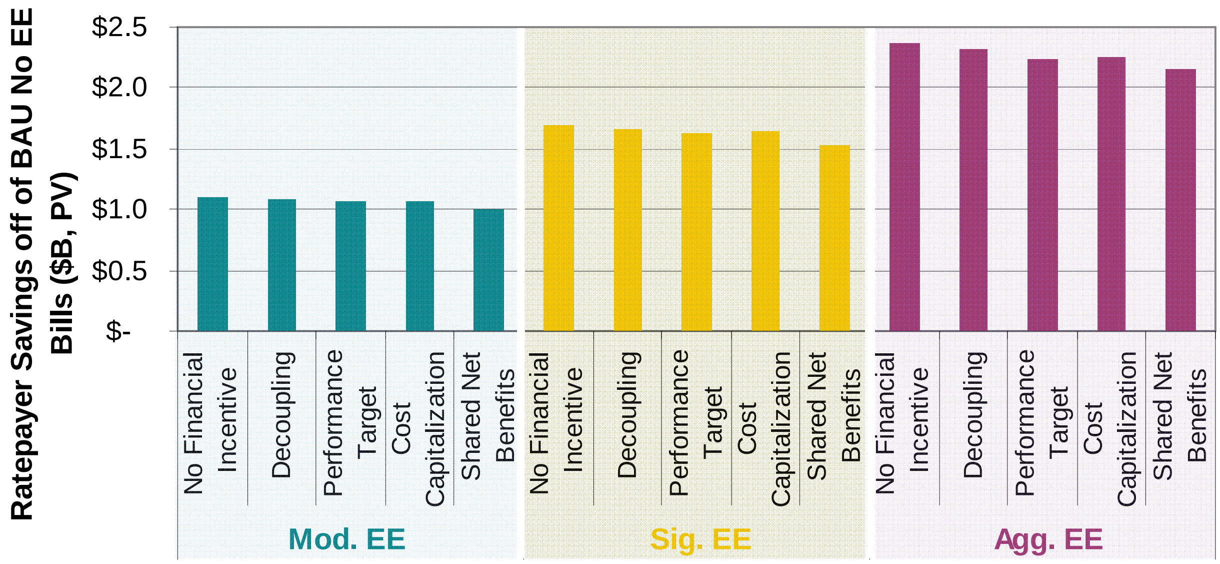



**Figure 14. Ratepayer bill savings: Impact of energy efficiency portfolios, decoupling and shareholder incentives**

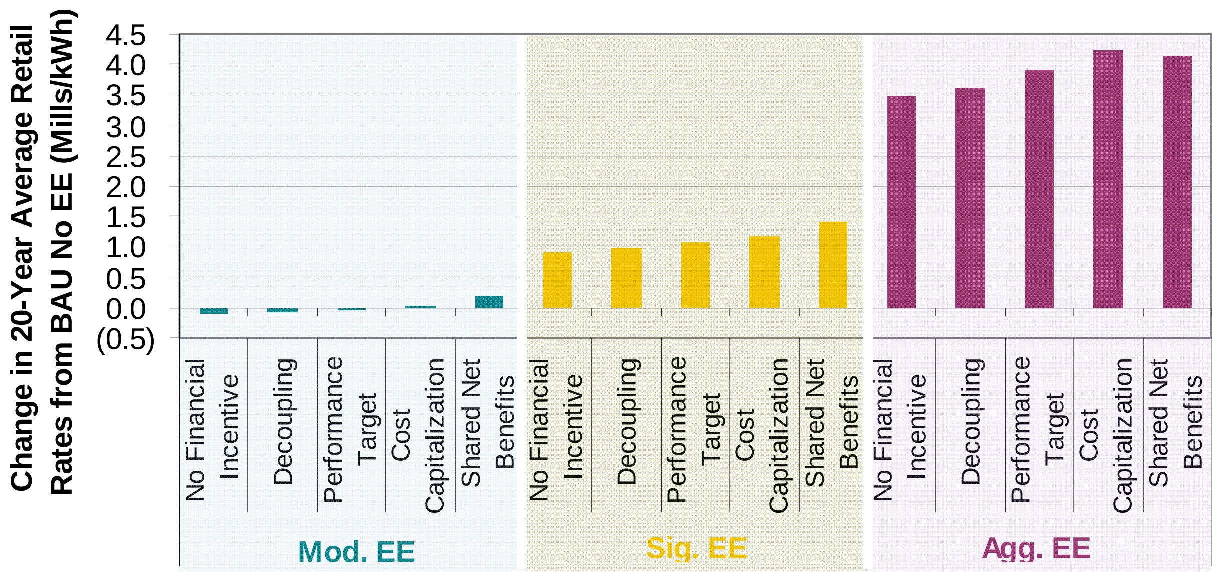



**Figure 15. Retail rates: Impact of energy efficiency portfolios, decoupling and shareholder incentives**

The utility's cost of service savings, which translates into customer bill savings and retail rate impacts, can be disaggregated into several cost components: costs related to generation, transmission and distribution-related costs, and EE program costs (see Figure 17). The bulk of the reduction in the utility's cost of service due to energy efficiency comes from reduced generation-related expenses (i.e., which range from 1.0B under the Moderate EE scenario to $2.8B in the Aggressive EE scenario). The T&D-related cost savings are relatively small (~$250M) and do not change much among the three EE portfolios, in part because of our modeling assumption that energy efficiency programs only have a limited ability to defer T&D investments. Figure 17 also shows the change in retail rate components with various energy efficiency portfolios compared to the BAU No EE case. Retail rates associated with generation costs decrease, but are offset somewhat by the increase in rates to recover energy efficiency program costs. Rates associated with transmission and distribution-related costs also increase for the three EE portfolios because T&D costs must be recovered over a reduced sales base and because T&D cost savings from energy efficiency are less than the reduction in consumption associated with energy efficiency. The net impact of these changes to the various rate components results in a modest increase in the all-in retail rate (from 0.1 to 3.7 mills/kWh) if the utility implements various EE portfolios and recovers its revenue requirement.[44]

[44] We portray an all-in retail rate where the entire revenue requirement is collected through volumetric charges. For this reason, the change in retail rates is a function of how the revenue requirement is reduced relative to the reduction in retail sales. If the revenue requirement is falling at a slower rate than sales are dropping, retail rates must increase for the utility to successfully collect its authorized revenue requirement at that level of retail sales.

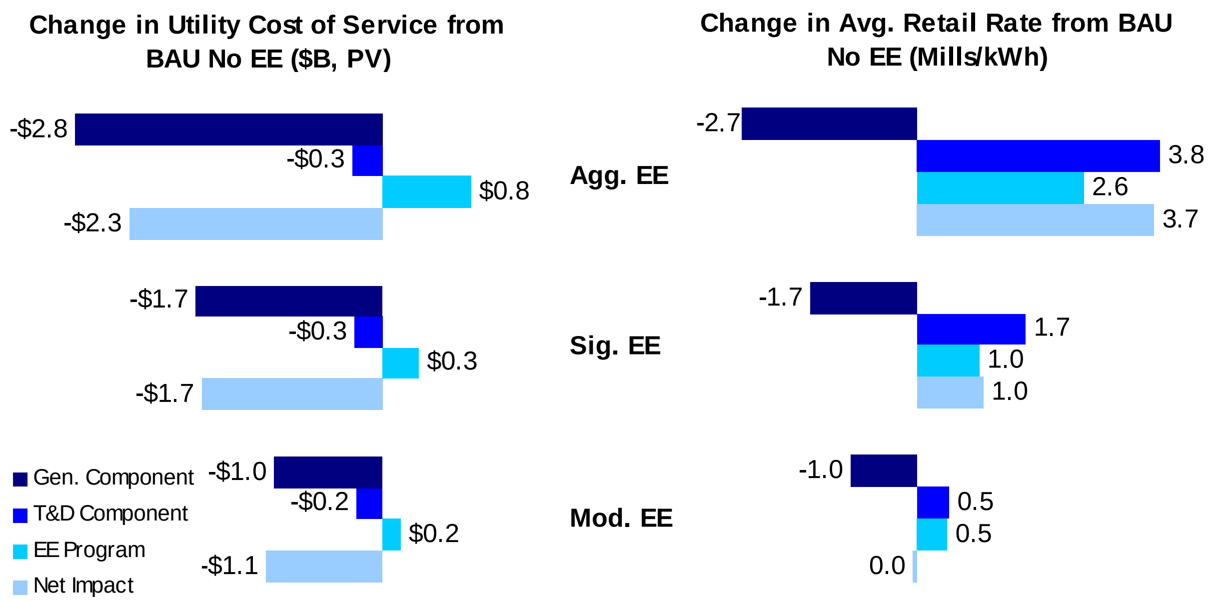



**Figure 16. Decomposition of the change in utility's cost of service and retail rates due to energy efficiency**

In reviewing energy efficiency incentive mechanism proposals, a regulatory agency also needs to be cognizant of their potential impact on the overall level of EE program costs and the proposed allocation of net resource benefits between ratepayers and utility shareholders. Some stakeholders may assess and compare the utility's proposed earning opportunity to EE program costs and raise the following issues: (1) what is a fair return on investment for the utility as administrator and (2) what is the potential impact of the additional earnings on rates and bills? Regulatory agencies and stakeholders will also assess whether a proposed incentive mechanism provides customers with an appropriate and fair share of the net resource benefits from implementing an EE portfolio. In Table 2, we show the three incentive mechanisms expressed in terms of the shareholder incentive as a percent of program cost and ratepayer share of net resource benefits for the three EE portfolios. We would highlight the following results.

First, as designed, the majority of incentive mechanisms provide most of the net resource benefits to ratepayers. The ratepayer share of net benefits is relatively high (76-94%) for our Performance Target, Cost Capitalization, and Shared Net Benefits mechanism under any of the EE portfolios.

Second, as designed, the Performance Target and Cost Capitalization mechanisms represent a moderate share of total program costs (~15-16%). Incentive levels as a percent of program costs remain constant across all three EE portfolios because the earnings basis is tied directly to program costs.

Third, in contrast, for Shared Net Benefits, incentive levels as a percent of program costs decrease if the utility implements EE portfolios with higher savings goals. The Shared Net Benefits incentive would represent about 26% of program costs if the Aggressive EE portfolio was implemented but a much higher share of program costs (49-61%) if the Significant and Moderate portfolios were implemented.

**Table 2. Metrics used to assess the cost and fairness of utility shareholder incentives**

| | Pre-Tax Incentive as % of Program Cost | | | Ratepayer Share of Net Benefits | | |
|---|---|---|---|---|---|---|
| **Incentive Mechanism** | **Mod. EE** | **Sig. EE** | **Agg. EE** | **Mod. EE** | **Sig. EE** | **Agg. EE** |
| Performance Target | 16% | 16% | 16% | 94% | 92% | 85% |
| Cost Capitalization | 15% | 15% | 15% | 94% | 93% | 86% |
| Shared Net Benefits | 61% | 49% | 26% | 76% | 76% | 76% |

#### 3.4.3 Effects of Jointly Offering a Lost Revenue and Shareholder Incentive Mechanism

It is also possible to combine mechanisms that address both "lost revenues" and also provide the utility with an opportunity for additional earnings for implementing an EE portfolio effectively. In this section, we explore the impacts on earnings, customer bills and rates, and net resource benefits if a Performance Target, Cost Capitalization or Shared Net Benefits shareholder incentive is implemented in conjunction with an RPC decoupling mechanism or alternatively, if one of the Save-a-Watt approaches proposed by Duke Energy (i.e., Save-a-Watt NC or Save-a-Watt OH) is implemented.

As noted earlier, it is important to examine the combined impact of decoupling and various shareholder incentive mechanisms on both earnings and ROE for various EE portfolios as the results illustrate an important tension for utility shareholders/managers and a key issue for regulators.

In Figure 17, we show the after-tax earnings of the prototypical utility over the 20-year planning horizon under various cases: Business-As Usual (BAU) case with no energy efficiency and the three EE portfolios implemented under various incentive mechanisms. In showing after-tax earnings, the stacked bars allow us to distinguish between the utility's base level of earnings that are linked to generation and T&D assets, earnings that are driven by energy efficiency investments, and earnings that result from a "lost revenue" or decoupling mechanism and compensate the utility for under-recovery of fixed costs due to reduced sales from energy efficiency. We would highlight several key results.

First, under all three EE cases, Save-A-Watt (NC) as proposed by Duke Carolina provides the prototypical utility with significantly higher earnings and ROE than any of the other approaches that combine decoupling and a shareholder incentive mechanism. For example, Save-A-Watt (NC) increases earnings between $215 and $602 million and ROE by 93 to 227 basis points for the Moderate and Aggressive EE portfolios respectively compared to the BAU No EE case. The increase in ROE provided to the utility by a Save-A-Watt mechanism is typically 5 to 10 times higher than any other combined decoupling/incentive mechanism. The Save-A-Watt (Ohio) mechanism is much less lucrative to shareholders than Save-A-Watt (NC) and provides slightly lower returns than a combined Shared Net Benefits and decoupling mechanism. If the prototypical utility had implemented a Save-A-Watt (OH) mechanism, its ROE would increase by 33 basis points in the Aggressive EE case as compared to the combined Shared Net Benefits and decoupling mechanism which increases ROE by 42 basis points.

Second, the *earnings* of the prototypical utility generally increase if it implements the Significant and Aggressive EE portfolios and has both a decoupling and shareholder incentive mechanism compared to the BAU No EE case (see Figure 17). If the utility implements the Moderate EE portfolio, utility *earnings* are still somewhat lower for all incentive mechanisms compared to the BAU NO EE case except for Shared Net Benefits and Save-A-Watt (NC).

Third, the utility's *ROE* improves if it implements any of the EE portfolios and has both a decoupling and shareholder incentive mechanism compared to the BAU No EE case (Figure 18). It is worth noting that, for any EE portfolio, the Cost Capitalization mechanism generally provides the utility with the smallest increase in ROE compared to other incentive mechanisms because the utility must issue additional equity to cover the capitalization of program costs (Figure 18).

Fourth, the lost margin recovery component of the Save-A-Watt (OH) mechanism contributes somewhat more to earnings than does the RPC decoupling mechanism when applied jointly with a shareholder incentive mechanism. For example, if the utility implements the Aggressive EE portfolio, 35% of the earnings contribution comes from the Save-A-Watt (OH) lost margin recovery component, rather than the shareholder incentive. In contrast, the RPC decoupling mechanism provides about 22-29% of the earnings that arise from Aggressive energy efficiency portfolio investments for the other three incentive mechanisms (e.g., Performance Target, Cost Capitalization, and Shared Net Benefits). It is worth noting that if the time between rate cases was longer such that our prototypical southwest utility was able to fully recover three-year's worth of lost margins, then that component of the Save-a-Watt (OH) incentive mechanism would have contributed at least 50% more towards after-tax earnings than we are currently showing in the Aggressive EE case.

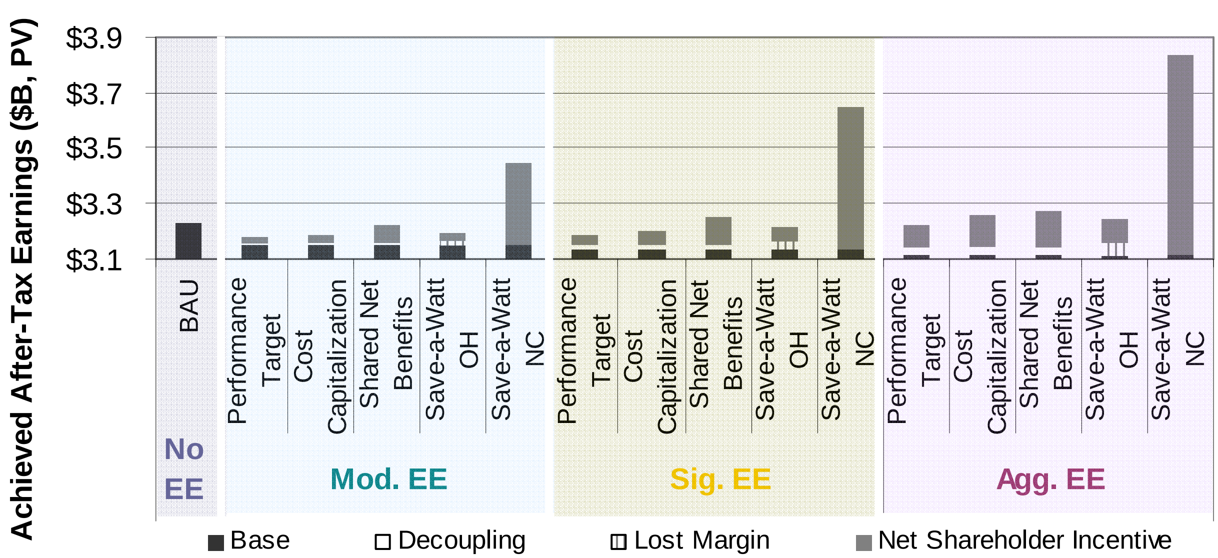



**Figure 17. After-tax earnings: Combined effect of fixed cost recovery and shareholder incentive mechanisms**

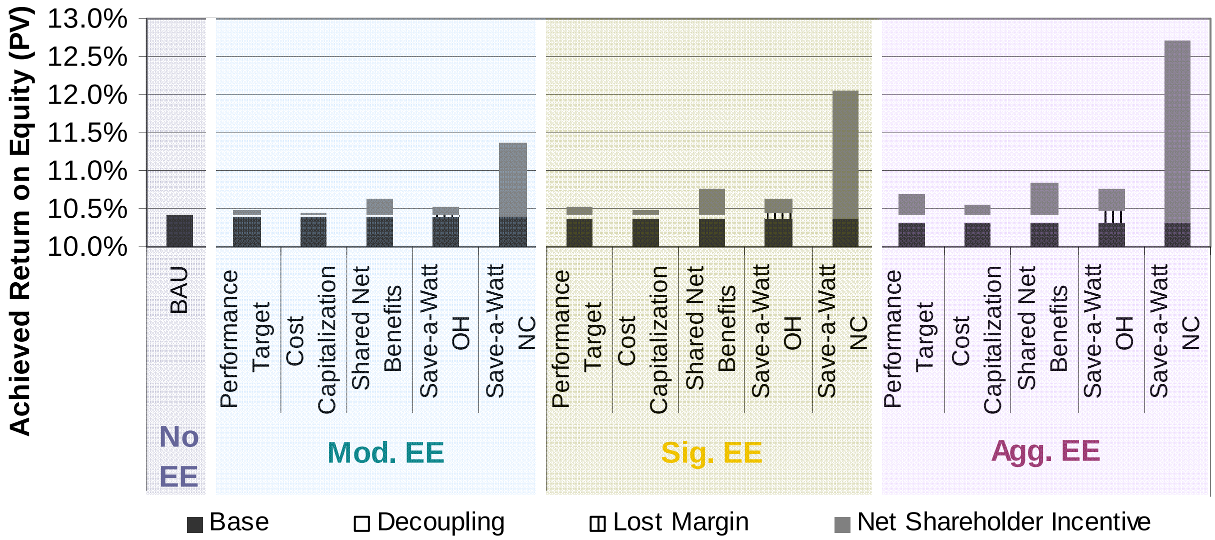



**Figure 18. Return on equity (ROE): Combined effect of fixed cost recovery and shareholder incentive mechanisms**

In Figure 19, we show ratepayers bills under the BAU No EE case and three EE portfolios implemented with a combined fixed cost recovery and shareholder incentive mechanisms over the 20-year planning horizon. Under the BAU No EE case, the present value of customer bills is \$36.7B over the planning horizon; ratepayer bills range between ~\$34.3 and ~\$35.6 billion for the various EE portfolio cases (Figure 19), which equates to a savings of roughly \$1.1B to \$2.4B. Not surprisingly, the incentive mechanisms that provide the lowest additional earnings to utility shareholders (e.g. Performance Target/RPC decoupling) produce the largest bill savings to ratepayers (assuming of course that the utility achieves the same level of savings under each incentive mechanism). The Performance Target incentive costs ratepayers \$26, \$53, and \$128 million for the Moderate, Significant and Aggressive EE portfolios respectively, while the decoupling mechanism contributes an additional \$16, \$28 and \$51 million respectively. At the other extreme, with Save-A-Watt (NC), the prototypical utility still achieves positive bill savings under the three EE portfolios although the utility's additional earnings for the three EE portfolios cost ratepayers between \$476MM to \$1.16B.

In Figure 20, we show the impact of decoupling plus incentive mechanisms or the proposed Save-A-Watt mechanisms on the average retail rates of the prototypical utility over the 20 year period. Depending on the EE portfolio, average retail rates are about 1-6 mills/kWh higher over the 20 year period compared to the BAU No EE case for all incentive mechanisms except Save-a-Watt NC, where rates are 9 mills/kWh higher in the Aggressive EE portfolio (Figure 20). The contribution of decoupling to rates is fairly small (and constant) across the three EE portfolios, as is the contribution of the lost margin component in Duke's Save-a-Watt (OH) mechanism. The shareholder incentive raises rates more as the aggressiveness of the EE performance goals increases. This can most easily be observed by looking at the Save-a-Watt (NC) series of bars, where the contribution of the net shareholder incentive grows substantially as the level of savings increases.

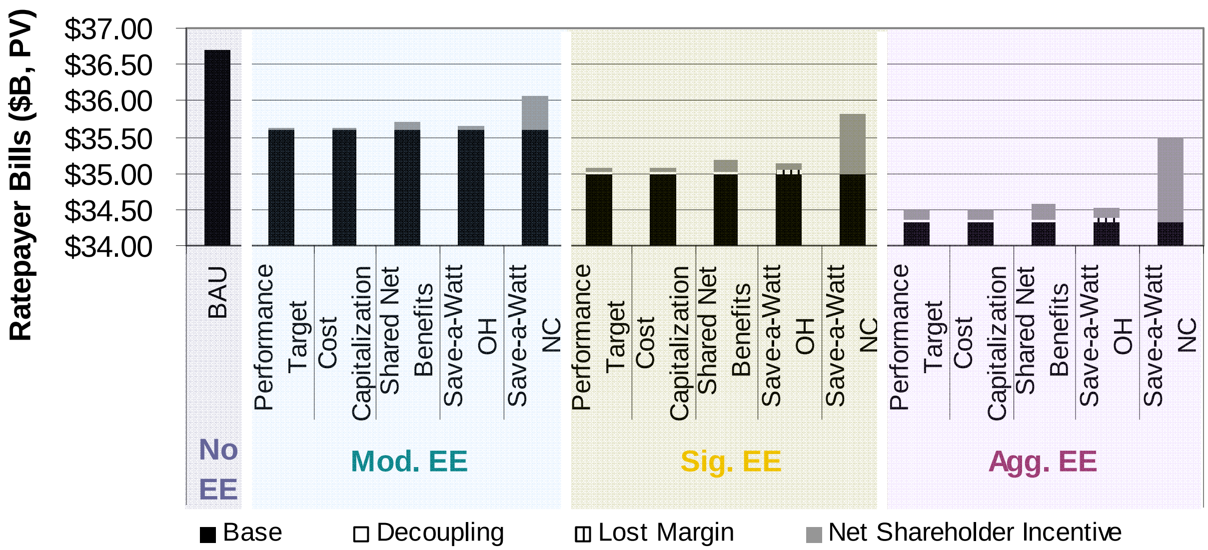



**Figure 19. Ratepayer bills: Combined effect of fixed cost recovery and shareholder incentive mechanisms**

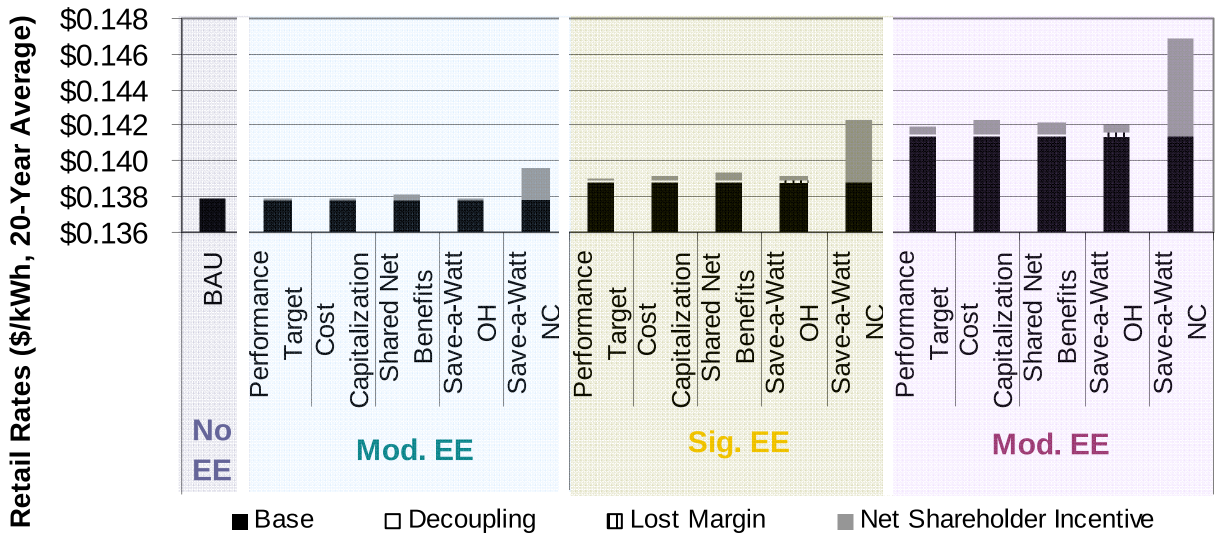



**Figure 20. Average retail rates: Combined effect of fixed cost recovery and shareholder incentive mechanisms**

State regulators (and other parties) are also interested in assessing the societal benefits and impacts of implementing these EE portfolios. Total resource benefits from the various EE portfolios significantly exceed resource costs for all shareholder incentives except Save-A-Watt (NC).[45] The Moderate EE portfolio provides total resource benefits of $672 million, while the

[45] It is important to note the distinction in the time period used to produce the different reported metrics. Thus far, all utility, shareholder and ratepayer metrics have used a 20-year time horizon. When assessing the total resource

Significant and Aggressive EE portfolios provide the utility with $1.22 billion and $2.06 billion of resource benefits respectively, compared to the BAU No EE case (Figure 21).[46] The total resource costs of the three EE portfolios vary by portfolio and with the magnitude of the shareholder incentive provided to the utility.[47] We subtract resource costs from total resource benefits to calculate *net* resource benefits.

Net resource benefits are in the ~$310-380 million range if the prototypical utility implements the Moderate EE portfolio and increase to ~$510-620M for the Significant EE portfolio and ~$653-740M for the Aggressive EE portfolio for all incentive mechanisms except for Save-A-Watt (NC) (see Figure 21). Save-a-Watt (NC) costs so much relative to the resource benefits it generates that the portfolio of EE programs produce negative net resource benefits that get larger as the EE savings goals grow (e.g. -$67 million for the Moderate EE portfolio and -$298 million for the Aggressive EE portfolio). Save-A-Watt (NC) provides negative net resource benefits in part because of our assumption that customers pay for 50% of incremental measure costs. From a societal perspective, it is very difficult for Save-A-Watt (NC) to provide net resource benefits, because, as proposed, it provides the prototypical utility with 90% of the avoided cost benefits in its revenue requirement plus our assumed customer cost contribution.

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benefits and costs directly attributable to a portfolio of EE programs implemented by the utility, it is common to look over the measure lifetime, not over some predefined planning horizon. We use this convention and report and calculate resource benefits metric for the full 11-year measure lifetime. For example, we assume that the portfolio of EE measures installed in 2008 produce resource benefits in the 2008 – 2018 period. Similarly, the resource benefits for EE programs implemented in 2009 produce resource benefits for their 11 year measure lifetime (i.e., 2009 – 2019). The pattern continues through the last year of EE programs, which are implemented in 2017 and whose effects are captured through 2027. We also assume that customers replace measures at the end of their useful lifetime with measures of comparable efficiency (either because they are required by standards or are common practice).

[46] Resource benefits are comprised of three avoided cost categories: energy, generation capacity, and transmission & distribution capacity. All three are estimated from avoided cost forecasts strictly over the initial lifetime of the installed measures (see section 3.2). Although environmental externality benefits (e.g., reduced NOx, SOx, and particulates) may be included as resource benefits from a societal perspective, we took a conservative approach and excluded them. Had these environmental externalities been included, total resource benefits would have increased by less than 10% using the default monetized emission cost levels in the NAPEE Benefits Calculator. When assessing the utility's actual reduction in its revenue requirement (i.e. actual savings) as reported in Figure 14, we chose to include these environmental benefits because to the degree that energy efficiency can reduce NOx, SOx, and other environmental hazards, the utility's environmental compliance budgets will be reduced and these savings are likely to be passed on to customers at the next rate case.

[47] We include shareholder incentives in calculating resource costs assuming that the utility would not have undertaken the portfolio of EE measures without the shareholder incentive. However, we do not include the costs associated with an explicit and separate decoupling mechanism (e.g., the RPC decoupling mechanism) nor lost revenue recovery mechanism (e.g., as in Save-a-Watt (OH)) in estimating Net Resource Benefits. Both Save-a-Watt mechanisms integrate directly or indirectly the recovery of fixed costs; and thus we have chosen to include in the resource costs the total cost (i.e., revenue requirement) of the mechanism.

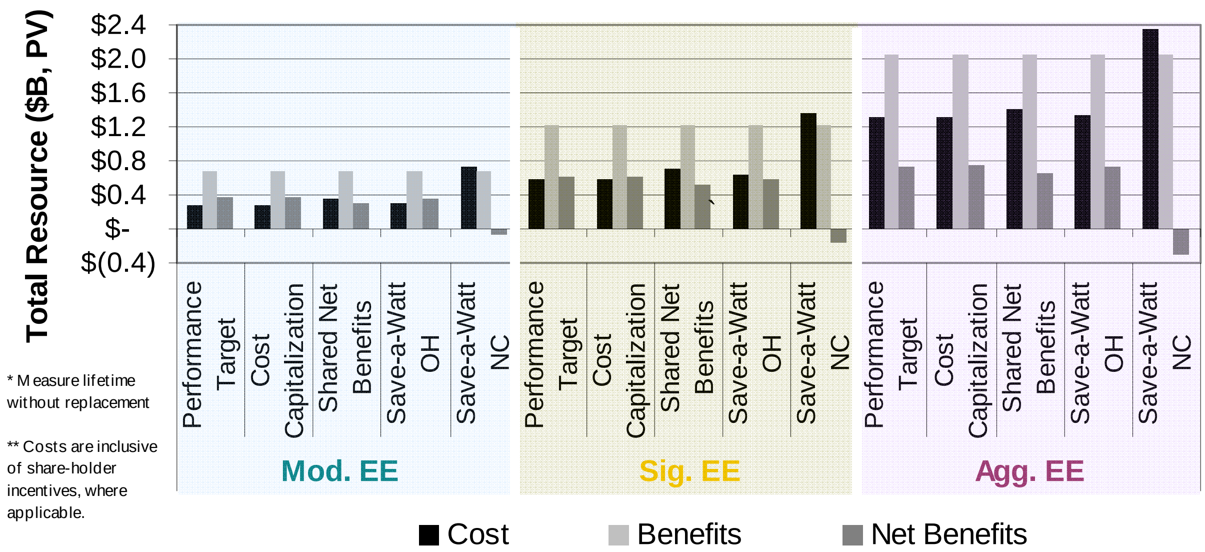


**Figure 21. Total resource benefits and costs of alternative energy efficiency portfolios**

For regulators, the joint application of mechanisms that address "lost revenues" and positive financial incentives requires an assessment of equity and fairness issues, such as the share of net resource benefits provided to customers vs. shareholders and whether a shareholder incentive and decoupling mechanism provide a fair return on investment to the utility. In Table 3, we show the five incentive mechanisms expressed in terms of the combined cost of the lost revenue recovery and shareholder incentive mechanisms as a percent of program cost and ratepayer share of net resource benefits for the three EE portfolios. We would highlight the following results.

First, as noted above, the cost of the decoupling mechanism is relatively small in comparison to the incentive payment produced under the Performance Target, Shared Net Benefits and Cost Capitalization mechanisms. So when combined together, the cost to ratepayers of the three incentive mechanisms plus decoupling, is 6 to 10 percentage points higher (expressed as a percent of total program budgets), than if the shareholder incentive mechanisms were implemented in isolation (see Table 2 to compare). In addition, the joint application of decoupling and any of the three incentive mechanisms reduces ratepayers' share of net resource benefits by less than 6 percentage points compared to when the incentive mechanisms are only implemented (see Table 2 to compare).

Second, the Save-A-Watt (NC) mechanisms, as designed, would provide an earnings opportunity for the utility that represents a very high share of program costs. For example, the mechanism's revenue requirement exceeds program costs by 46% to 192%.

Third, the ratepayer share of net benefits is relatively high (70-90%) for our Performance Target, Cost Capitalization, Shared Net Benefits and Save-A-Watt (OH) mechanism under any of the EE portfolios. In contrast, the Save-a-Watt (NC) mechanism provides all of the net resource benefits, and then some, to shareholders given the proposed design of Save-a-Watt (NC) (i.e., utility receives 90% of avoided cost benefits) and our assumptions about customer cost contribution for energy efficiency measures.[48]

**Table 3. Metrics used to assess the cost and fairness of jointly implementing decoupling and utility shareholder incentives**

| | Pre-Tax Incentive as % of Program Cost | | | Ratepayer Share of Net Benefits | | |
|---|---|---|---|---|---|---|
| **Incentive Mechanism** | **Mod. EE** | **Sig. EE** | **Agg. EE** | **Mod. EE** | **Sig. EE** | **Agg. EE** |
| Performance Target | 26% | 25% | 23% | 90% | 88% | 79% |
| Cost Capitalization | 24% | 23% | 21% | 90% | 89% | 80% |
| Shared Net Benefits | 70% | 58% | 33% | 72% | 72% | 70% |
| Save-a-Watt OH | 44% | 39% | 27% | 83% | 81% | 75% |
| Save-a-Watt NC | 292% | 251% | 146% | -16% | -23% | -35% |

## 3.5 Designing Shareholder Incentives to achieve and balance specific policy goals

Thus far, we have set the earnings basis for each of the five incentive mechanisms at levels that are commonly observed in practice in one or more states or proposed by a utility (in the case of the Save-A-Watt NC mechanism). Our analysis suggests that results for each incentive mechanism are strongly influenced by our choices with respect to earnings basis (e.g. share of net benefits, % of program costs awarded for achieving a performance target, equity kicker for Cost Capitalization). In this section, we adopt a different approach and instead take the perspective of a regulatory commission that is interested in designing shareholder incentives which focus on the end results that are of most interest to ratepayers and shareholders. Specifically, the PUC's policy goals are to capture a significant portion of the net resource benefits of energy efficiency for ratepayers while developing a sustainable business model for the utility to aggressively pursue energy efficiency, which the PUC defines as a specified basis point increase in its after-tax ROE compared to a BAU case without energy efficiency. The PUC is also interested in assessing the cost of each incentive mechanism relative to the EE budget necessary to achieve the desired level of savings. An important by-product of this approach is that it potentially sets an upper limit on the earnings impacts of a shareholder incentive mechanism, which may be important to certain stakeholders.

One way to approach this design problem would be to define a specific desired, but maximum, increase in the utility's return on equity that would be considered reasonable while also setting a desired, but minimum, goal for ratepayer retention of net resource benefits. Conceptually, it is clear that the larger the cost of the shareholder incentive, the greater the increase in a utility's ROE but the lesser net resource benefits will remain for ratepayers. The PUC wants to understand if it is possible, given the cost and benefits associated with all three EE portfolios under consideration, to design a shareholder incentive mechanism that accomplishes these goals at various savings target levels.

Suppose a regulatory commission believes that the goal of an incentive mechanism should be to provide ratepayers with at least 80% of the net resource benefits while increasing a utility's after-tax return-on-equity by a maximum of 20 basis points compared to the BAU No-EE case. The

[48] Net benefits are negative for this mechanism because the proposed Save-A-Watt tariff (NC) implicitly recovers "lost revenues" and this is included as a cost, because we can not break out this element separately.

tradeoff between ratepayer and shareholder benefits associated with the Performance Target, Shared Net Benefits and Save-a-Watt (NC) are shown in Figure 22.[49] The figure illustrates that under the Moderate EE portfolio, the utility can not achieve a 20 basis point improvement in its ROE if it implements the Moderate EE portfolio without receiving a much larger share of the net resource benefits (i.e., the utility must receive 30% of net resource benefits to achieve a 20 basis point increase in ROE). This would result in ratepayers receiving less than the 80% share of net resource benefits set forth by the PUC. If the ratepayer share of net benefits is considered as the more important constraint, then shareholder incentives would either not be provided to the utility in the Moderate EE case or the ROE target increase level would be reduced (e.g. 5-10 basis points). In contrast, if the utility achieves the savings targets in the Significant and Aggressive EE portfolios, a mechanism can be constructed whereby ratepayers and shareholders both receive their "fair share" of the benefits. If the utility achieves the desired 1% reduction in annual retail sales in the Significant EE portfolio, then the utility's ROE increases by 20 basis points while ratepayers retains exactly 80% of the net resource benefits. Should the utility achieve the Aggressive EE portfolio savings target, then ratepayers could receive an additional 2% of net resource benefits, retaining 82% in total, while still providing the utility with a 20 basis point improvement in its after-tax ROE from a shareholder incentive mechanism.

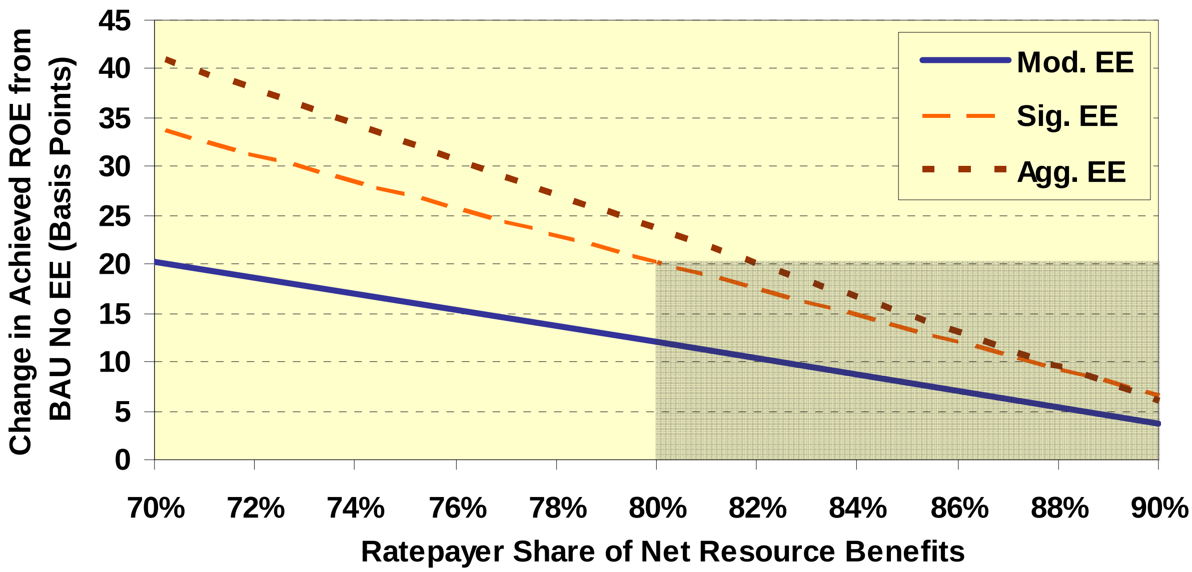


**Figure 22. Tradeoff between ratepayer and shareholder benefits for alternative EE portfolios with a Performance Target, Shared Net Benefits, and Save-a-Watt (NC) mechanism**

Regulators and other stakeholders are also interested in the cost of the shareholder incentives relative to the program costs associated with acquiring the desired level of energy efficiency

[49] Cost Capitalization requires additional equity to be issued; thus, the utility's achieved return on equity will be diluted for the same contribution to earnings as are provided by other shareholder incentive mechanisms. This aspect of the Cost Capitalization mechanism makes comparisons across different shareholder incentive mechanisms with respect to improvements in ROE more challenging. See Appendix F for detailed discussion of designing a Cost Capitalization incentive mechanism that balances these policy goals. We also exclude the Save-a-Watt Ohio mechanism from this aspect of the analysis because the mechanism has several different design features (i.e., share of gross resource benefits, lost fixed cost recovery time period) that make construction of comparable mechanisms to Performance Target, Shared Net Benefits, and Save-a-Watt NC challenging.

savings. In the case of the Significant EE portfolio, the incentive mechanism that meets all the criteria laid out by the regulatory body will cost ratepayers an additional 41% of the existing budget for these programs (see Table 4). Should the savings level increase to that of the Aggressive portfolio, the incentive as a proportion of total program costs would increase EE program costs by 19%.

Two of the three incentive mechanisms that meet our PUC's illustrative policy goals criteria are substantively different than the original designs applied in sections 3.4 (see Table 4).[50] For Shared Net Benefits mechanism, the utility's share of net benefits (which is the earnings basis) does not change much between the Significant and Aggressive EE portfolios (11-12%) and turns out to be roughly comparable to the original design of our Shared Net Benefits mechanism (15%).[51] In contrast, for the Performance Target mechanism, in order for the utility's ROE to increase by up to 20 basis points, the earnings basis would have to be adjusted downward from 25% to 12% of program costs if savings targets were increased from 1% to 2%. If regulators do not adjust the earnings basis for the Performance Target mechanism with the level of achieved savings, the utility is likely to substantially over-earn and receive much more than was originally deemed their "fair share" of the benefits. Finally, it is important to note that the earnings basis for the Save-a-Watt NC mechanism ranges between 36%-44% of the avoided cost benefits for the Significant and Aggressive EE portfolio, which is substantially lower than Duke Carolina's proposed 90% level.

**Table 4. Key Metrics and Design Criteria for Desired Incentive Mechanism**

| | Ratepayer Share of Net Resource Benefits | Change in After-Tax ROE from BAU No EE (Basis Points) | Incentive as % of Total EE Program Costs | Shareholder Incentive Mechanism Earnings Basis Level | | |
|---|---|---|---|---|---|---|
| | | | | **Performance Target** | **Shared Net Benefits** | **Save-a-Watt NC (Revised)** |
| *Earnings Basis* | | | | *% of Program Cost* | *Utility % of Net Benefits* | *% of Avoided Costs* |
| *Original Design* | | | | *10.0%* | *15.0%* | *90.0%* |
| Mod. EE | N/A | N/A | N/A | N/A | N/A | N/A |
| Sig. EE | 80% | 20 | 41% | 25.3% | 12.4% | 36.1% |
| Agg. EE | 82% | 20 | 19% | 12.1% | 11.2% | 43.7% |

[50] Given the results in **Error! Reference source not found.Error! Reference source not found.**, we defined a minimum savings target that must be achieved (1% savings of retail sales) in order for the utility to be eligible for shareholder incentives because neither party (i.e. shareholders and ratepayers) could be assured that they would receive their pre-determined fair share of the benefits.

[51] Because the net resource benefits are effectively monetized and converted into increased earnings for the utility via the shareholder incentive, there are now three parties that must share the net resource benefits: shareholders, ratepayers and the government by way of taxes. This explains why the earnings basis for this mechanism when added to the share of net resource benefits retained by ratepayers is less than 100%.

# 4. Discussion

In Chapter 3, we described and analyzed the financial impacts on utility shareholders and customers of increased energy efficiency efforts without and with decoupling and shareholder incentive mechanisms for a prototypical Southwest utility. That analysis supports the findings that:

- Aggressive and sustained energy efficiency can produce significant resource benefits at relatively low cost to society and utility customers. However, aggressive and sustained energy efficiency efforts will adversely impact utility shareholder interests by increasing the risk of lost earnings between rate cases and decreasing the available earnings opportunities over time.
- Introducing a decoupling mechanism can remove a short-run financial disincentive to energy efficiency by improving the ability of a utility to earn its authorized rate of return between rate cases. Shareholder incentives, while also potentially addressing this short-run disincentive, can improve the utility's longer term business case for energy efficiency by providing the opportunity to earn on such efforts to increase shareholder wealth.

In this chapter, we discuss policy issues that relate to the broader question of the need for and/or the defining features of sustainable business models for implementing large-scale ratepayer-funded energy efficiency programs over the long term. Specifically, we examine issues that a regulator must consider when deciding whether to authorize a decoupling and/or shareholder incentive mechanism for energy efficiency:

- Is the underlying need and rationale for decoupling and shareholder incentive mechanisms apparent? Are there additional barriers to increased energy efficiency because of different interests between utility shareholders and utility management as well as customers? To what extent could the expected benefits from increased energy efficiency efforts have occurred anyway without the use of a decoupling and/or shareholder incentive mechanism?
- Is full decoupling always necessary or are there effective alternatives to address the utility's interest in earning or exceeding its authorized return by increasing sales and avoiding lost earnings due to energy efficiency efforts?;
- If shareholder incentives are deemed appropriate, how much is enough and what level represents a fair balance between customer and shareholder interests?; and,
- Are there effective alternatives to the use of shareholders incentives to better align utility and public interests?

Our financial analysis does not provide clear answers to these important policy questions, but does help by offering some insight into the nature and extent of the financial disincentives for utilities to pursue aggressive and sustained energy efficiency efforts.

## 4.1 Utility Management Behavior and the Potential Agency Problem

Utility management has a fiduciary obligation to protect the interests of utility shareholders and to seek maximum returns on their behalf. Thus, management would be expected to be concerned about the potential for both short- and long-term lost earnings, especially when sustained energy efficiency efforts are undertaken. However, utility management may also have additional, distinct concerns about increased energy efficiency efforts beyond those held in common with shareholders. Utility managers may be concerned that a significant increase in energy efficiency efforts will adversely raise rates while skewing the appropriate allocation and management of scarce resources, time, and attention within the utility by dedicating such resources to tasks that provide no meaningful up-side over time in lieu of focusing such resources on “profit centers” within the utility. Utility managers may also believe that higher salaries and benefits, prestige, opportunity for advancement, and the desire to be part of a growing, dynamic organization can only be met by a “larger” sized utility characterized by increasing gross revenues based on real physical assets. In some cases, the compensation systems of utility managers may provide a personal incentive to focus on short-term rather than longer-term earnings and stock market prices. Furthermore, resource decisions are made by management; these large capital investment decisions have traditionally provided the only means for a regulated utility to increase allowed shareholder returns and/or meet distinct management objectives. This view could provide an important incentive for management to pursue more risky capital investments that may ultimately have an adverse effect on shareholder wealth rather than to opt for energy efficiency resources, which may be perceived by management as an uncertain means to meet utility service needs and does not provide an opportunity to advance management’s objectives.

These “agency” concerns of potentially different interests between utility shareholders and management should not be ignored in assessing the potential impediments to increased energy efficiency efforts or in the design of performance incentive mechanisms. Given these issues, it may make sense to explore incentive mechanisms that make increased energy efficiency a “profit center” for both utility shareholders and managers. This energy efficiency “profit center” has to be of sufficient size so that utility managers directing energy efficiency programs will be able to obtain the necessary staffing, support and corporate resources from senior utility management to have a reasonable chance of achieving the established energy efficiency goals.[52] The additional net earnings generated by energy efficiency activities must sufficiently increase shareholder wealth to be worth the time, use of resources and potential risk for utility shareholders and management to earn them and ideally also address some distinct objectives that motivate utility management.

### 4.2 Assessing the importance and need for full decoupling and shareholder incentives

Energy efficiency efforts can provide substantial value to customers but are typically detrimental to utility shareholder and management interests (as demonstrated in section 3). State regulators and legislators may consider alternative policy approaches to promoting ratepayer-funded energy efficiency: (1) use a decoupling and/or shareholder incentive mechanism that seeks to increase the value of energy efficiency to utility shareholders and/or (2) rely on regulatory directives or legislative mandates such as an Energy Efficiency Resource Standard (EERS) that require utilities to implement energy efficiency efforts, or (3) rely on some entity other than a regulated utility to achieve the desired results.

[52] For example, California utilities often cite this as the reason their energy efficiency programs have ample staff and corporate resources.

### 4.2.1 Metric for Assessing the Value of Full Decoupling and Potential Alternatives

Decoupling is a means to prevent short term adverse impacts that limit a utility's ability to earn (or earn more than) its authorized rate of return. A primary goal of decoupling is to protect the utility against earnings attrition due to sales loss from energy efficiency efforts between rate cases.[53]

The potential value of a decoupling mechanism to utility shareholders and management depends primarily on two factors: (1) the potential or expected impact on earnings of "lost revenues" which are the product of the size, effectiveness and duration of energy efficiency efforts; the time between rate cases; and the probability that actual annual sales will equal estimated test year sales, and (2) the on-going relationship among utility sales, revenues, costs and customer growth between rate cases.[54] The first factor essentially focuses on the impact of the increased energy efficiency efforts, while the second factor encompasses all other factors that affect a utility's ability to earn its authorized return between rate cases. The interaction of these two factors typically shapes a utility's interest (or lack of interest) in full decoupling or some other way to offset these adverse earning impacts, such as a "lost revenue" clause or shareholder incentive mechanism.

Our modeling results illustrate the point that the value of decoupling to utilities and the type of decoupling (full, partial or limited) is likely to be situational depending on the above two factors. The situational value of decoupling is evident for utilities that face very different circumstances than our prototypical Southwest utility. The greater the probability that actual sales will equal or exceed estimated test year sales, the more that revenue growth exceeds expense growth between rate cases, the more limited the energy efficiency effort and the more limited the period between rate cases, the less compelling that decoupling may seem necessary or desirable to a utility. However some form of decoupling such as a "lost revenues" clause tied directly to the impact of energy efficiency efforts (or a shareholder incentive mechanism) may seem attractive because it allows for the recovery of lost earnings due to energy efficiency while allowing a utility to maintain its through-put incentive to make as many sales as possible between rate cases to earn or exceed its authorized return. A full decoupling mechanism under these scenarios would be unattractive by eliminating the ability to increase earnings by increasing sales between rate cases – this is the essence of the throughput incentive issue.

In contrast, a full decoupling mechanism will seem much more attractive to a utility like our hypothetical southwest utility that has less robust opportunities to achieve or earn more than their authorized return between rate cases from increased sales, particularly if large-scale energy efficiency efforts are implemented. The same is true for a utility that perceives that its test year sales have or will be set at levels that significantly exceed the utility's expectation for actual sales during the period between rate cases.

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[53] It is worth noting that these efforts are not limited to utility-administered energy efficiency programs as savings efforts by an independent third party administrator will create the same concern for a utility.

[54] Use of decoupling may also reduce a utility's regulatory overhead by extending the time between rate proceedings.

In assessing the need or desirability of a decoupling mechanism, stakeholders should consider the effect of decoupling mechanism on a utility's incentive to pursue cost-effective energy efficiency, issues of changing the utility's risk profile, the potential need to reduce the authorized return or make some financial adjustment, and the possibility of increased rate volatility for customers. But, if policymakers and stakeholders are interested in establishing sustainable utility business models for energy efficiency, then the important metric ought to be whether the alternatives to full decoupling would be equally effective in addressing the utility's short-run disincentive to reduce sales reflected in lost sales margin and its incentive to increase sales embodied in the throughput incentive that undermines the value of the energy efficiency benefits achieved.

#### 4.2.2 Metric to Assess the Value of Shareholder Incentives

The basic metric of the sufficiency of a shareholder incentive for energy efficiency is whether the reward is valuable enough to the utility given the resources, costs and risks to attain it as well as the value of the alternative earnings opportunities that may be foregone. Based on the practices of U.S. utilities over several decades, we believe that many utilities will choose other resource options that have a greater financial value to utility shareholders (but may produce lower societal benefits than energy efficiency), unless a stable, long-term regulatory policy framework is in place that reduces the divergence between the financial value of energy efficiency to utility shareholders and the financial value of traditional supply-side investments.

Our analysis in Chapter 3 indicates that the more aggressive and sustained the energy efficiency efforts, the greater the potential financial loss to utility shareholders and management, especially from the loss of future earnings opportunities. It is important to understand and consider the effect of aggressive energy efficiency efforts over time because there are specific circumstances when energy efficiency, even without the ability to earn a reward, may be attractive to a utility. That situation is exemplified by what transpired during the 1970s in California when the high cost of capital and the extreme uncertainty of forecasting sales made the construction of large-scale generating units quite risky because of the potential adverse impact on the utility's financial health. In this circumstance, energy efficiency and third-party owned, private power helped the California utilities defer the need to build until market conditions become more favorable. However, even in these circumstances, there may be a value in allowing a utility to earn on its energy efficiency efforts to raise its attractiveness in relation to other available resource options

It is also useful to acknowledge that increased energy efficiency may not always significantly diminish the opportunities for some utilities to earn on future investments in the near- to mid-future. For example, a utility's opportunity to earn on new "smart grid" investments may or may not be primarily justified or driven by their ability to help reduce the rate of usage growth. Similarly, some utilities are likely to face requirements to limit carbon emissions and/or face additional uncertainties in predicting future loads due to new end-uses (e.g., penetration of hybrid electric vehicles). In this situation, utilities may perceive that large-scale energy efficiency, at least for some limited period of time, can help reduce the risks of undertaking such substantial investment to meet these needs.

Even considering these potential exceptions, because energy efficiency efforts typically have adverse impacts on a utility's financial circumstances, policy mechanisms that increase the financial value of energy efficiency to utility stockholders and management are likely necessary if utilities are going to voluntarily pursue large-scale energy efficiency on a sustained basis. The ultimate metric will be whether the incentives are adequate to blunt this disincentive while representing an equitable sharing of benefits, costs and risks with utility customers.

## 4.3 How Much is Enough for a Shareholder Incentive?

The justification for a shareholder incentive mechanism still leaves open the question of how much does a utility need as an incentive to support large-scale, sustained energy efficiency efforts. There have been at least three primary alternative approaches that have been proposed in various regulatory forums where shareholder incentives for energy efficiency have been discussed that may help bound what is likely required and/or provided.

### 4.3.1 The ability to earn at the utility's return on equity

Advocates of this approach argue that utilities should be allowed to earn the same rate of return on energy efficiency expenditures as they would on supply-side investments. There are three main reasons why this "comparability" approach has generally not been viewed as effective as an incentive. First, allowing a utility to earn a return and capitalize energy efficiency expenses at its authorized rate of return has typically not provided sufficient earnings to overcome "lost revenues" from reduced sales and also provide a positive incentive to pursue large-scale energy efficiency efforts.[55] In contrast, Nevada's "bonus" return of 500 basis points for energy efficiency expenditures is intended to motivate utility management and Nevada utilities have indicated that they support this approach.

Second, the value of increased net earnings to a utility from additional investment depends on its impact on the utility's shareholder wealth (i.e. an increased overall return reflected by increased earnings per share). Because rate of return is only one factor affecting the increase in total return, a utility will favor investment opportunities that provide the largest increment of additional net earnings to increase existing shareholder wealth. For the same return, the largest project (assuming equal risk and timing of the return) will be the most valuable (i.e. a supply-side investment which is by definition larger than energy efficiency expenditures that would avoid or defer this investment).[56]

Third, if new equity shares must be issued to support the cost capitalization mechanism, there will be a need to generate even greater earnings to be of interest to the utility (see section 3.4.3). For these reasons, a mechanism that seeks to achieve an adequate incentive for increased energy

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[55] According to Jensen (2007) and Reid (1988), during the 1980s, a number of states (e.g. Oregon, Idaho, Washington, Montana, and Wisconsin) allowed utilities to capitalize energy efficiency-related investments at their authorized rate of return or a bonus ROE. Although this approach remains "on the books" in several states, it is seldom used and has fallen from favor.

[56] We recognize that each supply-side option is unlikely to have the same risk profile. For example, traditional coal plants may have an increasing risk profile because of future but now unknown carbon-related regulatory costs. Nuclear power may have high construction cost risks while gas-fired generation has significant fuel cost risk – although customers typically bear the fuel price risk (rather than the utility).

efficiency must do more than provide a comparable rate of return on supply-side and energy efficiency "investments."

#### 4.3.2 The ability to earn a fair return on investment on a project-specific basis

Advocates of this approach argue that shareholder incentives for utilities should be set at levels that are comparable to what an independent third-party administrator would need in terms of an earnings opportunity to undertake the desired energy efficiency effort. Supporters of this approach argue that the financial incentives required by a non-utility, energy efficiency program administrator to achieve the states' desired energy efficiency savings targets (and other policy objectives) represents a benchmark, and perhaps a ceiling, that can be used to establish a reasonable range for the level of a financial incentive for a utility.[57] Incentives above that level would be viewed as unnecessary, and therefore excessive, because the same result could be achieved for a lower cost through the use of a third party administrator.

There are several important issues raised by this potential approach to defining an appropriate level for a shareholder incentive. A threshold issue is the viability or interest of state policymakers and regulators in creating a third party administrator in lieu of the utility to pursue energy efficiency objectives; these issues are discussed in more detail in section 4.4. In our specific context, the issue is whether a return that would be adequate for a non-utility party would also be adequate to provide an adequate incentive to a utility to pursue large-scale, sustained energy efficiency efforts.

We believe that the answer to this question is an empirical one. For a utility, the bottom-line question is whether the available increase in shareholder wealth to undertake a specific resource option is of sufficient size to be worth the costs and risks of the effort (and better than the opportunity cost of using those resources elsewhere). This impact depends on the project's earnings impact on the utility's overall return, not on the energy efficiency project's return on equity. Thus, it is unclear whether the earnings and return requirement of a third party would meet a utility's financial threshold. For example, a for-profit (or non-profit) firm that is far smaller than a utility may be willing to administer an energy efficiency portfolio for a level of increased earnings that a larger utility might find of very limited value given its far larger accumulated earnings.

#### 4.3.3 "Supply-side comparability:" Comparable Financial Value from Energy Efficiency and Avoided Generation Plant

Advocates of this approach argue that the utility should be allowed the opportunity to earn a comparable net present value of earnings on its energy efficiency effort as it would have on the plant that the energy efficiency avoids in order for it to be truly indifferent between building new generation plant and undertaking energy efficiency. In essence, Duke Energy made this type of argument in support of its proposed Save-A-Watt (NC) mechanism. Conceptually, the approach

[57] Even non-profit third-party EE administrators can earn a "profit" through fully loaded labor rates or other contract provisions and have signed contracts that provide opportunities to earn financial incentives for superior performance. In several states (Vermont, Wisconsin), these performance incentives represent ~2-4% of total program costs for achievement of specified goals.

is analogous to the idea of mutually exclusive projects under capital budgeting principles. Under those principles, the utility would choose that mutually exclusive project that, after adjusting for risk and timing of cash flows, provides the largest net present value addition to shareholder value (i.e. increased earnings per share).

The “supply-side comparability” approach raises several issues. First, while the utility perspective of “mutually exclusive investments” is understandable, that is not the perspective of state regulators or utility customers. The latter parties’ perspective is the choice of the least cost or best expected value resource to meet customer needs. This may translate into a preference for resource portfolios that include large-scale, cost-effective energy efficiency programs. Regulators should not choose the more costly resource if, on a risk-adjusted basis, an adequate less costly resource is available. Under these circumstances, the utility does not have the option of making the more expensive investment and has no entitlement to the potential lost earnings from an investment that public policy would not sanction in the presence of a lower cost, adequate alternative. In essence, we argue that utility shareholders and managers’ options are somewhat constrained by its public interest obligations.

Policies in many states require selection and acquisition of resource portfolios that are lowest cost and/or “best value” to customers, thus, the relevant issue for regulators is whether the utility would be willing to pursue large-scale, cost-effective energy efficiency resources as an independent investment as long as a reasonable earnings opportunity is provided that will increase the utility’s overall return. Conversely, if the utility is unwilling to accept this regulatory standard, then it may be preferable or necessary to pursue a non-utility entity or some other way to achieve these objectives at a lower cost? We will explore this latter question in the next section.

Second, financial comparability even with mutually exclusive investments requires a consideration of the value of each investment given its relative risk, timing of earnings, size of the project on which earnings will be generated, need to issue additional equity shares, and the required cost of capital. The preferred project will be the one that results in the greatest increase in the firm’s overall shareholder wealth (i.e. provides the greatest increase in risk-adjusted net present value earnings per share to increase the firm’s overall return). Assessing financial comparability between supply-side and energy efficiency “investments” can not be determined only by calculating the earnings that the utility would have received if it had built the plant.

Third, “supply-side comparability” treats issues of equity and fairness to customers as more residual issues than primary considerations. Our modeling results suggest that the “supply-side comparability” standard may end up providing a substantial portion of the benefits to the utility (see section 3.4.3 results for Save-A-Watt NC). While it can be argued that the residual benefits received by ratepayers are better than if the utility had not been motivated to choose the energy efficiency option, this does not seem like a compelling argument when a more balanced sharing of net benefits from alternative approaches are available.

#### 4.3.4 Summary and Recommendations: How Much is Enough?

If a regulatory commission decides that ratepayer-funded EE programs are to be administered by utilities, we believe that the utility should be allowed to earn a level of incentive that provides an opportunity for a meaningful increase in utility shareholder wealth for successfully achieving aggressive and sustained energy efficiency efforts. The level of the incentive should be adequate to attract utility management attention to treat energy efficiency efforts as a valuable profit center and be valuable enough to induce utility management to employ the resources and attention needed to achieve such shareholder incentives over time. In reviewing the merits of incentive mechanism proposals, state regulators should also consider and address equity and fairness issues, such as the share of net resource benefits provided to customers versus shareholders and the potential impact of incentives on the overall level of energy efficiency program costs.

Drawing from the results of our modeling of a prototypical Southwest utility, we make the following observations on the issue of how much is enough in terms of shareholder incentives.

- The effective level of a shareholder incentive will be situational and depend on various factors such as the size of the energy efficiency effort and the risk to the utility under the shareholder incentive mechanism. There is no single number that will fit all situations. Thus, it is reasonable to expect that utilities that are just starting their energy efficiency efforts may need less of an incentive than utilities with a longer history of energy efficiency efforts and more aggressive savings targets. In evaluating alternative incentive mechanism proposals, state regulators should assess their potential impact on the utility's after-tax ROE. One approach is to provide utilities with an opportunity to achieve a meaningful increase in shareholder wealth (e.g., increase the utility's after-tax ROE by 10 to 20 basis points) that is linked to achieving specified energy efficiency policy goals (savings targets) and which balances ratepayer interests and concerns. This is essentially the approach described in section 3.4.
- Shareholder incentive mechanisms that significantly increase the costs of EE programs by garnering more of the savings for shareholders, and thereby reducing the value of EE to customers, will have more difficulty obtaining the support of customer and other stakeholder groups because of fairness and equity concerns. In our modeling (see Appendix F), we found that this situation occurred in the Moderate EE case where energy efficiency program costs were increased by 44-51% for incentive mechanisms that increased ROE by 10 basis points and by 74-81% for incentive mechanisms that increased ROE by 20 basis points (see Table F- 1). Thus, it may be appropriate to limit the availability of shareholder incentives for energy efficiency to situations in which the utility has committed to significant energy efficiency goals that will produce significant net benefits to ratepayers and society. Another option is to link the earnings basis of a shareholder incentive mechanism to the relative aggressiveness of the savings target through the use of a sliding scale for the earnings basis. This may help ensure that the overall shareholder incentive value will both be adequate in value to utility shareholders, but fair in relation to the value received by utility customers and the public.
- The allocation of benefits, costs and risks among utility shareholders and ratepayers is another critical input to decisions on the design and appropriate level of shareholder incentives. In our modeling of incentive mechanisms at a prototypical southwest utility, we found that Performance Target, Cost Capitalization and Shared Net Benefits provided a far greater share of net benefits to ratepayers than Save-A-Watt (NC) (see Table 3). We also found that the design (earnings basis) of Save-A-Watt (NC) would have to be significantly changed (i.e. reduced to 30-40% of avoided cost rather than 90% of avoided

generation costs) in order for ratepayers to receive most of the net benefits. Customer groups are much more likely to support shareholder incentive mechanisms that allocate ~80-90% of the net resource benefits of energy efficiency to ratepayers than those which dilute those savings to significantly lower levels.

- More real world research into the importance of non-financial considerations for utility shareholders and management on acceptable shareholder incentives would be desirable.

## 4.4 Alternatives to Utility Shareholder Incentives

Policymakers are also increasingly considering other options to help attain increased energy efficiency benefits for ratepayers. These include: (1) statutory or regulatory directives, such as the use of an Energy Efficiency Resource Standard (EERS) and (2) using non-utility entities to administer a portfolio of energy efficiency programs. Some advocates argue that using these options would be less costly ways than trying to re-align utility incentives through efforts such as decoupling and shareholder incentives.

### 4.4.1 Statutory or Regulatory Directives

In an Energy Efficiency Resource Standard (EERS), a state legislature or regulatory commission establishes a long-term energy savings target for utilities, which is typically defined as a specific percentage of their retail sales or projected load growth (Eldridge et al 2008). For example, a number of states have passed legislation (e.g., Minnesota, Connecticut, Colorado, New York, Illinois, Ohio, Maryland, Texas and Pennsylvania) that establish goals for utilities to reduce energy consumption through an EERS or includes energy efficiency as part of a renewable portfolio standard (e.g. Nevada, Hawaii, North Carolina). In some cases, the utility faces financial penalties if legislatively-mandated savings or energy reduction goals are not achieved.

The basic issue about the use of regulatory or legislative mandates is that neither approach changes the fundamental financial impacts on utility shareholders and management. Indeed, the more aggressive and sustained the savings sought under such directives, the greater the adverse impact on utility shareholders and management. The success or viability of such an approach over time is obviously not a matter that can be answered by financial modeling, but concerns the shaping of public policy over an extended period of time.

The viability of relying solely or primarily on legislative or regulatory directives that mandate utilities to aggressively pursue energy efficiency without the opportunity for financial benefit assumes a continuity of purpose in public policy and level of regulatory oversight that the actual historical boom and bust cycles of energy efficiency in the United States seem to belie. It also treats utilities as essentially passive actors in the process and implicitly discounts their ability over time to influence legislative or regulatory policy that they view as directly inimical to their fundamental financial interests. In this sense, it may be short-sighted to rely solely on a mandate; some states have adopted policies that include both energy efficiency resource standards along with either decoupling and/or shareholder incentive mechanisms (e.g. New York, Colorado, Minnesota).

### 4.4.2 Use of Non-Utility Parties as Energy Efficiency Program Administrators

A number of states (e.g., Vermont, Oregon, New York, Wisconsin) have chosen to have non-utility entities act as independent third-party administrators for their state's primary energy efficiency efforts or are in the process of implementing such an approach (e.g. Hawaii, Delaware, District of Columbia). These efforts have gone through a learning curve of their own, sometimes with unsuccessful results (e.g. California in the late 1990s). However, the EE program administrators in several of these states (VT, OR, NY, WI) have attained significant levels of savings at reasonable cost, which indicates that this approach can be a viable option. Some advocates maintain that relying on non-utility administrators that do not have financial disincentives to aggressive, sustained pursuit of energy efficiency is preferable to utility administration accompanied by decoupling and/or shareholder incentives. However, it should be noted that third party administration does not mitigate the adverse financial impacts of energy efficiency on utility shareholders and management, nor does it cure incentives to obstruct or obfuscate energy efficiency policy initiatives.

There are other pragmatic issues that also need to be considered in assessing the relative merits and viability of a third party administration option (Blumstein et al 2005). First, the move to third-party administration typically involved the enactment of adequate state enabling legislation and required the devotion of significant regulatory and stakeholder resources during the transition period. Second, the move to an independent non-utility third party administrator has been more successful in states that have had a long history of large-scale energy efficiency activity. Each of these states had a viable energy efficiency services infrastructure beyond just the utilities that provided a potential pool of qualified firms and human resources. Third, there may be significant differences among state regulators in their ability and willingness to oversee a traditional regulatory model built on regulated utility administration of an energy efficiency portfolio versus a transition to an independent, third-party administrator based on a contractual model with a non-regulated party.[58]

While we believe that additional discussion is warranted on models for energy efficiency administration that are most appropriate for states, it should be recognized that this is only likely to shift the nature and focus of how to address the adverse financial impacts of energy efficiency on utility shareholders and management.

## 4.5 Energy Efficiency Business Models: Conceptual Framework

In preceding sections of this chapter, we have highlighted several policy issues that relate to the broader question of the need for and defining features of sustainable business models for implementation of large-scale ratepayer-funded energy efficiency programs. Figure 23 provides a conceptual framework for state regulators that either want to significantly increase energy efficiency efforts or are responsible for implementing state (or possibly future Federal) legislation that establishes explicit (or implicit) aggressive savings goals (e.g., an Energy

[58] California, New Jersey and Wisconsin each encountered significant problems in dealing with state procurement and finance agencies and/or Attorney General's offices that had significant adverse consequences on the ability to transition to or create workable models of third-party administration of energy efficiency programs.

Efficiency Resource standard, statutes that require utilities or other EE program administrators to acquire all cost-effective energy efficiency).

At present, EERS are established and implemented at a state level, but it is possible that future federal legislation may include a separate national energy efficiency resource standard or energy efficiency resources may be included as part of a federal RPS statute. In most states, responsibility for achieving the EERS obligation has been placed on utilities (and/or other load serving entities). It is also possible to define compliance strategies for an EERS more broadly to include ratepayer-funded energy efficiency programs, building codes and appliance/equipment standards.

State regulators (or legislators) then must decide on the entity (or entities) that should administer ratepayer-funded energy efficiency programs: continue with utility administration or move to third-party administration either using an existing or newly created state agency or a non-profit or for-profit corporation. It is also possible for states to have more than one program administrator for energy efficiency with shared responsibility and specified goals (e.g. New York, Maryland, Illinois). Decisions regarding administrators of the portfolio of EE programs are really choices about the business model for energy efficiency in a state.

If a regulatory commission decides to continue with utility administration of energy efficiency, they must assess the extent to which the utility faces disincentives to aggressive pursuit of energy efficiency. This will depend on requirements such as those imposed by existing state statutes (e.g., EERS), existing ratemaking practices, the frequency of rate cases, cost recovery options, the utility’s business-as-usual resource plan, and state policies on ratebasing of generation by a regulated utility.

If a PUC concludes that significant disincentives to energy efficiency are present, a PUC should consider entertaining proposals that attempt to overcome these disincentives. Even if there is broad agreement that disincentives to energy efficiency should be addressed, there may be substantial disagreement among stakeholders as to the size and scope of these disincentives and the appropriate mechanism to address the problem. This point in the process is where the type of quantitative financial analysis of alternative ratemaking and incentive mechanisms that we have illustrated in this study can be particularly useful to a regulatory commission, utilities, and other stakeholders. The shareholder incentive mechanism proposed by the utility may be perceived by stakeholders and/or regulators as being excessive or conversely, alternatives proposed by customer and other stakeholder groups may be regarded as insufficient or inadequate to either overcome the utility’s financial disincentives to acquiring large-scale, energy efficiency resources over long time periods.

Ultimately, state regulators must decide on the appropriate ratemaking mechanism to address under-recovery of fixed costs due to reduced sales from energy efficiency (e.g. decoupling, lost revenue recovery mechanism) and/or the design of a shareholder incentive mechanism. If a regulatory commission concludes that the utility’s performance as an administrator or its commitment to energy efficiency primarily depends on approval of an unacceptably excessive shareholder incentive mechanism, then a PUC may decide that other third-party options for administering energy efficiency programs should be seriously considered. For those regulatory commissions that approve decoupling, lost revenue recovery and/or shareholder incentive mechanisms for utilities, these mechanisms should be periodically evaluated to assess their effectiveness in providing benefits to ratepayers, establishing an attractive business model for energy efficiency, and continued alignment with a state's policy objectives.

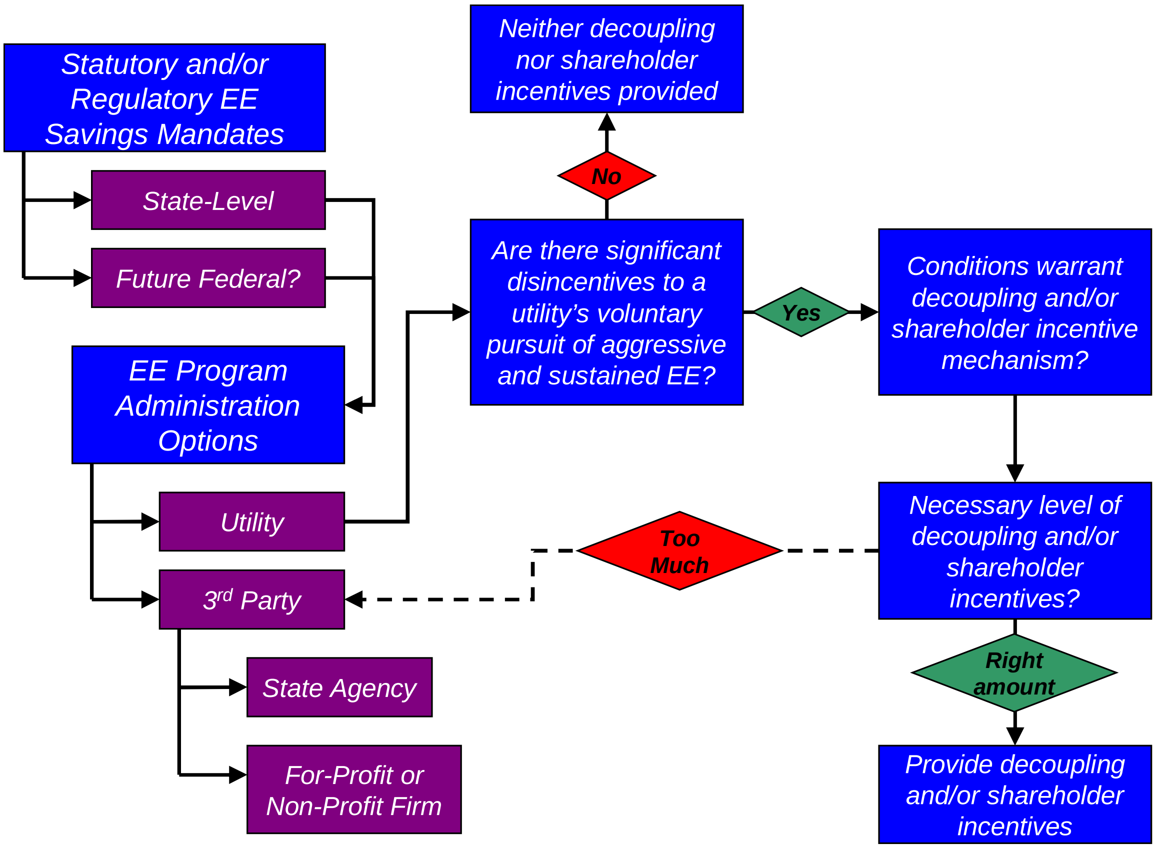


**Figure 23. Energy efficiency business model conceptual framework**

## 4.6 Conclusion: Aligning the Public Interest and the Interests of Utility Shareholders and Customers

We believe that successful "business models" for energy efficiency will depend primarily on the extent to which those models *accommodate, balance and align* the distinct interests of the utility, ratepayers and regulators in pursuit of the public interest. Under traditional regulation, there are fundamental financial barriers that hinder utilities from supporting large-scale, cost-effective, sustained energy efficiency efforts. Our analysis suggests that for energy efficiency efforts adequate in magnitude and duration to affect future resource options, there is a need for properly designed and administered decoupling and/or shareholder incentive mechanisms that better accommodate, balance and align private utility shareholder, management and customer interests to achieve the public interest. This is especially critical if one perceives that energy efficiency has a crucial role to play in addressing the problems of sharply increasing future utility costs and the expected impact of and cost to effectively mitigate global warming and that utilities (either as portfolio administrators or as motivated supporters of such efforts) can play an important role in the attainment of those objectives.

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# Appendix A. Development of Prototypical Southwest Utility

The Benefits Calculator requires specific information to characterize a utility for simulation purposes. The spreadsheet-based model requires initial year values for various characteristics of the utility (e.g., number of customers, annual electric sales, peak demand, average retail rate, production costs, rate base assets, capital expenditure and O&M budgets) as well as annual growth factors over the study time horizon.[59] Information on the utility's financial structure is also required including debt cost, outstanding equity, and authorized return on equity. This information is used to construct an initial picture of the financial health of the utility and determine how the growth of different cost components and changes in revenue collection impacts utility finances over time.

## A.1 Background research on Southwest Utilities

We developed a prototypical southwest utility drawing primarily from information on Arizona Public Service (APS) and Nevada Power Company (NPC). Financial and other data were collected from several sources including FERC Form 1, annual financial reports and their associated statistical supplements, the most recent general rate case filings, as well as direct utility staff input when available. Initially, we input utility characteristics and financial information on APS and NPC into the Benefits Calculator in order to test whether the average retail rates in the initial years produced by the Benefits Calculator were comparable to the utility's current retail rates.

Arizona Public Service does not produce publicly available forecasts, such as those found in an integrated resource plan (IRP), so we utilized recent historical information to help inform what the future might look like. Over the last five years, customers in APS service territory have grown by 3.8%/year, retail sales by 3.6%/year and peak demand by 5.5%/year according to their 2006 annual report (PWCC, 2007). Nevada Power's IRP indicates the number of customers in the service territory is expected to increase by 5.0%/year, retail sales rise by 2.0%/year and peak demand grow by 2.1%/year (NPC, 2006).

The fuel mix is also very different across the two utilities (see Figure A-1), with APS having a nuclear asset that provides 16.5% of its peak demand needs, while Nevada Power relies on native owned and operated renewable energy for 9% of its power requirements.[60] Both APS and Nevada rely heavily upon power purchase agreements to serve their peak demand and electricity needs.

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[59] The assumption implied by this input is that the growth rate for each data element is constant over the entire analysis period. The growth rates are unable to reflect any differences in short-term and long-term trends.

[60] The different fuels identified represent the proportion of peak demand served by utility-owned and operated supply resources that utilize that fuel, the obvious exception being purchased power. Within this report, renewable generation resources include existing hydroelectric power plants.

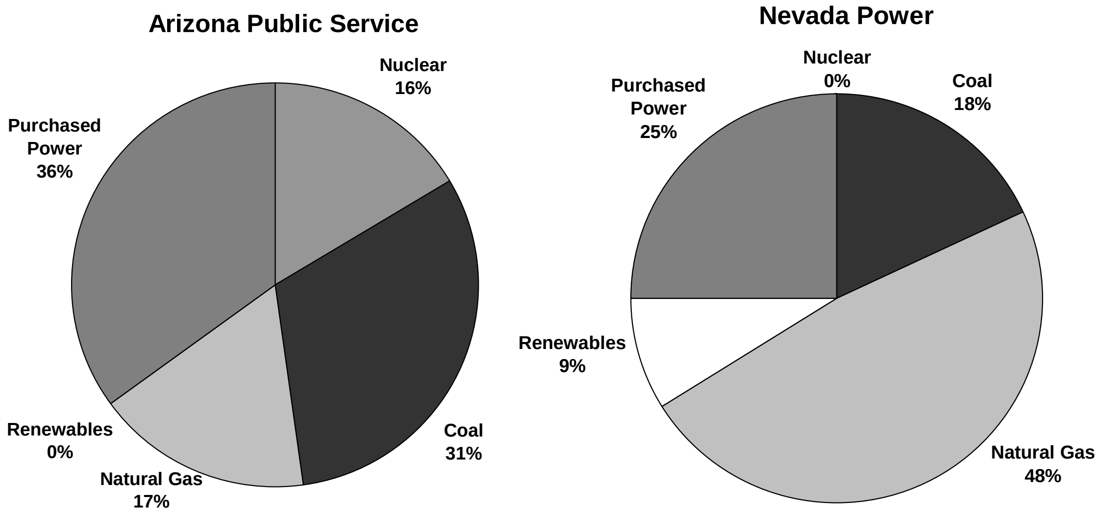



**Figure A-1. Resource requirements to meet peak demand for Southwestern utilities**

FERC Form 1 and the company's own annual reports provided insight into their current level and historical growth of O&M budgets, rate base assets, and capital structure. Using these values, along with the physical system data collected for Arizona Public Service and Nevada Power Company, it was possible to construct a complete characterization of the two utilities from the Benefits Calculator standpoint. The resulting first year revenue requirements are displayed graphically in Figure A-2. Previously, APS made substantial capital investments that are still on its books, as evidenced by the larger proportion of the revenue requirement going to depreciation and return on rate base, while O&M costs account for a much smaller share of total costs for Nevada Power compared to APS (12% vs. 26%).

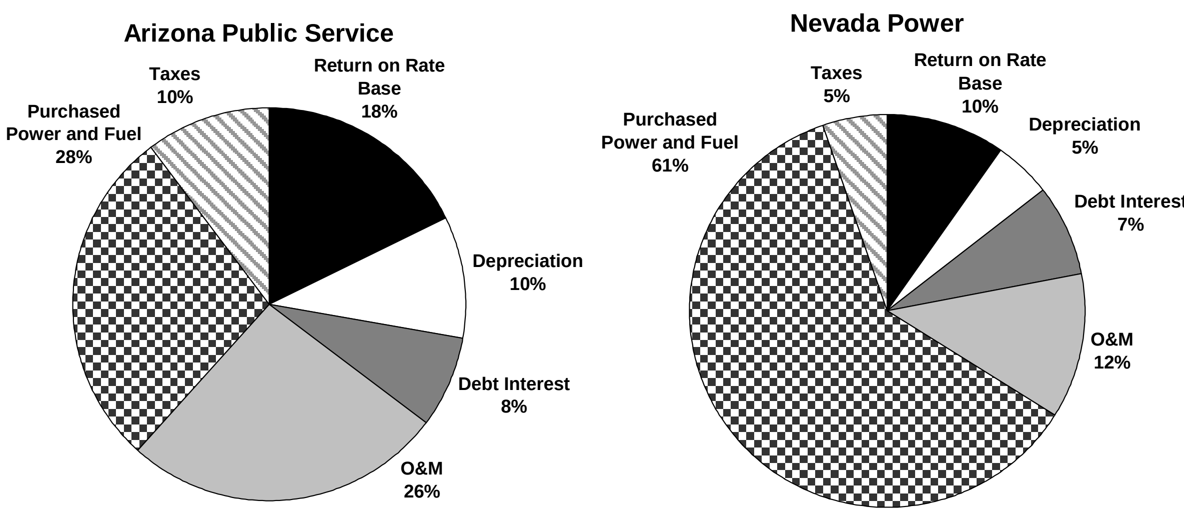



**Figure A-2. Revenue requirement for Southwestern utilities**

The APS data produced a retail rate (9.1¢/kWh) in the Benefits Calculator that nearly exactly matched the derived FERC Form 1 retail rate (9.0¢/kWh). For Nevada Power Company, the Benefits Calculated estimated an initial retail rate of 10.9 ¢/kWh compare to a retail rate of 9.8 ¢/kWh, based on FERC Form 1 data. This exercise was fruitful in that it showed how some manipulation of the data would be required when developing the prototypical utility in order to maintain internal consistency with desired first-year rate levels. Furthermore, it helped inform what reasonable levels might be expected for each major cost element in the revenue requirement (as illustrated in Figure A-2).

Given the diversity of values for key inputs across the two utilities, we decided to take mean values for the applicable data categories and growth rates, or normalize budget dollars by some common element (i.e., utility-operated generating capacity available at peak) in order to derive representative input values for our prototypical southwest utility. This latter method provided a reasonable proxy for the relative size of T&D capital expenditure and O&M budgets.

### A.2 Constructing the base case utility characterization

We assumed the prototypical southwest utility had annual retail sales of 25,000 GWh and an initial peak demand of 5,708 MW in 2008, which produced a load factor of 50%. Sales were forecasted to grow at a compound annual rate of 2.8%, while peak demand was expected to increase at a slightly faster rate of 2.9%/year (see Figure A-3). Note that the load factor decreases somewhat over time as peak demand grows faster than retail sales.

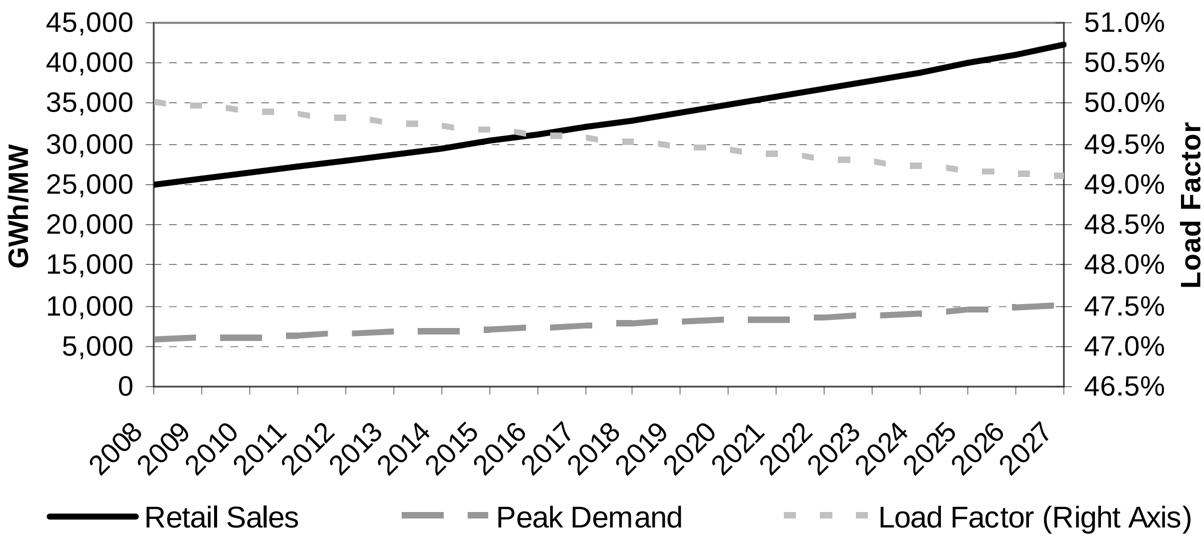
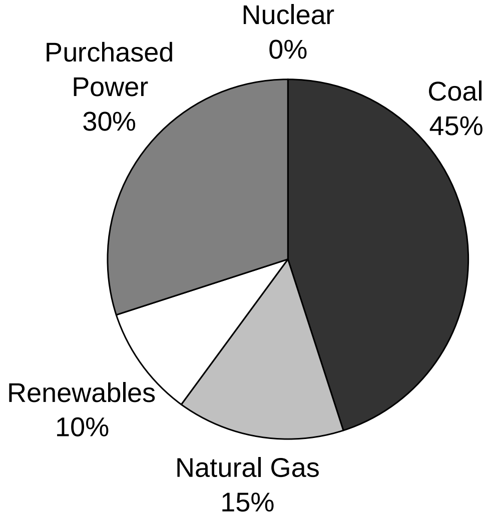



**Figure A-3. Forecasted retail sales, peak demand and load factor at prototypical Southwest utility**

The initial resource mix of our prototypical utility was derived in part to be representative of APS and Nevada Power (see Figure A-1), but was also driven by a desire for the prototypical utility to have a first year average retail rate of ~9 ¢/kWh, which is close to the mean retail rate in the southwest. We examined public forecasts of likely fuel costs for each resource type in the near-term, which, given a specific resource mix, was then used to generate a weighted average production cost to the utility, as well as capital expenditure and O&M budgets.[61] An iterative

[61] Ideally, without data and budget constraints, we would have fully characterized the entire fleet of native generation assets, including fuel type, heat rate, and likely retirement date, which would have produced a fuel cost and annual O&M budget for the existing portfolio of resources. With new, more efficient, resources coming on-line to either supplant or replace existing resources, the portfolio-level fuel cost would go down thereby reducing the

process over alternative resource mixes was then undertaken using the Benefits Calculator to achieve the revenue requirement that would yield a first year retail rate of 9.1¢/kWh (see Figure A-4).



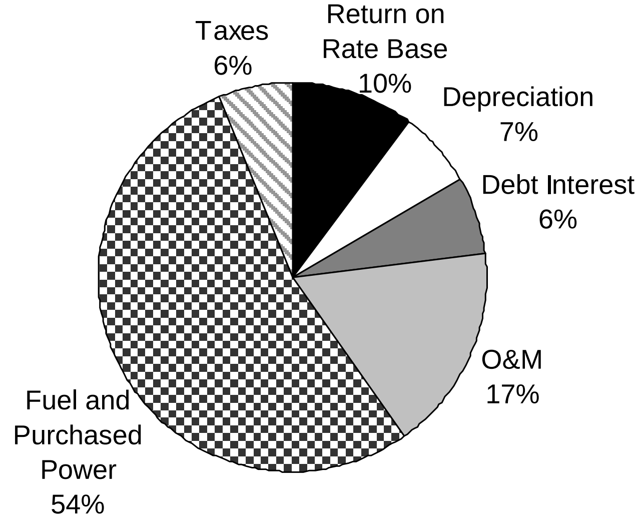




**Figure A-4. First-year resource mix and revenue requirement for prototypical Southwest utility**

We assumed that the prototypical utility has an annual transmission and distribution capital expenditure budget, absent expenses for generation investment, of $297 million, which is assumed to grow at an annual rate of 5%. The utility's assumed incremental investment in generation was intended to maintain the roughly 30% reliance on purchased power agreements, and was based primarily upon Nevada Power's most recent IRP, with limited additional input from resource plans of other utilities in the region, e.g., PacifiCorp, Public Service of Colorado, Northwestern Energy, Idaho Power (Barbose, et al. 2008). We also took into account renewable portfolio standard requirements enacted by various states and WGA Clean Energy Goals by assuming the utility had to meet 20% of its peak demand in 2015 through renewable resources, both those already owned and operated by the utility and those contracted for via long-term purchased power agreements (Barbose et al. 2008). The purchase power agreements in 2008 are assumed to be comprised of both short-term and long-term contracts predominantly with fossil-fuel powered generators. Once the short-term contracts expire, we assumed that the utility will increasingly sign power purchase contracts with renewable energy suppliers, in order to meet the RPS requirements. Based on these assumptions, we developed a resource expansion plan and associated capital expenditure budget forecast from 2008 to 2027 for both T&D related infrastructure and new generation projects (see Figure A-5).[62] The introduction of these new

overall composite cost of fuel and purchased power. However; such an ambitious characterization of the utility's supply-side assets was not undertaken for simplicity sake. Instead, we opted to produce a reasonable portfolio-level heat rate for each fuel type (i.e., nuclear, coal, natural gas, renewable, and purchased power) in order to derive an initial estimate of the fuel and purchased power costs the utility incurs (the same method was applied to produce non-"new generation" O&M budgets). With each new plant addition, we assumed that a reasonable proxy for the reduction in heat rate of the generation portfolio would be a smaller growth rate in fuel and purchased power costs (i.e., by 1 percentage point).

[62] Our resource expansion plan and its resulting impact on capital expenditure, fuel and purchased power, and O&M budgets assume no plant retirements occur during the 20-year analysis period.

power plants is expected to have an impact on the resource mix, and hence cause retail rates to change annually, via fuel and purchased power costs adjustments, over the entire 20-year analysis period. Figure A-6 illustrates how the proportion of the supply mix met through purchased power contracts remains relatively constant (~27%) throughout the analysis period, even though the source of energy that underlies the purchased power agreements changes over time. The share of resource needs met with coal increases in 2018 with the addition of an IGCC plant, while the share met by utility-owned renewable energy does not change because new renewables are included as part of purchased power.

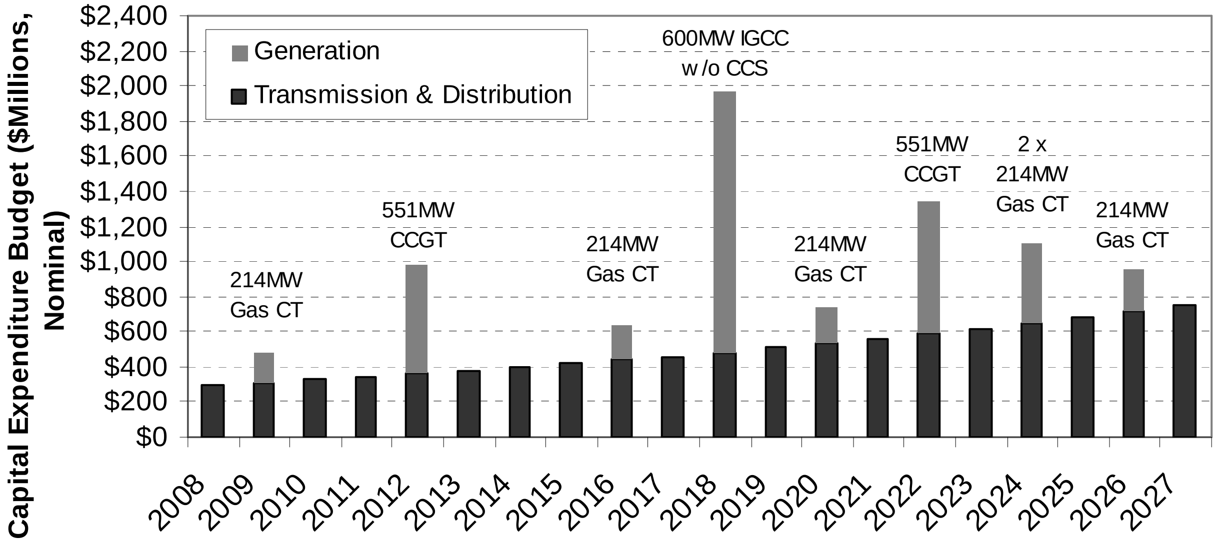



**Figure A-5. Annual capital expenditure budget for prototypical Southwest utility**

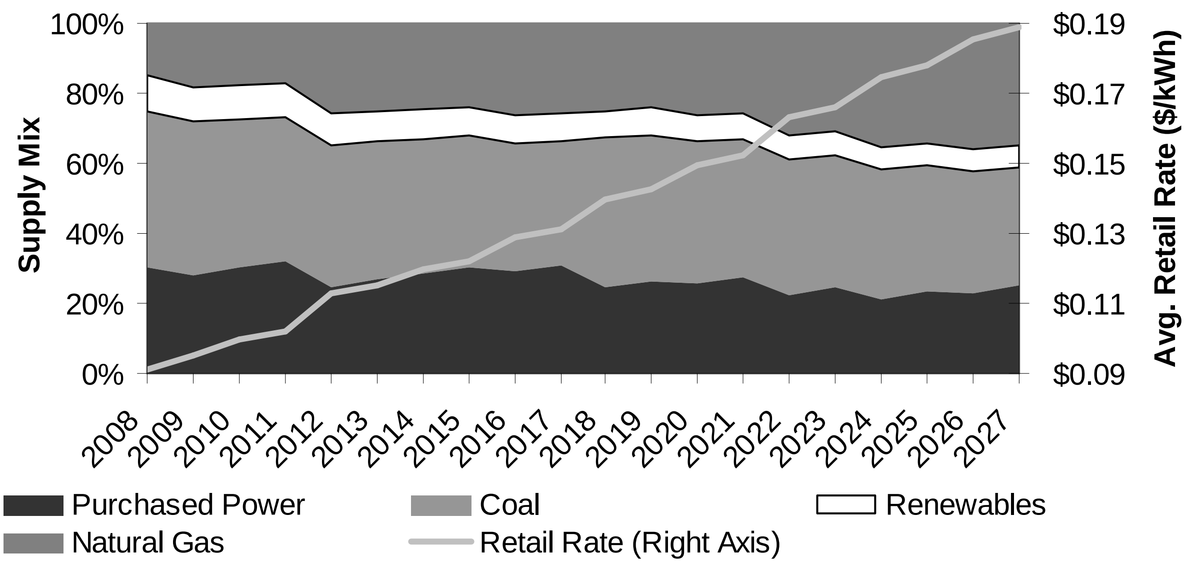



**Figure A-6. Annual resource mix and average retail rates for prototypical Southwest utility**

One of the major contributing factors to increases in O&M budgets is the addition of new generation plant. Thus, the timing of incremental generation capital expenditures, as depicted in Figure A-5, will greatly influence the relative size of the prototypical utility's annual O&M

budget. The O&M budget was broken out into existing plant and new generation categories, in order to represent the additional funds necessary to operate and maintain new supply-side facilities. The first-year O&M budget was assumed to be $395M, and grows at an annual rate of 7%.[63] O&M budget dollars associated with new generation were derived from the FEAST model cost assumptions and were also assumed to increase by 7% per year (WRTEP 2007).

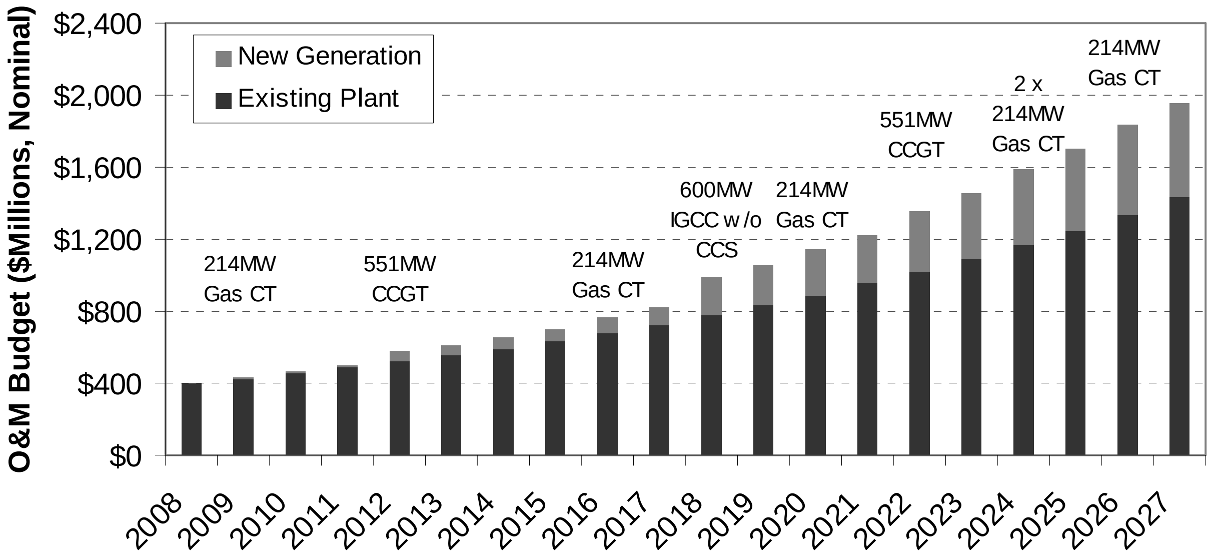



**Figure A-7. Annual O&M budget for prototypical Southwest utility**

Figure A-8 shows the annual revenue requirement and resulting retail rates for the prototypical southwest utility, given system characteristics and our input assumptions. The introduction of an IGCC coal plant in 2018 results in fuel and purchased power costs being reduced, while those costs associated with rate base (i.e., return, depreciation, and interest) all increase as this costly capital investment is placed into rate base. The jumps in retail rates over time can be linked to the investment in large generation projects. For example, in 2012, retail rates jump by 1.1 ¢/kWh with the 551 MW CCGT going on-line and in 2018 when rates increase by 9 mills/kWh with the installation of the 600 MW IGCC without CCS. Overall, average retail rates start out at 9.1 ¢/kWh in 2008 and increase to 18.9 ¢/kWh by 2027.

[63] This assumed annual growth rate for the O&M budget seems rather high at first glance. However; given the compound annual growth rates of O&M budgets observed at Arizona Public Service (7.4% over 5 years) and Nevada Power (7.8% over 3 years) it seems plausible and representative of utility experience in the region over the recent past.

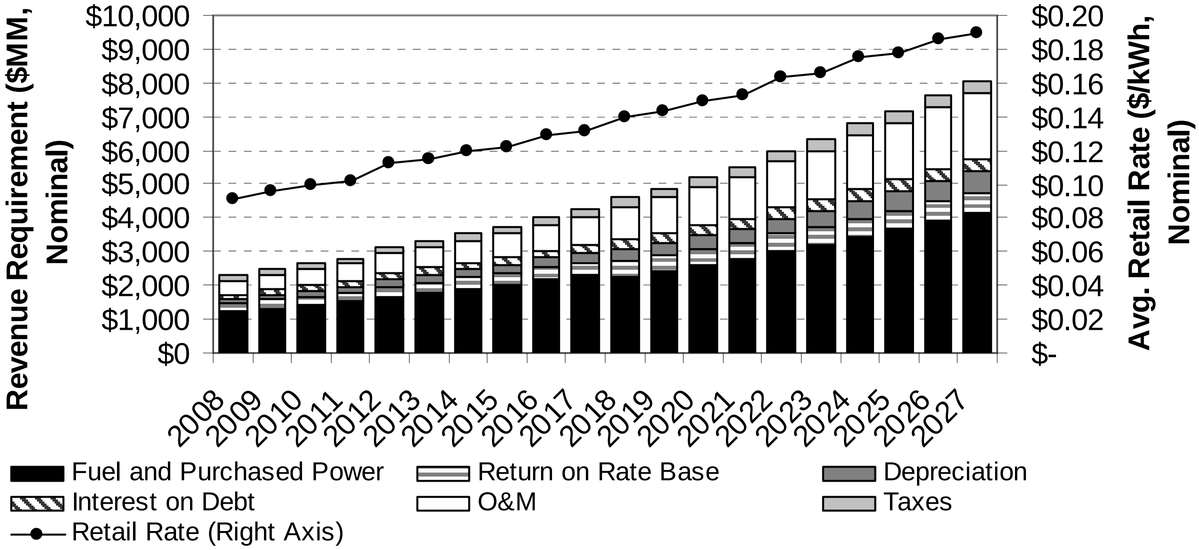



**Figure A-8. Annual revenue requirement and average retail rate for prototypical Southwest utility**

As a frame of reference, our prototypical utility's growth rates for various utility characteristics (e.g. retail sales, peak demand, fuel expenses) are generally between those observed for APS and NPC (see Figure A-9).

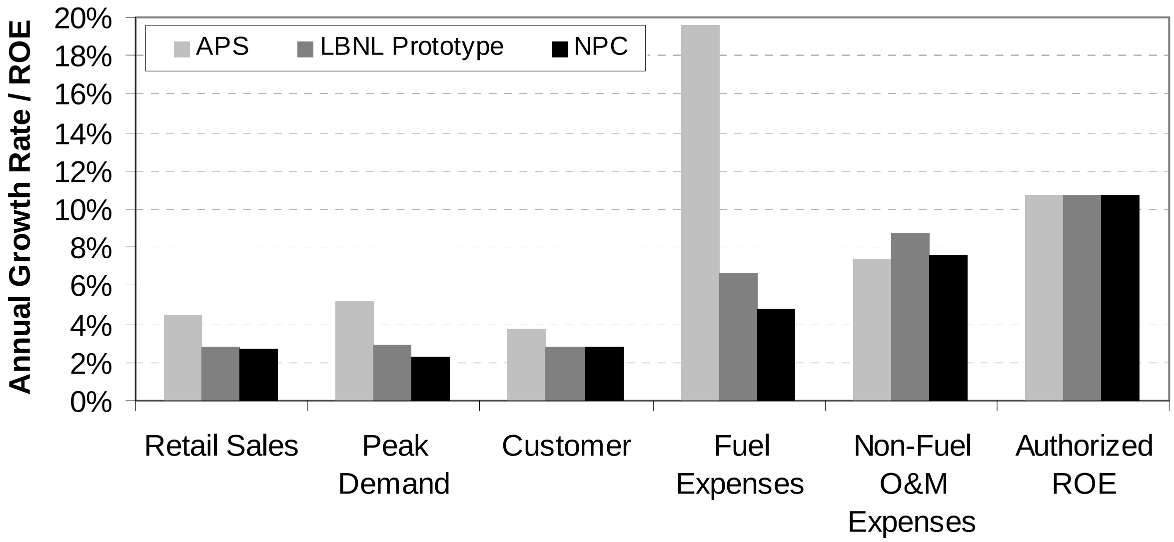



**Figure A-9. Comparison of ROE and growth rates of key physical and operating characteristics for Southwest utilities**

# Appendix B. Energy Efficiency Portfolio Characterization

In Appendix B, we summarize our approach and key inputs used to develop alternative energy efficiency portfolios.

## B.1 Constructing the prototypical utility energy efficiency portfolios

One of our goals was to construct three cases that were reasonably representative of the savings goals and costs likely to be observed and/or proposed in the southwest (and other regions). Currently, the majority of utilities in the southwest have achieved moderate savings levels in their energy efficiency programs, but several jurisdictions are in the process of ramping up their energy efficiency programs over the next several years (Geller and Schlegel, 2008).

The measures included in the portfolio of energy efficiency programs are designed to achieve the desired electricity savings goals and are focused on reductions in peak period retail sales, with minimal impact on the off-peak period. We defined the peak period to include a standard 16 hour time window used in wholesale power forward markets (e.g. 8 AM -10 PM weekdays). Given this lengthy peak period, 70% of the savings are assumed to occur during the weekday peak period, with 30% of the savings occurring in the off-peak hours. In order to achieve one MW of peak demand savings, we assumed our portfolio reduces annual retail electricity sales by 6,000 MWh. We retained this relationship between electricity and peak demand savings (i.e., 6,000 MWh of savings yields 1 MW reduction in peak demand) across the three energy efficiency portfolios. However the cost required to achieve more aggressive savings goals increases. Energy efficiency cost estimates used in our three portfolios are based, in part, on a review of public DSM filings from utilities in the southwest (Geller and Schlegel 2008) as well as experience and judgment of the authors.

Table B-1 includes the first five years of annual savings and cost data for our three EE portfolios and illustrates what would be required for the utility or program administrator (PA) to ramp up programs to meet the stated savings goal.[64]

The Moderate EE Portfolio was designed to achieve 0.5%/year incremental reduction in annual retail electric sales within two years of starting and maintain this level of incremental electricity savings each year for the next 8 years. We assume that this portfolio has total resource costs of 2.6 ¢/lifetime kWh, with administrative costs of the program accounting for 0.5¢/lifetime kWh from 2009 on.

The Significant EE portfolio was designed to achieve 1.0%/year incremental reduction in annual retail sales after a two year ramp up period. We assume that this EE portfolio has total resource costs of 3.0 ¢/lifetime kWh. Compared to the Moderate EE portfolio, there is an increase in both administrative costs (e.g., the utility must incur additional marketing and other administrative costs) and the cost of EE measures as customers to undertake the installation of more expensive measures in order to produce this higher level of savings.

[64] Program and measure costs reported in Table B-1 are stated in real dollars (2008$), not in nominal $. This allows for a comparison of costs in each year across the different portfolios. When implemented in the Benefits Calculator, these costs were assumed to increase by 1.9%/year annually in order to generate nominal figures.

The Aggressive EE portfolio represents a very ambitious goal to achieve 2.0%/year incremental reduction in annual retail electricity sales within five years. We assume that the Aggressive EE portfolio has total resource costs of 4.0 ¢/lifetime kWh. In order to achieve these goals, the utility will provide additional training, information, technical assistance and financial incentives to enhance the capability of the local energy efficiency service provider infrastructure (e.g., retailers, vendors, contractors) as well as its own staffing needs, and necessary marketing materials to meet this stretch goal. Measure costs also increase as customers install additional and more expensive EE measures. In the Moderate and Significant EE portfolios, we assume that utility incentives account for 50% of incremental measure costs, with customers paying the remaining 50%. In the Aggressive EE portfolio, we assume that utility incentives are increased in order to encourage the installation of more comprehensive EE projects and that the utility's share increases to 67% of total measure costs by 2012 when the portfolio is ramped up fully to meet these aggressive goals.

**Table B-1. Energy efficiency portfolios for prototypical utility**

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| **Moderate EE Portfolio** | | | | | |
| Incremental Energy Savings | 0.25% | 0.50% | 0.50% | 0.50% | 0.50% |
| Admin Cost ($/Lifetime kWh) | $0.006 | $0.005 | $0.005 | $0.005 | $0.005 |
| Measure Incentive Cost ($/Lifetime kWh) | $0.011 | $0.011 | $0.011 | $0.011 | $0.011 |
| Participant Measure Cost ($/Lifetime kWh) | $0.009 | $0.010 | $0.010 | $0.010 | $0.010 |
| PA Cost ($/Lifetime kWh) | $0.017 | $0.016 | $0.016 | $0.016 | $0.016 |
| TRC Cost ($/Lifetime kWh) | $0.026 | $0.026 | $0.026 | $0.026 | $0.026 |
| TRC to PA Cost Ratio | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 |
| **Significant EE Portfolio** | | | | | |
| Incremental Energy Savings | 0.25% | 0.50% | 1.00% | 1.00% | 1.00% |
| Admin Cost ($/Lifetime kWh) | $0.006 | $0.005 | $0.006 | $0.006 | $0.006 |
| Measure Incentive Cost ($/Lifetime kWh) | $0.011 | $0.011 | $0.012 | $0.012 | $0.012 |
| Participant Measure Cost ($/Lifetime kWh) | $0.009 | $0.010 | $0.012 | $0.012 | $0.012 |
| PA Cost ($/Lifetime kWh) | $0.017 | $0.016 | $0.018 | $0.018 | $0.018 |
| TRC Cost ($/Lifetime kWh) | $0.026 | $0.026 | $0.030 | $0.030 | $0.030 |
| TRC to PA Cost Ratio | 1.5 | 1.6 | 1.7 | 1.7 | 1.7 |
| **Aggressive EE Portfolio** | | | | | |
| Incremental Energy Savings | 0.25% | 0.50% | 1.00% | 1.50% | 2.00% |
| Admin Cost ($/Lifetime kWh) | $0.006 | $0.005 | $0.006 | $0.007 | $0.008 |
| Measure Incentive Cost ($/Lifetime kWh) | $0.011 | $0.011 | $0.012 | $0.015 | $0.019 |
| Participant Measure Cost ($/Lifetime kWh) | $0.009 | $0.010 | $0.012 | $0.013 | $0.013 |
| PA Cost ($/Lifetime kWh) | $0.017 | $0.016 | $0.018 | $0.022 | $0.027 |
| TRC Cost ($/Lifetime kWh) | $0.026 | $0.026 | $0.030 | $0.035 | $0.040 |
| TRC to PA Cost Ratio | 1.5 | 1.6 | 1.7 | 1.6 | 1.5 |

* All costs are in Real $2008.

# Appendix C. Financial Modeling of Duke Energy Carolina's Save-a-Watt Mechanism

In Appendix C, we describe how Duke Energy Carolina's proposed Save-A-Watt (NC) approach was modeled in the EE Benefits Calculator for our prototypical southwest utility. We describe the technical approach used to quantify the size of the "revenue requirement" to be provided under the Save-a-Watt mechanism, including financial and regulatory accounting treatment.[65] We relied primarily on Duke's publicly available regulatory fillings in North Carolina in characterizing and modeling their Save-A-Watt proposal.

## C.1 Revenues

### C.1.1 **Revenue Requirement Calculation**

Duke Energy Carolina's May 7, 2007 filing of its Energy Efficiency plan contains formulae for calculating the avoided cost (capacity and energy) revenue requirement for its Save-A-Watt approach (Duke, 2007). In general, revenues derived from a vintage year set of program measures are determined as follows:

1. Determine the avoided energy (kWh) and capacity (kW-year) resulting from each DSM measure over its lifetime;
2. Use the projected marginal avoided cost of energy ($/kWh) and capacity ($/kW-year) associated with each measure to calculate the forecasted financial savings on an annual basis over each measure's lifetime;
3. Calculate the present value of the total annual forecasted avoided energy and capacity costs for each measure;
4. Treat this present value as if it were a rate base investment, i.e., determine annual depreciation charges over the lifetime of each installed measure using a straight-line method and determine return on rate base (including a gross-up for taxes) after accumulated depreciation has been subtracted; and
5. Multiply the depreciation and return values determined in (4) above by 90% to arrive at the avoided energy and capacity revenue requirement that is owed to the utility as Rider EE.

#### *C.1.1.1* **Formulae for Save-a-Watt Revenue Requirement**

Duke set forth a very specific methodology in Attachment B-1 of its May 7, 2007 filing with the NCUC (Duke, 2007) for deriving the Avoided Cost revenue requirement (*AC)* that results from the implementation of a specific demand side resource measure. Two components of avoided cost are explicitly identified by Duke: the avoided cost of energy and the avoided cost of capacity. Each has its own set of calculations; although they are similar in many respects. The actual calculations are laid out in detail below.

[65] The utility's owed revenue requirement is calculated on a pre-tax basis. Thus, ratepayers are obliged to pay this amount to the utility grossed-up for the assumed 38% tax liability faced by the utility (e.g., local, state and federal government taxes). This calculation is not included explicitly in the formulae but is applied in the Benefits Calculator to ensure the utility receives the full-value of what it is owed.

Although Duke's filing applied these calculations at the measure level, we have not specified individual measures as part of our analysis; rather focusing on a portfolio of unspecified energy efficiency measures that achieves a certain level of energy and peak demand savings and have an average expected lifetime of 11 years. Thus, we used Duke's formulae to derive the Rider EE revenues but did so at a more aggregate portfolio level, rather than for each individual measure. We believe that our simplified approach would have a minimal effect on the final revenue requirement for a set of EE programs.

In the interest of maintaining consistency with Duke's filing, we have attempted to retain to the degree possible their originally filed (i.e. May 2007) variable names, but have also added new intermediate variables to better allow readers to follow our calculations. Furthermore, we make a distinction between the year indexing for calculating present value of avoided savings (index $i$), the year indexing for calculating the revenue requirement for a specific **vintage year** portfolio of measures (index $v$), and the year indexing for calculating the annual revenue requirement the utility is owed in a specific **program year** by ratepayers for implementing energy efficiency measures that have not yet reached the end of their useful lifetime (index $y$).

For simplicity, we have assumed that a vintage year portfolio of program measures is fully installed on January 1$^{st}$ of that year. This assumption was used because of the difficulty associated with deriving what fraction of the measures was installed at which time over the course of the year. The same holds true for the measure lifetime – clearly there is a distribution of measure lifetimes in a portfolio of EE measures, and even within the same measure. For simplicity, we assume that all measures installed in a certain vintage year reach the end of their useful lifetime on December 31$^{st}$ $j$ years later (index $j$ representing the average lifetime in whole years of the portfolio of measures installed that vintage year).[66] Put differently, the utility is assumed to install all measures in the portfolio on the first day of the vintage year (index $i = 1$), in order to fully capture the annual energy and demand savings in that and every subsequent year (index $i$=1 through $j$) throughout the lifetime of the installed measures.

To illustrate how these year indices, of which there are many, relate to each other, Figure C- 1 shows the values for $i$, $j$, $v$, and $y$ for a portfolio of measures that are offered every year for five years and has a measure-weighted lifetime of 3 years. As can be seen, in program year 1 ($y$=1 or the first column), the only energy efficiency measures that are affecting the utility are those installed in vintage year 1 ($v$=1). Program year 2 ($y$=2 or column two), however, has measures from programs offered in both vintage year 1 ($v$=1) and 2 ($v$=2). In program year 3 ($y$=3 or the third column), EE portfolios from the previous three years ($v$=1, 2, and 3) are all impacting the utility. The following year ($y$=4 or column four), those measures installed in vintage year 1 ($v$=1) have reached the end of their useful lifetime and hence do not affect the utility any longer, but those installed in vintage years $v$=2, 3, and 4 continue to impact the utility. This cascading set of effects continues as time marches onward.

[66] For simplicity of exposition, we assume that the lifetime of the portfolio of measures ($j$) doesn't vary by vintage year. If it did, the equations reported here would become more cumbersome as the size of $j$ becomes dependent upon the vintage year being analyzed. The Benefits Calculator is perfectly capable of handling different portfolio measure lifetimes across different vintage years, even if the simplified equations here do not fully represent this capability.

**Portfolio Lifetime (Index j) = 3 Years**

**Program Year (Index y)**

| Vintage Year (Index *v*) | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| 1 | i=1 | i=2 | i=3 | | | | |
| 2 | | i=1 | i=2 | i=3 | | | |
| 3 | | | i=1 | i=2 | i=3 | | |
| 4 | | | | i=1 | i=2 | i=3 | |
| 5 | | | | | i=1 | i=2 | i=3 |

**Figure C- 1. Example of Save-a-Watt mechanism year indexing**

To determine the annual Avoided Cost of Energy revenue requirement for vintage year $v$ program portfolio in program year $y$ ($ACE_{v,y}$), it is first necessary to find the annual avoided cost of energy value in each year of the lifetime of this portfolio. Duke actually does the calculation on an hourly basis for all 8,760 hours of each year the measure is active. Since we are unable to model at this level of detail, we have instead broken out values across a single year into periods of time (index $p$=1 for standard 18-hour peak period and $p$=2 for off-peak period). Thus, the Annual Avoided Energy Total (i.e., the economic value of the avoided energy) for vintage year $v$ measures in year $i$ in period $p$ ($AAET_{v,i,p}$) is the annual period-specific energy saved ($PE_{v,i,p}$) multiplied by the annual period-specific avoided cost of energy ($AEC_{v,i,p}$),

$$(1)\ \ AAET_{v,i,p} = PE_{v,i,p} * AEC_{v,i,p}\,.$$

The present value of this stream of annual period-specific avoided cost savings over the lifetime $j$ of a vintage year $v$ portfolio of measures ($PVAAET_v$), is calculated by the discounting formula,

$$(2)\ \ PVAAET_v = \sum_{i=1}^{j} \frac{\sum_{p=1}^{2} AAET_{v,i,p}}{(1+d)^i}\,.$$

For the discount rate, $d$, we use the utility's pre-tax Weighted Average Cost of Capital (*WACC*). Straight-line depreciation of this "rate-base component" is then applied over the measure life $j$, with each year's "depreciation" $DE_v$ given by

$$(3)\ \ DE_v = \frac{PVAAET_v}{j}\,.$$

In each year $i$, there is a remaining undepreciated balance called the Avoided Energy Investment ($AEI_{v,i}$),

$$(4)\ \ AEI_{v,i} = PVAAET - \left(i * DE_v\right) \ \ for\ i \in \left[1, j\right].$$

The utility is authorized to collect a return ($RE_{v,i}$) from ratepayers at its authorized after-tax equity-weighted Return on Equity (*ROE*) on this annual (undepreciated) avoided investment,

(5) $RE_{v,i} = ROE * AEI_{v,i}$, where

(6) $ROE = \dfrac{COE * EP}{(1 - ITR)}$, where

*COE* is the cost of equity (i.e., the authorized return for the utility), *EP* is the percentage of equity in the utility's capital structure, and *ITR* is the combined local, state and federal income tax rate of the utility. Thus, the annual Avoided Cost of Energy revenue requirement ($ACE_{v,y}$) for vintage year *v* portfolio of measures in program year *y* is,

(7) $ACE_{v,y=v+i-1} = DE_v + RE_{v,i} \;\; for\ i \in [1, j]$.

Determining the annual Avoided Cost of Capacity revenue requirement for vintage year *v* program portfolio in program year *y* ($ACC_{v,y}$) is accomplished in a similar manner as the Avoided Cost of Energy revenue requirement, with one exception. The Annual Avoided Capacity Total (i.e., the economic value of the avoided capacity) for vintage year *v* measures in year *i* ($AACT_{v,i}$) is comprised of two different components: generation and transmission & distribution.[67] The generation component of the Annual Avoided Capacity Total is the annual peak demand impacts ($PD_{v,i}$) times the annual avoided cost of generation capacity ($ACGC_{v,i}$), while the T&D component is 50% of the annual peak demand impact valued at the annual avoided cost of T&D capacity ($ACTDC_{v,i}$),[68]

(8) $AACT_{v,i} = \left(PD_{v,i} * ACGC_{v,i}\right) + \left(0.50 * PD_{v,i} * ACTDC_{v,i}\right)$,

The present value of this stream of annual period-specific avoided cost savings over the lifetime *j* of a vintage year *v* portfolio of measures ($PVAACT_v$), is calculated by the discounting formula,

(9) $PVAACT_v = \sum_{i=1}^{j} \dfrac{AACT_{v,i}}{(1+d)^i}$.

For the discount rate, *d*, the utility's pre-tax Weighted Average Cost of Capital (*WACC*), would be used. Straight-line depreciation of this "rate-base component" is then applied over the measure life *j*, with each year's "depreciation" $DC_v$ given by

[67] In Duke's May 2007 filing, there is no explicit mention of these two components of capacity. However, subsequent conversations with Duke staff indicated to the degree that T&D investments are deferred due to the implemented efficiency measures, such avoided costs will be captured by their modeling efforts and be reflected in the avoided cost of capacity calculations. For transparency, we have chosen to explicitly show the two components' contribution to the overall Avoided Cost of Capacity revenue requirement used in our study.

[68] As discussed in greater detail in Chapter 3, we have chosen to mitigate the ability for demand-side resources to affect the transmission and distribution system.

(10) $DC_v = \frac{PVAACT_v}{j}$.

In each year *i*, there is a remaining undepreciated balance called the Avoided Capacity Investment ($ACI_{v,i}$),

(11) $ACI_{v,i} = PVAACT - (i \times DC_v) \;\; for\; i \in [1, j]$.

The utility is authorized to collect a return ($RC_k$) from ratepayers at its authorized after-tax equity-weighted Return on Equity (*ROE*) on this annual (undepreciated) avoided investment,

(12) $RC_{v,i} = ROE * ACI_{v,i}$ , where

Thus, the annual Avoided Cost of Capacity Revenue Requirement ($ACC_{v,y}$) for vintage year *v* portfolio of measures in program year *y* is,

(13) $ACC_{v,y=v+i-1} = DC_v + RC_{v,i} \;\;\; for\; i \in [1, j]$.

Since installed measures continue to provide energy and demand impacts throughout their useful lifetime, the revenue requirement owed to the utility in any given program year (index *y*) is comprised of all vintage year programs (index *v*) that are in effect that program year. However, Duke requested to collect 90% of the calculated avoided energy and capacity revenue requirements from its ratepayers. The final annual Avoided Cost revenue requirement ($AC_y$) owed to the utility in program year *y* is,

(14) $AC_y = \sum_{v=Max(y-j,1)}^{y} \left( AEC_{v,y} + ACC_{v,y} \right)$.

The Benefits Calculator does not break out customers by class, but rather treats the entire utility as one customer class. Without any customer delineation, the Avoided Cost revenue requirement associated with Save-a-Watt is distributed across the entire utility customer base without regard to which class might benefit or install the measures that comprised the DSR portfolio.

### C.1.2 **Financial Accounting Revenues**

The Save-a-Watt incentive mechanism, like other shareholder incentives, is modeled as a rate rider. The shareholder incentive owed to the utility is calculated each year and separately rolled into rates, as if the forecast rate rider were perfectly realized every year. This means that, unlike other revenue requirement amounts, the amount collected related to the Save-a-Watt mechanism is not impacted by sales fluctuations. The collection of this rate rider is also fully realized and flows directly into the utility as a component of its revenue requirement. The shareholder incentive contributes directly to financial accounting profits, and so increases earnings and ROE, even though it is not technically part of the utility's rate base.

## C.2 Costs

Most utilities keep two separate sets of financial accounting books when tracking revenues and expenses: one set that follows Generally Accepted Accounting Principles (GAAP) and is used to report information to financial markets; and a second set that follows standards imposed by the regulatory body for cost of service, revenue requirement, and rates calculations. The treatment of costs as capitalized or rate base, depreciation of capital assets, tax deferral, and other financial calculations can differ substantially between these two methods. Therefore, to accurately capture the utility's financial standing, it is necessary to integrate the treatment of expenses from both sets of books.

### C.2.1 **Revenue Requirement Treatment of Program Costs**

The original Save-a-Watt proposal requested,

> "*…to defer the program costs and to amortize them over the life of the applicable program, with an acknowledgment that the revenues established in Rider EE, which are based on avoided costs, specifically include the recovery of incurred program costs. Such deferral accounting will not impact the ratemaking proposed by the Company, but will match the program expenses with the recognition of revenues from Rider EE in a reasonable manner for the Company's financial purposes.*" (Duke, 2007)

Because program expenses are explicitly already included and collected by Rider EE, Duke is not allowed to increase its annual revenue requirement or rates to separately collect energy efficiency program costs.

### C.2.2 **Financial Accounting Treatment of Program Costs**

While the revenues associated with the Save-a-Watt mechanism are established as if these avoided costs were capitalized, in fact there are no accounting assets associated with the Save-a-Watt mechanism. Therefore, the expenses that flow through the financial statements are related only to actually incurred program costs.

It is not clear whether the request quoted in C.2.1. "*…to defer the program costs and to amortize them over the life of the applicable program*" impacts the reporting of U.S. GAAP earnings. Nor is it clear how a utility regulatory body can impact U.S. GAAP treatment of these program costs. While expenses are generally recognized when the work or the product associated with the expense is recognized in revenue, expenses associated with administrative costs such as salaries and support activities are not deferred. For this reason, to calculate accounting earnings, we simply expensed the full value of the program administration and measure incentive costs in the year they were incurred. This results in a more conservative calculation of earnings in early years. Since the Rider EE revenue requirement produces revenues over the entire lifetime of the underlying measure life, while the program costs are expensed in the year they occur, the utility sees a large hit on its earnings in the first year of the program (i.e., vintage year), but would record only revenues in all subsequent years through the end of the measure's lifetime for programs implementing during a given vintage year.

## C.3 Simple Example of Calculations

To explicitly illustrate how our analysis constructed the Save-a-Watt revenue requirement, this section contains a (relatively) simple example. Our prototypical utility proposes three-year's worth of energy efficiency programs that looks similar to the Significant EE Portfolio developed in Chapter 3 but implements measures that have only a 5-year lifetime, for simplicity of calculations. Table C- 1 displays the annual program year energy and peak demand savings associated with this portfolio of vintage year programs.

**Table C- 1. Illustrative example of Save-a-Watt energy efficiency portfolio assumptions**

| | Program Year Peak Period Energy Savings (MWh) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | 43,750 | 43,750 | 43,750 | 43,750 | 43,750 | | |
| 2009 | | 89,950 | 89,950 | 89,950 | 89,950 | 89,950 | |
| 2010 | | | 184,937 | 184,937 | 184,937 | 184,937 | 184,937 |
| **Total** | **43,750** | **133,700** | **318,637** | **318,637** | **318,637** | **274,887** | **184,937** |

| | Program Year Off-Peak Period Energy Savings (MWh) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | 18,750 | 18,750 | 18,750 | 18,750 | 18,750 | | |
| 2009 | | 38,550 | 38,550 | 38,550 | 38,550 | 38,550 | |
| 2010 | | | 79,259 | 79,259 | 79,259 | 79,259 | 79,259 |
| **Total** | **18,750** | **57,300** | **136,559** | **136,559** | **136,559** | **117,809** | **79,259** |

| | Program Year Peak Demand Savings (MW) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | 10 | 10 | 10 | 10 | 10 | | |
| 2009 | | 21 | 21 | 21 | 21 | 21 | |
| 2010 | | | 44 | 44 | 44 | 44 | 44 |
| **Total** | **10** | **31** | **75** | **75** | **75** | **65** | **44** |

The costs assumed to be avoided by the implementation of these energy efficiency portfolios are reported in Table C- 2 on an annual basis for the period of 2008 (the first year of vintage year 2008 programs) through 2014 (the last year of vintage year 2010 programs).[69]

[69] These avoided costs were also taken directly from the analysis in Chapter 3 and thus have effects associated with new generation coming on-line in the forecast.

**Table C- 2. Save-a-Watt mechanism: Example avoided costs of energy and capacity**

| **Program Year** | Avoided Peak Energy Cost ($/MWh) | Avoided Off-Peak Energy Cost ($/MWh) | Avoided Generation Capacity Cost ($/kW-Year) | Avoided T&D Capacity Cost ($/kW-Year) | Ave. Non-Fuel Retail Rate ($/kWh) |
|---|---|---|---|---|---|
| 2008 | $70.14 | $41.08 | $80.00 | $30.00 | $0.043 |
| 2009 | $73.11 | $42.82 | $81.52 | $30.57 | $0.043 |
| 2010 | $76.82 | $44.99 | $83.07 | $31.15 | $0.047 |
| 2011 | $80.14 | $46.94 | $84.65 | $31.74 | $0.047 |
| 2012 | $83.58 | $48.96 | $86.26 | $32.35 | $0.049 |
| 2013 | $88.83 | $52.03 | $87.89 | $32.96 | $0.054 |
| 2014 | $92.38 | $54.11 | $89.56 | $33.59 | $0.056 |

Utilizing these annual reductions in energy and peak demand, along with the costs these reductions avoid, it is possible to apply the formulae from above to construct the Annual Avoided Energy Total (AAET) and Annual Avoided Capacity Total (AACT), the annual Avoided Energy Investment (AEI) and Avoided Capacity Investment (ACI) using a discount rate of 8.6750% (pre-tax WACC), and finally the Avoided Energy (AE) and Avoided Capacity (AC) revenue requirements that would be owed to the utility from ratepayers (see Table C- 3).

**Table C- 3. Save-a-Watt Mechanism: Example calculations**

| | Program Year Annual Avoided Energy Total ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $3.839 | $4.001 | $4.204 | $4.386 | $4.575 | | |
| 2009 | | $8.227 | $8.644 | $9.018 | $9.406 | $9.996 | |
| 2010 | | | $17.772 | $18.542 | $19.338 | $20.551 | $21.373 |
| **Total** | **$3.839** | **$12.229** | **$30.621** | **$31.947** | **$33.319** | **$30.547** | **$21.373** |

| | Program Year Avoided Energy Investment ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $16.359 | $13.087 | $9.815 | $6.544 | $3.272 | | |
| 2009 | | $35.253 | $28.203 | $21.152 | $14.101 | $7.051 | |
| 2010 | | | $75.954 | $60.763 | $45.573 | $30.382 | $15.191 |
| **Total** | **$16.359** | **$48.341** | **$113.972** | **$88.459** | **$62.946** | **$37.432** | **$15.191** |

| | Program Year Annual Avoided Capacity Total ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $0.990 | $1.008 | $1.028 | $1.047 | $1.067 | | |
| 2009 | | $2.073 | $2.113 | $2.153 | $2.194 | $2.235 | |
| 2010 | | | $4.344 | $4.426 | $4.510 | $4.596 | $4.683 |
| **Total** | **$0.990** | **$3.082** | **$7.484** | **$7.626** | **$7.771** | **$6.831** | **$4.683** |

| | Program Year Avoided Capacity Investment ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $4.020 | $3.216 | $2.412 | $1.608 | $0.804 | | |
| 2009 | | $8.421 | $6.737 | $5.053 | $3.369 | $1.684 | |
| 2010 | | | $17.643 | $14.114 | $10.586 | $7.057 | $3.529 |
| **Total** | **$4.006** | **$11.566** | **$26.541** | **$20.578** | **$14.615** | **$8.652** | **$3.490** |

| | Program Year Revenue Requirement ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Avoided Energy | $4.219 | $13.057 | $31.844 | $29.856 | $27.867 | $22.934 | $14.856 |
| Avoided Capacity | $1.037 | $3.146 | $7.503 | $7.034 | $6.565 | $5.373 | $3.451 |
| **Total** | **$5.256** | **$16.204** | **$39.347** | **$36.890** | **$34.433** | **$28.307** | **$18.306** |

# Appendix D. Financial modeling of Duke Energy Ohio's Save-a-Watt Mechanism

In Appendix D, we describe Duke Energy Ohio's proposed Save-A-Watt approach and how it was modeled in the EE Benefits Calculator for the prototypical southwest utility. Specifically, we describe the technical approach used to quantify the size of the "revenue requirement" to be provided under this updated version of the Save-a-Watt mechanism, including financial and regulatory accounting treatment.[70] We relied primarily on Duke Energy Ohio's publicly available regulatory fillings in characterizing and modeling their Save-A-Watt proposal in Ohio.

## D.1 Revenues

### D.1.1 Revenue Requirement Calculation

Duke Energy Ohio's July 31, 2008 filing of its Electric Security Plan included testimony and exhibits that summarized and described the avoided cost (capacity and energy) revenue requirement for its updated Save-a-Watt approach (Duke, 2008a). In general, revenues derived from a vintage year set of program measures are determined as follows:

1. Determine the avoided energy (kWh) and capacity (kW-year) resulting from each installed DSM measure over its lifetime;
2. Use the projected marginal avoided cost of energy ($/kWh) and capacity ($/kW-year) associated with each measure to calculate the forecasted financial savings on an annual basis over each measure's lifetime;
3. Calculate the present value of the total annual avoided energy and capacity costs for each measure;
4. Multiply the present value of the total annual avoided costs by some sharing percentage (this represents the first piece of the revenue requirement – call it the incentive component);
5. Calculate the revenue lost from the lifetime avoided energy (kWh) valued at the non-fuel retail rate in effect during the vintage year (this represents the second piece of the revenue requirement – call it the lost revenue component); and
6. Every fourth year a true-up mechanism is applied to ensure, among other things, that the incentive component of the revenue requirement did not result in earnings exceeding some percentage of incurred program costs.

#### *D.1.1.1* Formulae for Save-a-Watt Revenue Requirement

Duke set forth a very specific methodology in Application Volume II of II of its July 31, 2007 filing with the PUCO (Duke, 2008b) for deriving the Avoided Cost revenue requirement (*AC)* that results from the implementation of a specific demand side resource measure. Two components of avoided cost are explicitly identified by Duke: the avoided cost of energy and the avoided cost of capacity. Each has its own set of calculations; although they are similar in many respects. The actual calculations are laid out in detail below.

[70] The utility's owed revenue requirement is calculated on a pre-tax basis. Thus, ratepayers are obliged to pay this amount to the utility grossed-up for the assumed 38% tax liability faced by the utility (e.g., local, state and federal government taxes). This calculation is not included explicitly in the formulae but is applied in the Benefits Calculator to ensure the utility receives the full-value of what it is owed.

Although Duke's filing applied these calculations at the measure level, we have not specified individual measures as part of our analysis; rather focusing on a portfolio of unspecified energy efficiency measures that achieves a certain level of energy and peak demand savings. Thus, we used Duke's formulae to derive revenues from their Save-A-Watt proposal but did so at a more aggregate portfolio level, rather than for each individual measure. We believe that our simplified approach would have a minimal effect on the final revenue requirement for a set of EE programs.

In the interest of maintaining consistency with Duke's filing, we have attempted to retain to the degree possible their originally filed (i.e. July 2008) variable names, but have also added new intermediate variables to better allow readers to follow our calculations. Furthermore, we make a distinction between the year indexing for calculating present value of avoided savings (index $i$), the year indexing for calculating the revenue requirement for a specific **vintage year** portfolio of measures (index $v$), and the year indexing for calculating the annual revenue requirement the utility is owed in a specific **program year** by ratepayers for implementing energy efficiency measures that have not yet reached the end of their useful lifetime (index $y$).

For simplicity, we have assumed that a vintage year portfolio of program measures is fully installed on January 1st of that year. This assumption was used because of the difficulty associated with deriving what fraction of the measures was installed at which time over the course of the year. The same holds true for the measure lifetime – clearly there is a distribution of measure lifetimes in a portfolio of EE measures, and even within the same measure. For simplicity, we assume that all measures installed in a certain vintage year reach the end of their useful lifetime on December 31st $j$ years later (index $j$ representing the average lifetime in whole years of the portfolio of measures installed that vintage year). [71] Put differently, the utility is assumed to install all measures in the portfolio on the first day of the vintage year (index $i = 1$), in order to fully capture the annual energy and demand savings in that and every subsequent year (index $i$=1 through $j$) throughout the lifetime of the installed measures.

To illustrate how these year indices, of which there are many, relate to each other, Figure D- 1 shows the values for $i$, $j$, $v$, and $y$ for a portfolio of measures that are offered each and every year for five years and has a measure-weighted lifetime of 3 years. As can be seen from the figure, in program year 1 ($y$=1 or the first column), the only energy efficiency measures that are affecting the utility are those installed in vintage year 1 ($v$=1). Program year 2 ($y$=2 or column two), however, has measures from programs offered in both vintage year 1 ($v$=1) and 2 ($v$=2). In program year 3 ($y$=3 or the third column), EE portfolios from the previous three years ($v$=1, 2, and 3) are all impacting the utility. The following year ($y$=4 or column four), those measures installed in vintage year 1 ($v$=1) have reached the end of their useful lifetime and hence do not affect the utility any longer, but those installed in vintage years $v$=2, 3, and 4 continue to impact the utility. This cascading set of effects continues as time marches onward.

[71] For simplicity of exposition, we assume that the lifetime of the portfolio of measures ($j$) doesn't vary by vintage year. If it did, the equations reported here would become more cumbersome as the size of $j$ becomes dependent upon the vintage year being analyzed. The Benefits Calculator is perfectly capable of handling different portfolio measure lifetimes across different vintage years, even if the simplified equations here do not fully represent this capability.

**Portfolio Lifetime (Index j) = 3 Years**

| Vintage Year (Index *v*) \ Program Year (Index y) | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| 1 | i=1 | i=2 | i=3 | | | | |
| 2 | | i=1 | i=2 | i=3 | | | |
| 3 | | | i=1 | i=2 | i=3 | | |
| 4 | | | | i=1 | i=2 | i=3 | |
| 5 | | | | | i=1 | i=2 | i=3 |

**Figure D- 1. Example of Save-a-Watt mechanism year indexing**

To determine the annual Avoided Cost of Energy for Conservation Revenue Requirement for program year *y* ($ACCOE_y$), it is first necessary to find the annual avoided cost of energy value in each year of the lifetime of this portfolio. Duke actually does the calculation on an hourly basis for all 8,760 hours of each year the measure is active. Since we are unable to model at this level of detail, we have instead broken out values across a single year into periods of time (index $p$=1 for standard 18-hour peak period and $p$=2 for off-peak period). Thus, the Annual Avoided Energy Total (i.e., the economic value of the avoided energy) for vintage year *v* measures in year *i* in period *p* ($AAET_{v,i,p}$) is the annual period-specific projected energy saved ($PCOE_{v,i,p}$) times the annual period-specific avoided cost of energy ($ACE_{v,i,p}$),

(1) $AAET_{v,i,p} = PCOE_{v,i,p} * ACE_{v,i,p}$ .

The present value of this stream of annual period-specific avoided cost savings over the lifetime *j* of a vintage year *v* portfolio of measures ($PVAAET_v$), is calculated by the discounting formula,

(2) $PVAAET_v = \sum_{i=1}^{j} \frac{\sum_{p=1}^{2} AAET_{v,i,p}}{(1+d)^i}$ .

For the discount rate, *d*, we use the utility's after-tax Weighted Average Cost of Capital (*WACC*).[72]

The utility is authorized to collect a portion of this present value of avoided energy costs from ratepayers. The percentage is not explicitly referenced in Mr. Schultz's testimony (Duke, 2008a), nor in the Rider DR-SAW contained in Application Volume II of II (Duke 2008b). We set this percentage value at 60%, based on the agreed upon sharing percentage for such programs contained in the Indiana Office of Consumer Councilor settlement agreement with Duke Energy

[72] Duke Energy Ohio explicitly referred to the use of the after-tax weighted average cost of capital in the NPV calculation (Duke, 2008b). This differs from their treatment of the NPV calculation in the North Carolina filing, where the discount rate was the **pre-tax** weighted average cost of capital.

Indiana (IOCC 2008).[73] Thus, the Avoided Cost of Energy for Conservation Revenue Requirement for program year *y* is,

$$(3)\ \ ACCOE_{y=v} = 60\% * PVAAET_v$$

The annual Avoided Cost of Capacity revenue requirement for program year *y* is calculated slightly differently for demand response programs ($ACDRC_y$) and conservation programs (a.k.a. energy efficiency programs) ($ACCOC_v$). In the former case, the utility is only able to receive the avoided cost benefits for the expected peak demand reductions in the current program year from any customers enrolled in its current suite of DR programs. For conservation programs, as in the avoided cost of energy calculations, the utility is able to receive the present value of the lifetime avoided cost of capacity savings.

Although not stipulated in the Duke Ohio filing, private conversations with Duke staff indicate that the Annual Avoided Capacity Total (i.e., the economic value of the avoided capacity) for vintage year *v* measures in year *i* ($AACT_{v,i}$) is comprised of two different components: generation and transmission & distribution.[74] The generation component of the Annual Avoided Capacity Total is the annual projected peak demand impacts ($PD_{v,i}$) times the annual avoided cost of generation capacity ($ACGC_{v,i}$), while the T&D component is 50% of the annual peak demand impact valued at the annual avoided cost of T&D capacity ($ACTDC_{v,i}$),[75]

$$(4)\ \ AACT_{v,i} = \left(PD_{v,i} * ACGC_{v,i}\right) + \left(0.50 * PD_{v,i} * ACTDC_{v,i}\right),$$

For demand response programs, the existing set of resources could be thought of in two different ways. First, the utility has offered a set of vintage year *v* DR programs that have subscribed customers for a pre-specified period of time (i.e., $i$=1 to $j$). Alternatively, the utility could simply subscribe customers for a single year to its DR programs (i.e., $i$=1).

The utility is authorized to collect a portion of this present value of avoided capacity costs from ratepayers. The percentage is not explicitly referenced in Mr. Schultz's testimony (Duke, 2008a), nor in the Rider DR-SAW contained in Application Volume II of II (Duke 2008b). We set the percentage value at 75%, based on the agreed upon sharing percentage for such programs contained in the Indiana Office of Consumer Councilor settlement agreement with Duke Energy Indiana (IOCC 2008).

Thus, the current program year *y* Avoided Cost of Capacity Revenue Requirement ($ACDRC_y$) is:

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[73] The example in this appendix utilizes a 60% sharing percentage, but in the main report this sharing percentage was reduced to 50% to better represent the current Duke Ohio Save-a-Watt proposal.
[74] In Duke's May 2007 filing, there is no explicit mention of these two components of capacity. However, subsequent conversations with Duke staff indicated to the degree that T&D investments are deferred due to the implemented efficiency measures, such avoided costs will be captured by their modeling efforts and be reflected in the avoided cost of capacity calculations. For transparency, we have chosen to explicitly show the two components' contribution to the overall Avoided Cost of Capacity revenue requirement as we are applying them.
[75] As discussed in greater detail in Chapter 3, we have chosen to mitigate the ability for demand-side resources to affect the transmission and distribution system.

$$(5)\quad ACDRC_y = 75\% * \sum_{v=y-j}^{y} AACT_{v,y-v}$$

For conservation (i.e., energy efficiency) programs, the present value of the stream of annual avoided cost savings over the lifetime *j* of a vintage year *v* portfolio of measures ($PVAACT_v$), is calculated by the discounting formula,

$$(6)\quad PVAACT_v = \sum_{i=1}^{j} \frac{AACT_{v,i}}{(1+d)^i}.$$

The utility is authorized to collect a portion of this present value of avoided capacity costs from ratepayers. The percentage is not explicitly referenced in Mr. Schultz's testimony (Duke, 2008a), nor in the Rider DR-SAW contained in Application Volume II of II (Duke, 2008b). We decided to set this value at 60%, based on the agreed upon sharing percentage for such programs contained in the Indiana Office of Consumer Councilor settlement agreement with Duke Energy Indiana (IOCC, 2008). Thus, the Avoided Cost of Capacity for Conservation Revenue Requirement for program year *y* is

$$(7)\quad ACCCE_{y=v} = 60\% * PVAACT_v.$$

On an annual basis, Duke Energy Ohio also explicitly requested to collect the revenue it would have received but for the implementation of these energy efficiency and demand response programs. It is unclear from both Mr. Schultz's testimony (Duke, 2008a) and from the Rider DR-SAW calculations in the Application Volume II of II (Duke, 2008b) whether the utility is asking for the lifetime lost revenue or some shorter time period. According to the settlement reached in Indiana with the IOCC, Duke Energy Indiana agreed to collect three-year's worth of lost revenue for every vintage year set of programs they implemented (IOCC 2008). With this as the only point of reference, we assumed that the prototypical southwest utility is able to collect lost revenue for three year's worth of program sales reductions. Thus, the lost margin (revenue) the utility is able to collect for a given program year *y* ($LM_y$) is equal to the average non-fuel portion of retail rates in program year *y* and the sum of the peak and off-peak period (*p*=1, 2) retail sales reductions over the vintage year programs that have not yet reached this three year milestone ($PCOE_{v,p}$):

$$(8)\quad LM_y = LMR_y * \sum_{v=y-3}^{y} \sum_{p=1}^{2} PCOE_{v,p}$$

Every fourth year, the utility has agreed to apply a true-up mechanism to capture differences between forecasted and actual sales levels, forecasted and actual peak demand and retail sales reductions from the implemented vintage year programs, and to apply an earnings cap that explicitly excludes the contribution of the lost margin to earnings.[76]

[76] In general, the true-up mechanisms for differences between forecasted and actual values are rather straight forward, and won't be discussed here. Our analysis does not include a sensitivity case where forecasts and actual sales reductions differ, so the true-up for these categories would be zero anyway.

The earnings cap in program year $y$ ($ECT_y$), where $y$ is only multiples of four (e.g., 4, 8, 12, etc.), is defined such that the calculated net income from the incentive piece of the Save-a-Watt Ohio proposal (i.e., equations (3), (5) and (7)) over the previous three vintage years ($CNI_y$) is limited by the net income cap ($NIC_y$).

(9) $ECT_y = NIC_y - Max\left(NIC_y, CNI_y\right)$ where $y \in \mathrm{mod}(y,4) = 0$

The Net Income Cap is represented by a percentage of actual incurred program administration and measure incentive costs. The percentage, however, varies with the achievement of target savings goals established by the legislature and/or public utility commission (i.e., achieving <80% of goals sets the cap at 9% of actual program costs, achieving 80% - 104% of goals sets the cap at 15% of actual program costs, and achieving >= 105% of goals sets the cap at 18% of actual program costs). In our study, we always assume that the utility achieves 100% of the established goals. Therefore the Net Income Cap ($NIC_y$) is always set at 15% of the three year sum of vintage year actual incurred program administration and measure incentive costs ($APC_v$),

(10) $NIC_y = 15\% * \sum_{v=y-4}^{y-1} APC_v$ where $y \in \mathrm{mod}(y,4) = 0$

The Calculated Net Income ($CNI_y$) takes the incentive portion of the Save-a-Watt mechanism, applies any true-ups for difference between forecasted and actual sales and program impacts, and deducts from this amount the three year sum of vintage year actual incurred program administration and measure incentive costs ($APC_v$).[77] Since our analysis assumes all forecasted values are fully realized, there is no need to show the true-up calculations.

(12) $CNI_y = \sum_{v=y-4}^{y-1}\left(ACCOE_v + ACCOC_v + ACDRC_v - APC_v\right)$, where $y \in \mathrm{mod}(y,4) = 0$

The final annual Avoided Cost revenue requirement ($AC_y$) owed to the utility in program year $y$ is,

(14) $AC_{y=v} = ACCOE_v + ACCOC_v + ACDRC_v + ECT_{y,\text{ where } y \in \mathrm{mod}(y,4)=0}$.

The Benefits Calculator does not break out customers by class, but rather treats the entire utility as one customer class. Without any customer delineation, the Avoided Cost revenue requirement associated with Save-a-Watt is distributed across the entire utility customer base without regard to which class might benefit or install the measures that comprised the DSR portfolio.

[77] In addition there are corrections for revenue-related and income taxes. Although these adjustments are not shown here for simplicity, they are indeed integrated into the Benefits Calculator.

### D.1.2 **Financial Accounting Revenues**

The Save-a-Watt incentive mechanism, like other shareholder incentives, is modeled as a rate rider. The shareholder incentive owed to the utility is calculated each year and separately rolled into rates, as if the forecast rate rider were perfectly realized every year. This means that, unlike other revenue requirement amounts, the amount collected related to the Save-a-Watt mechanism is not impacted by sales fluctuations. The collection of this rate rider is also fully realized and flows directly into the utility as a component of its revenue requirement. The derived revenue requirement for the shareholder incentive contributes directly to financial accounting profits, and so increases earnings and ROE, even though it is not technically part of the utility's rate base.

## D.2 Costs

Most utilities keep two separate sets of financial accounting books when tracking revenues and expenses: one set that follows Generally Accepted Accounting Principles (GAAP) and is used to report information to financial markets; and a second set that follows standards imposed by the regulatory body for cost of service, revenue requirement, and rates calculations. The treatment of costs as capitalized or rate base, depreciation of capital assets, tax deferral, and other financial calculations can differ substantially between these two methods. Therefore, to accurately capture the utility's financial standing, it is necessary to integrate the treatment of expenses from both sets of books.

### D.2.1 **Revenue Requirement Treatment of Program Costs**

In Mr. Schultz's testimony, Duke Energy Ohio indicated the Save-a-Watt proposal, "…*does not provide for explicit recovery of the Company's program costs*" (Duke 2007b) Because program expenses are already included, and perfectly collected by, Rider DR-SAW, Duke is not allowed to increase its annual revenue requirement or rates to separately collect program costs.

### D.2.2 **Financial Accounting Treatment of Program Costs**

Unlike in the Duke Energy Carolina filing where the company requested "…*to defer the program costs and to amortize them over the life of the applicable program"* (Duke 2007), no such language was included in the Duke Energy Ohio's filing (Duke 2008a). Thus, we continue to fully expense all incurred program administration and measure incentives costs in the year in which they are incurred.

## D.3 Simple Example of Calculations

To illustrate how we constructed the Save-a-Watt revenue requirement, this section contains a (relatively) simple example. Our prototypical utility proposes three-year's worth of energy efficiency programs that looks similar to the Significant EE Portfolio developed in Chapter 3 but implements measures that have only a 5-year lifetime, for simplicity of calculations.[78] Table C-

[78] Given the simplicity and duplicity of the demand response avoided cost calculations, we have excluded them from this simple example. In addition, the analysis described in this report only deals with energy efficiency measures, eschewing any analysis of demand response programs.

1 displays the annual program year energy and peak demand savings associated with this portfolio of vintage year programs.

**Table D- 1. Save-a-Watt example: Energy efficiency portfolio assumptions**

| Vintage Year | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|
| **Program Year Peak Period Energy Savings (MWh)** | | | | | | | |
| 2008 | 43,750 | 43,750 | 43,750 | 43,750 | 43,750 | | |
| 2009 | | 89,950 | 89,950 | 89,950 | 89,950 | 89,950 | |
| 2010 | | | 184,937 | 184,937 | 184,937 | 184,937 | 184,937 |
| **Total** | **43,750** | **133,700** | **318,637** | **318,637** | **318,637** | **274,887** | **184,937** |
| **Program Year Off-Peak Period Energy Savings (MWh)** | | | | | | | |
| 2008 | 18,750 | 18,750 | 18,750 | 18,750 | 18,750 | | |
| 2009 | | 38,550 | 38,550 | 38,550 | 38,550 | 38,550 | |
| 2010 | | | 79,259 | 79,259 | 79,259 | 79,259 | 79,259 |
| **Total** | **18,750** | **57,300** | **136,559** | **136,559** | **136,559** | **117,809** | **79,259** |
| **Program Year Peak Demand Savings (MW)** | | | | | | | |
| 2008 | 10 | 10 | 10 | 10 | 10 | | |
| 2009 | | 21 | 21 | 21 | 21 | 21 | |
| 2010 | | | 44 | 44 | 44 | 44 | 44 |
| **Total** | **10** | **31** | **75** | **75** | **75** | **65** | **44** |

The costs assumed to be avoided by the implementation of these energy efficiency portfolios are reported in Table D- 2 on an annual basis for the period of 2008 (the first year of vintage year 2008 programs) through 2014 (the last year of vintage year 2010 programs).[79]

**Table D- 2. Save-a-Watt mechanism example: Avoided costs of energy and capacity**

| Program Year | Avoided Peak Energy Cost ($/MWh) | Avoided Off-Peak Energy Cost ($/MWh) | Avoided Generation Capacity Cost ($/kW-Year) | Avoided T&D Capacity Cost ($/kW-Year) | Ave. Non-Fuel Retail Rate ($/kWh) |
|---|---|---|---|---|---|
| 2008 | $70.14 | $41.08 | $80.00 | $30.00 | $0.043 |
| 2009 | $73.11 | $42.82 | $81.52 | $30.57 | $0.043 |
| 2010 | $76.82 | $44.99 | $83.07 | $31.15 | $0.047 |
| 2011 | $80.14 | $46.94 | $84.65 | $31.74 | $0.047 |
| 2012 | $83.58 | $48.96 | $86.26 | $32.35 | $0.049 |
| 2013 | $88.83 | $52.03 | $87.89 | $32.96 | $0.054 |
| 2014 | $92.38 | $54.11 | $89.56 | $33.59 | $0.056 |

[79] These avoided costs were also taken directly from the analysis in Chapter 3 and thus have affects associated with new generation coming on-line in the forecast.

Utilizing these annual reductions in energy and peak demand, along with the costs these reductions avoid, it is possible to apply the formulae from above to construct the Annual Avoided Energy Total (AAET) and Annual Avoided Capacity Total (AACT), the present value of the annual avoided energy and capacity totals (PVAAET and PVAACT) using a discount rate of 7.432% (after-tax WACC), the Lost Margin Recovery Mechanism (LM), the True-Up Mechanism that includes the Earnings Cap calculations, and finally the complete revenue requirement that would be owed to the utility from ratepayers (see Table D- 3).

**Table D- 3. Save-a-Watt Ohio mechanism: Example calculations**

| | Program Year Annual Avoided Energy Total ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $3.839 | $4.001 | $4.204 | $4.386 | $4.575 | | |
| 2009 | | $8.227 | $8.644 | $9.018 | $9.406 | $9.996 | |
| 2010 | | | $17.772 | $18.542 | $19.338 | $20.551 | $21.373 |
| **Total** | **$3.839** | **$12.229** | **$30.621** | **$31.947** | **$33.319** | **$30.547** | **$21.373** |

| | Program Year Present Value of AAET ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $16.925 | | | | | | |
| 2009 | | $36.475 | | | | | |
| 2010 | | | $78.585 | | | | |
| **Total** | **$16.925** | **$36.475** | **$78.585** | **$0.000** | **$0.000** | **$0.000** | **$0.000** |

| | Program Year Annual Avoided Capacity Total ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $0.990 | $1.008 | $1.028 | $1.047 | $1.067 | | |
| 2009 | | $2.073 | $2.113 | $2.153 | $2.194 | $2.235 | |
| 2010 | | | $4.344 | $4.426 | $4.510 | $4.596 | $4.683 |
| **Total** | **$0.990** | **$3.082** | **$7.484** | **$7.626** | **$7.771** | **$6.831** | **$4.683** |

| | Program Year Present Value of AACT ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $4.156 | | | | | | |
| 2009 | | $8.707 | | | | | |
| 2010 | | | $18.242 | | | | |
| **Total** | **$4.156** | **$8.707** | **$18.242** | **$0.000** | **$0.000** | **$0.000** | **$0.000** |

| | Program Year Lost Margin Recovery Mechanism ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| **Vintage Year** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| 2008 | $2.659 | $2.659 | $2.916 | | | | |
| 2009 | | $5.466 | $5.996 | $5.996 | | | |
| 2010 | | | $12.328 | $12.328 | $12.889 | | |
| **Total** | **$2.659** | **$8.125** | **$21.241** | **$18.324** | **$12.889** | **$0.000** | **$0.000** |

| | True-Up Mechanism Revenue Requirement ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Program Costs | $5.313 | $10.475 | $24.690 | | | | |
| Net Income Cap | $0.797 | $1.571 | $3.703 | | | | |
| Calculated Net Income | $7.336 | $16.634 | $33.406 | | | | |
| Earnings Cap Account | -$6.539 | -$15.063 | -$29.703 | | | | |
| **Earnings Cap True-Up** | **N/A** | **N/A** | **N/A** | **-$51.305** | **N/A** | **N/A** | **N/A** |

| | Program Year Revenue Requirement ($MM) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
| Avoided Energy | $10.155 | $21.885 | $47.151 | $0.000 | $0.000 | $0.000 | $0.000 |
| Avoided Capacity | $2.494 | $5.224 | $10.945 | $0.000 | $0.000 | $0.000 | $0.000 |
| *Incentive Mechanism* | *$12.648* | *$27.109* | *$58.096* | *$0.000* | *$0.000* | *$0.000* | *$0.000* |
| *Lost Margin Mechanism* | *$2.659* | *$8.125* | *$21.241* | *$18.324* | *$12.889* | *$0.000* | *$0.000* |
| *True-Up Adjustment* | *N/A* | *N/A* | *N/A* | *-$51.305* | *N/A* | *N/A* | *N/A* |
| **Total** | **$15.307** | **$35.234** | **$79.337** | **-$32.980** | **$12.889** | **$0.000** | **$0.000** |

## Appendix E. Sensitivity Analysis

We also conducted sensitivity analysis to explore the impact of key market and regulatory uncertainties and risks on our prototypical utility, shareholder earnings, and customer bills and rates. The base case results identified trends and effects associated with the combination of different shareholder incentives, a decoupling mechanism, and three different EE portfolios. In the sensitivity cases, we vary key financial and physical assumptions from the base case and examine changes to the earnings formula in each shareholder incentive to better understand impacts on shareholders and customers. Specifically, we looked at three different scenarios:

1. **Low Growth Utility**: Utility growth rates in energy and peak demand sales and some utility cost categories are lower than the base case, in order to assess results for utilities with slower rates of load growth (see Table E- 1).
2. **Utility Build Moratorium**: We assume that a state PUC requires its utilities to acquire new generation resources using competitive procurements with private power producers, rather than through building new generation assets that can be put into ratebase. The utility relies solely on purchased power to meet future incremental resource needs. This scenario may be reflective of the situation facing distribution utility (that has divested generation) (see Table E- 1).
3. **Higher Cost Utility**: We assume that the utility's previous supply-side investment decisions and lower operating efficiency have substantially increased the utility's current cost of service, producing higher retail rates (compared to the base case) that are more representative of regions outside the Southwestern U.S. (see Table E- 1).

**Table E- 1. Change in utility characteristic over analysis period relative to Base Case**

| | Low Growth Utility | Utility Build Moratorium | Higher Cost Utility |
|---|---|---|---|
| **Retail Electric Sales** | ↓ | ⇔ | ⇔ |
| **Peak Electric Demand** | ↓ | ⇔ | ⇔ |
| **Customers** | ↓ | ⇔ | ⇔ |
| **Fuel Costs** | ⇔ | ↑ | ⇔ |
| **O&M Costs** | ↓ | ↓ | ↑ |
| **CapEx Costs** | ↓ | ↓ | ↑ |
| **Rate Base** | ⇔ | ↓ | ↑ |

## E.1 Low Growth Utility Sensitivity Case

Many jurisdictions across the country are experiencing much lower load and peak demand growth than is currently observed in and forecast for the southwest. The influx of new residents is generally slower in these regions than for our prototypical utility and thus the expansion of local businesses to meet this lower consumer demand is also reduced. Such a slowing of the economy, relative to the fast-paced southwest, would be expected to reduce the rate of growth in O&M budgets, defer the need for constructing new generation facilities, and mitigate some T&D system upgrades and expansion.

If the utility's growth in customers, energy, and demand, as well as its non-fuel budgets, are altered to be slower than the base case, the dominant effect from implementing energy efficiency is to impact the timing of the resource expansion plan.[80] Similarly sized energy efficiency portfolios have a greater impact on mitigating load and peak demand growth for the Low Growth utility compared to the prototypical utility under base case assumptions (Figure E- 1). After five years of energy efficiency programs, the Low Growth utility has offset nearly all growth in electricity sales with the Aggressive EE portfolio and 65% of its peak demand expansion. By 2017, the Low Growth utility has actually bent its sales forecast line down by implementing this EE portfolio, achieving over a 120% reduction in growth, and mitigating nearly 85% of its incremental peak demand. In contrast, the prototypical utility under base case conditions is able to offset about 73% of load growth and 49% of the growth in peak demand.

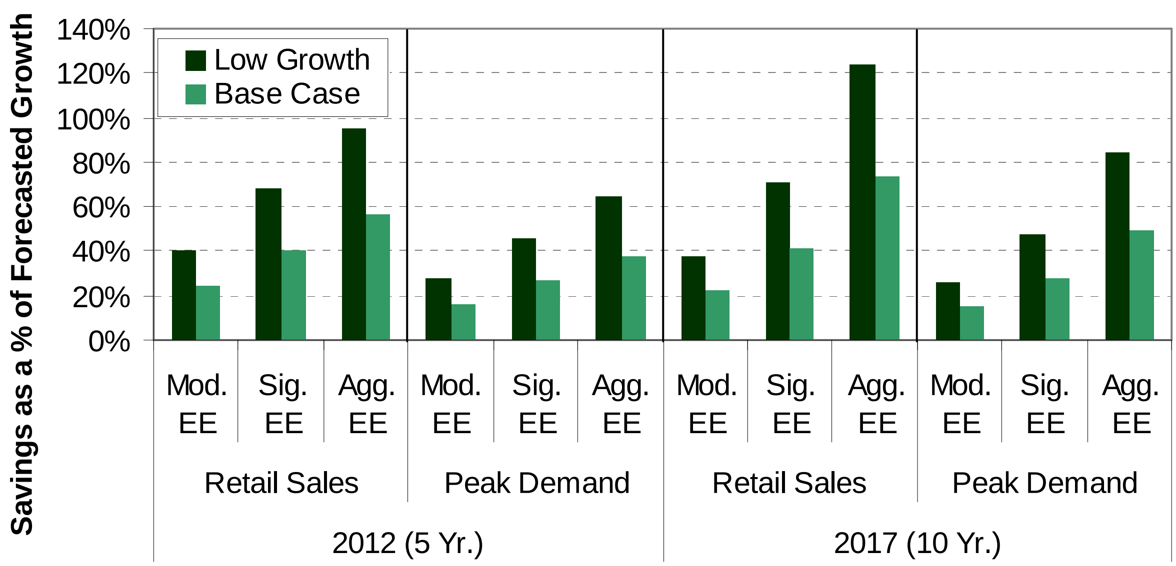


**Figure E- 1. Growth in retail sales and peak demand offset by energy efficiency**

The significant effect on sales and peak demand growth of the Aggressive EE portfolio at the Low Growth utility defers the need for new power plants and growth-related upgrades to the T&D infrastructure further into the future than is observed in the base case.[81] In the base case,

[80] In all figures and tables in this appendix, the "Base Case" refers to the results summarized in section 3.4.

[81] Due to the differences in demand and energy growth rates assumed in the Low Growth sensitivity case in relation to the Base Case, there are substantial differences in the size, technology and timing of planned supply-side

the prototypical utility defers the need for additional generation facilities by one year due to the introduction of any of the three energy efficiency portfolios. However, in the Low Growth sensitivity case, the utility reduces load and peak demand growth so much in response to the Aggressive EE goals that it is able to defer the construction of its supply side assets by two years starting with the 551 MW combined-cycle gas turbine plant, which is originally scheduled to go online in 2015 but now is not needed until 2017 (see Figure E- 2).

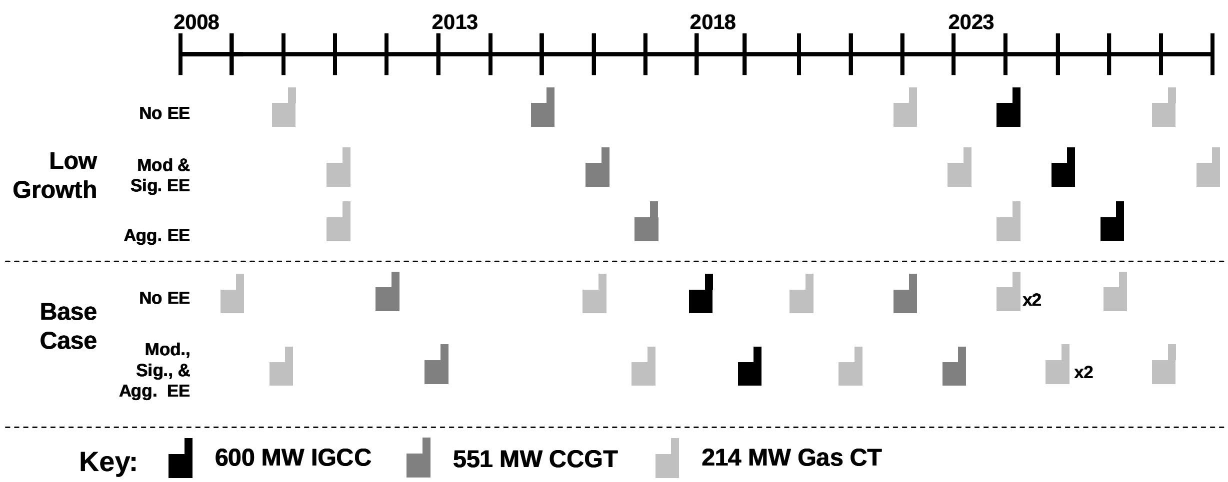


**Figure E- 2. Timing of major generation plan additions for Low Growth utility**

For example, if the Aggressive EE portfolio is implemented, investment dollars are pushed out further into the future at the Low Growth utility which lowers the annual capital expenditure budgets for new generation facilities and results in a lower basis for calculating utility returns. A substantially smaller rate base produces lower earnings for the utility, especially in relation to one where plants are only deferred one year, as occurs in the base case (Figure E- 3). The $145MM reduction in earnings for the low growth case under an Aggressive EE savings target is caused by the sizable reduction ($270MM) from its generation capital expenditure (CapEx) budget.

additions, as indicated above. This has consequences for the size of the utility's generation capital expenditure budget, but not for the timing of any deferral due to the implementation of energy efficiency. The deferral of the plants is strictly driven by an assessment of when the plant is originally needed (i.e., No EE) and when that same level of peak demand is reached once energy efficiency savings are realized. The model assesses this timing decision at an annual level, so deferrals are pushed out further into the future than they might be in reality.

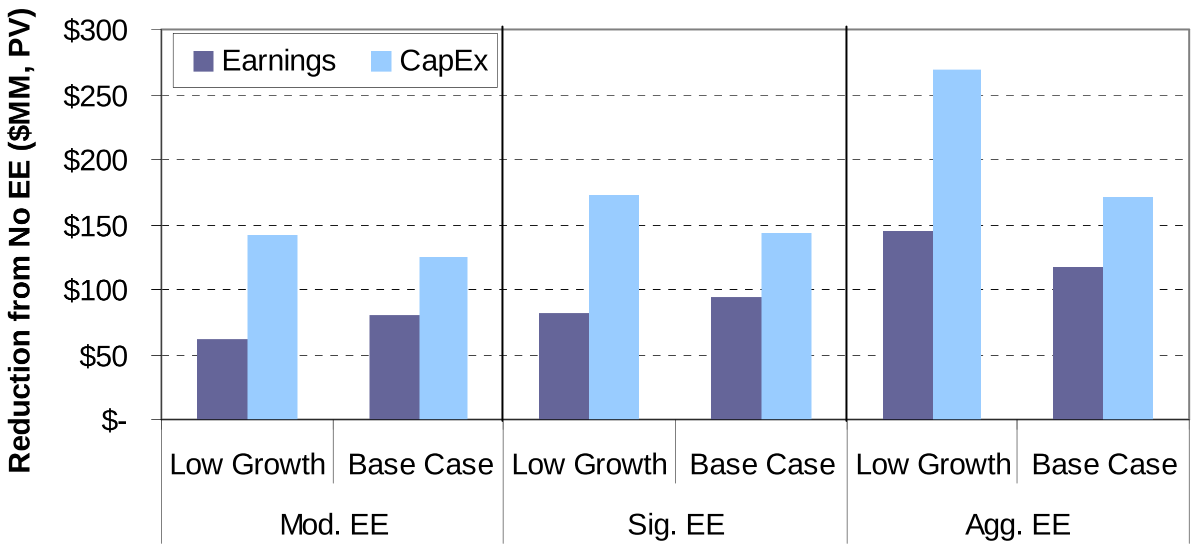


**Figure E- 3. Reduction in earnings and CapEx for Low Growth utility**

With less capital invested, the utility is able to issue substantially less equity (~$200MM) which, from an ROE perspective, greatly offsets the reduction in earnings. As illustrated in Figure E- 4, ROE is barely affected by the Aggressive EE portfolio in the Low Growth utility, in spite of the sizable drop in earnings – ROE falls by only two basis points relative to the rate of return that is achieved by the prototypical utility under base case assumptions implementing the same EE portfolio. Given the Low Growth utility's reduction of $270MM in earnings and 14 basis points in ROE when implementing the Aggressive EE portfolio, it is unlikely utility managers will focus on pursuing the Aggressive EE portfolio unless they can be financially compensated to either be better off, or at least achieve comparable levels of financial success.

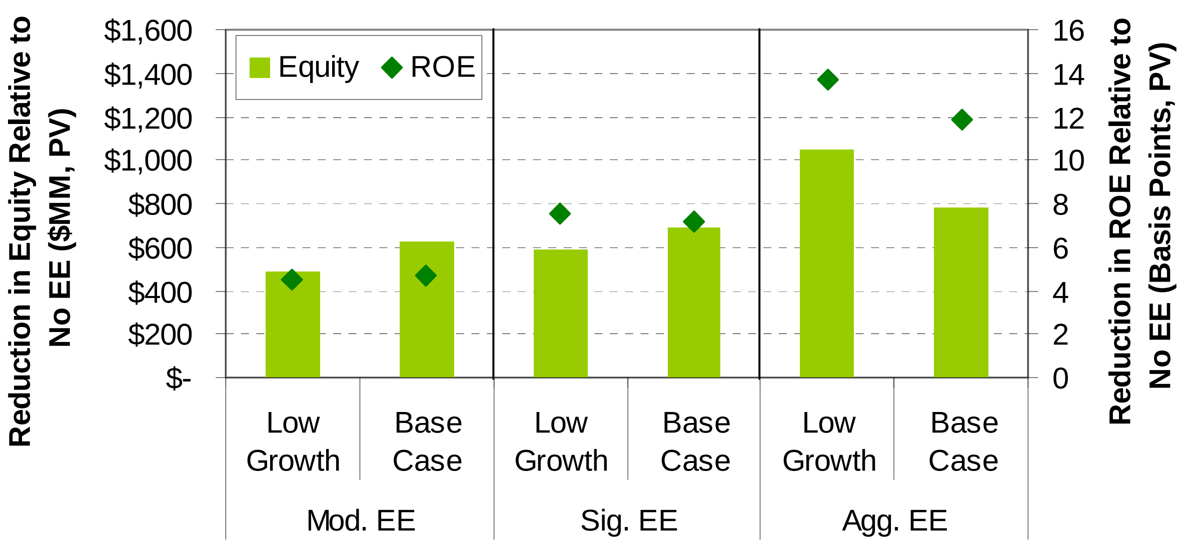


**Figure E- 4. Reduction in equity and ROE for Low Growth utility**

If the utility implements a decoupling mechanism, the financial benefits that are received by the Low Growth utility are not dramatically different from the base case. The rate of utility growth does not greatly affect achieved ROE once decoupling is applied, leaving the utility 1 basis point or less below what they would have achieved if energy efficiency was eschewed completely (Figure E- 5).

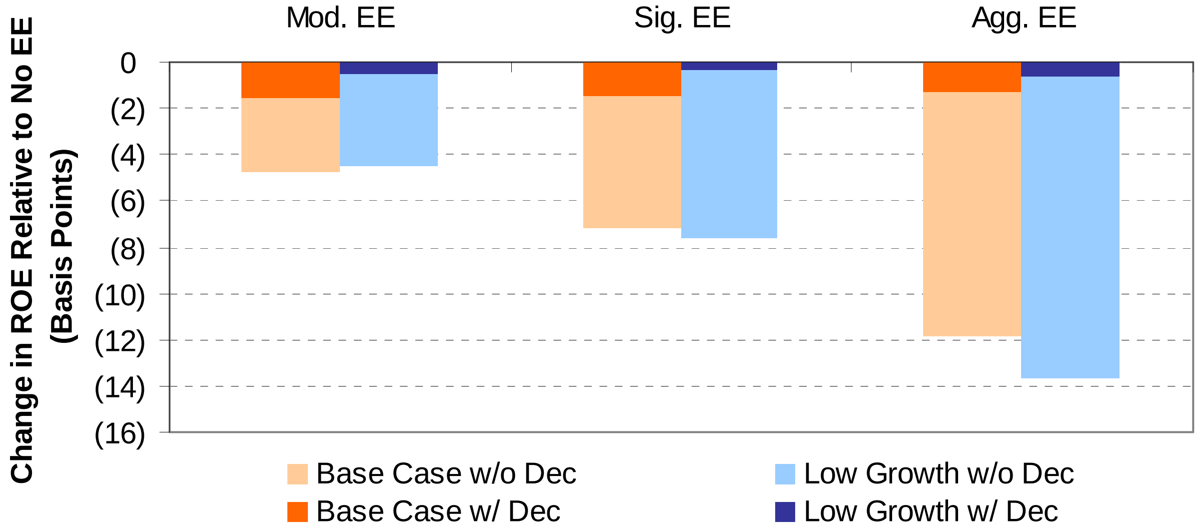


**Figure E- 5. Effect of decoupling on change in ROE relative to No EE case**

If a utility shareholder incentive mechanism is linked with the implementation of a decoupling mechanism, the Low Growth utility's change in earnings (Figure E- 6) and ROE (Figure E- 7) from EE is very similar to that achieved by the prototypical Southwest utility in the Base Case. As the level of EE savings increases at the Low Growth utility, earnings generally increase across all shareholder incentive mechanisms, except the Shared Net Benefits mechanism. In that case, the reduction in earnings, as observed for the Aggressive EE portfolio in Figure E- 4, is bigger than the contribution to earnings from both the decoupling and Shared Net Benefits shareholder incentive mechanisms. On the other hand, ROE is always improved with the introduction of a decoupling mechanism (see Figure E- 5), so applying a shareholder incentive in addition simply elevates the achieved return even more, but does so comparably across the two utilities.

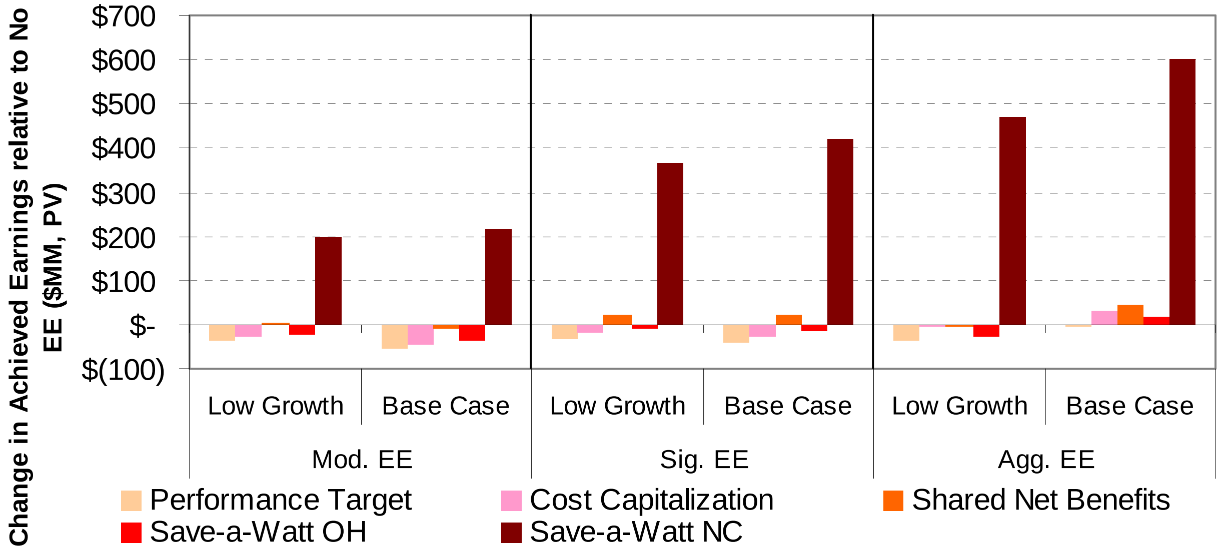


**Figure E- 6. Effect of decoupling or shareholder incentives on achieved earnings for Low Growth utility**

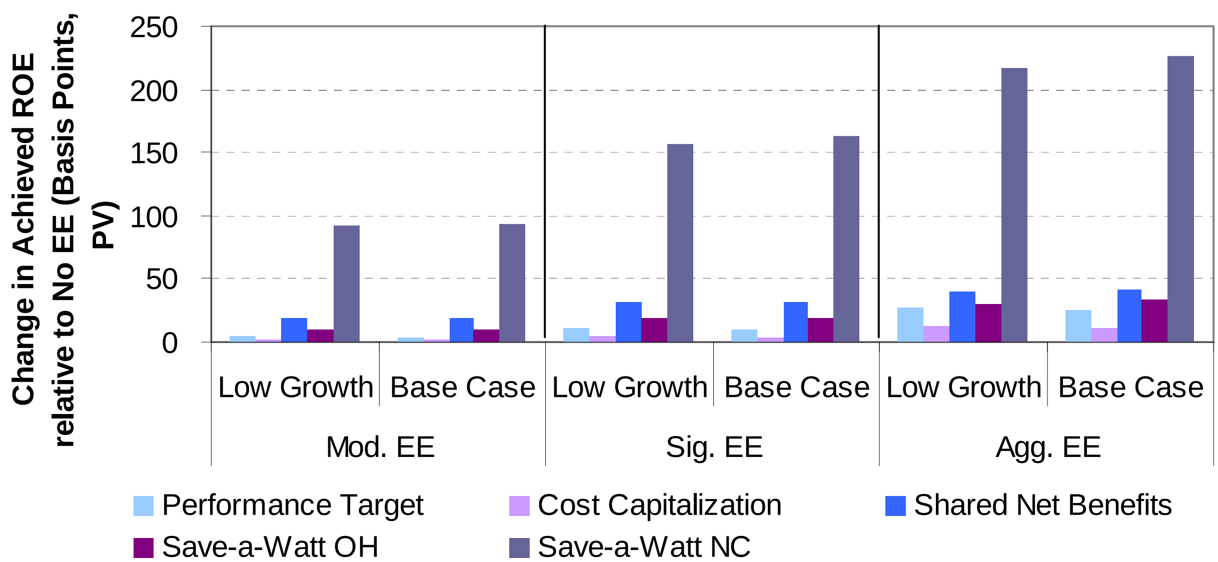


**Figure E- 7. Effect of decoupling or shareholder incentives on achieved ROE for Low Growth utility**

From the customer perspective, there are also relatively minor differences in bill savings (Figure E- 8) and retail rates (Figure E- 9) between the two cases and across the different shareholder incentive mechanisms. In general, as the level of EE savings increases, the Low Growth utility experiences slightly lower bill savings relative to the base case if the same shareholder incentive is applied. On the other hand, the impact on retail rates are generally higher in the Low Growth utility when either the Moderate or Significant EE portfolios are implemented, but drops below the base case for most shareholder incentive mechanisms when the Aggressive EE savings are achieved.

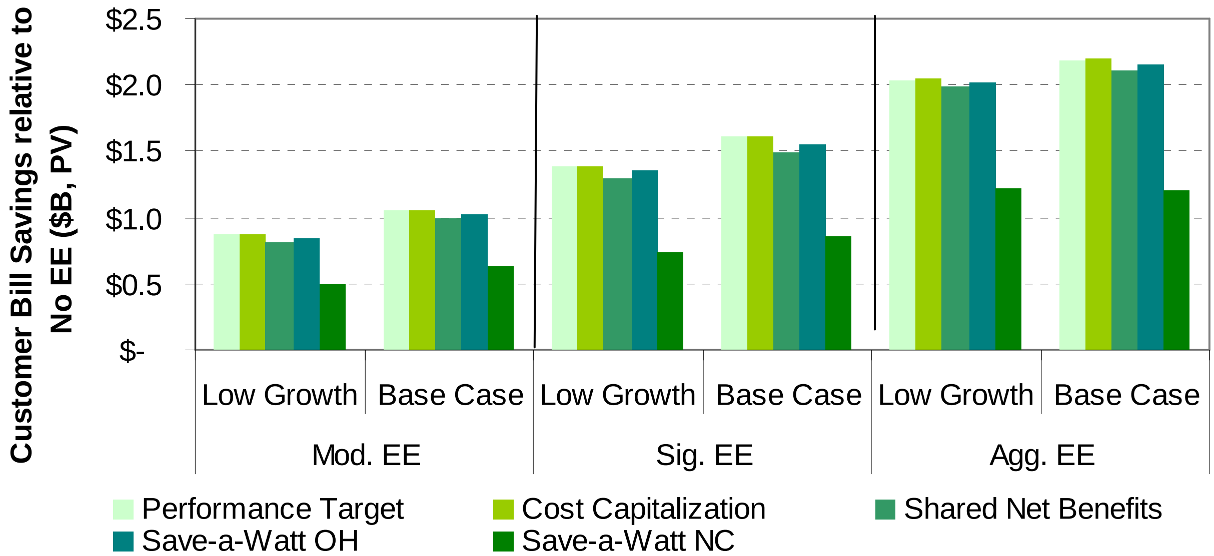


**Figure E- 8. Effect of decoupling or shareholder incentives on customer bill savings for Low Growth utility**

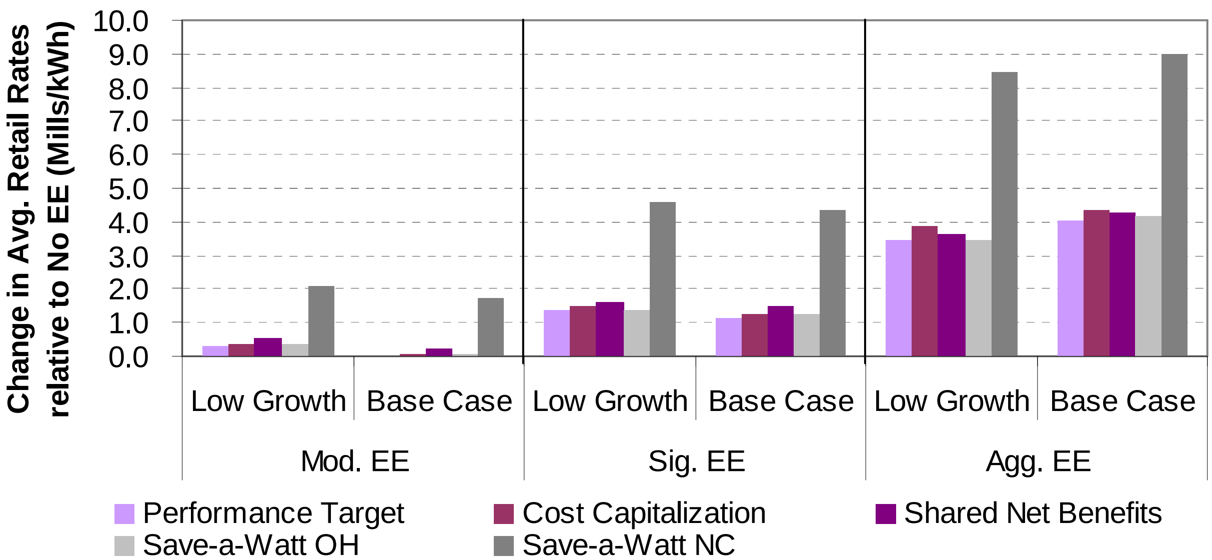


**Figure E- 9. Effect of decoupling or shareholder incentives on average retail rates for Low Growth utility**

## E.2 Utility Build Moratorium Sensitivity Case Results

In some jurisdictions, state PUCs require utilities to meet some or all new generation resource needs through competitive procurements involving contracts with private power producers, rather than the utility building new generation under rate-of-return regulation.[82] This type of procurement policy reduces the utility's future capital expenditure budgets for new rate-based generation assets, which are a major source of potential earnings from the utility's financial outlook. In this world where the utility must use purchased power contracts from the private market, though, the utility also issues far less equity.

The difference in earnings for the prototypical utility between the base case and this Utility Build Moratorium case before EE is even implemented is stark – $545MM lower under the latter situation over 20 years on a present value basis. The achieved ROE over this same time period is also substantially lower if the utility is not allowed to build its own generation assets: 10.32% for Build Moratorium vs. 10.43% for the base case (Figure E- 10).[83] Once energy efficiency programs are implemented at both utilities, the downward impact in ROE is comparable for each level of savings: ~4 basis points for the Moderate EE portfolio, ~7 basis points for the Significant EE portfolio, and ~12 basis points for the Aggressive EE portfolio.

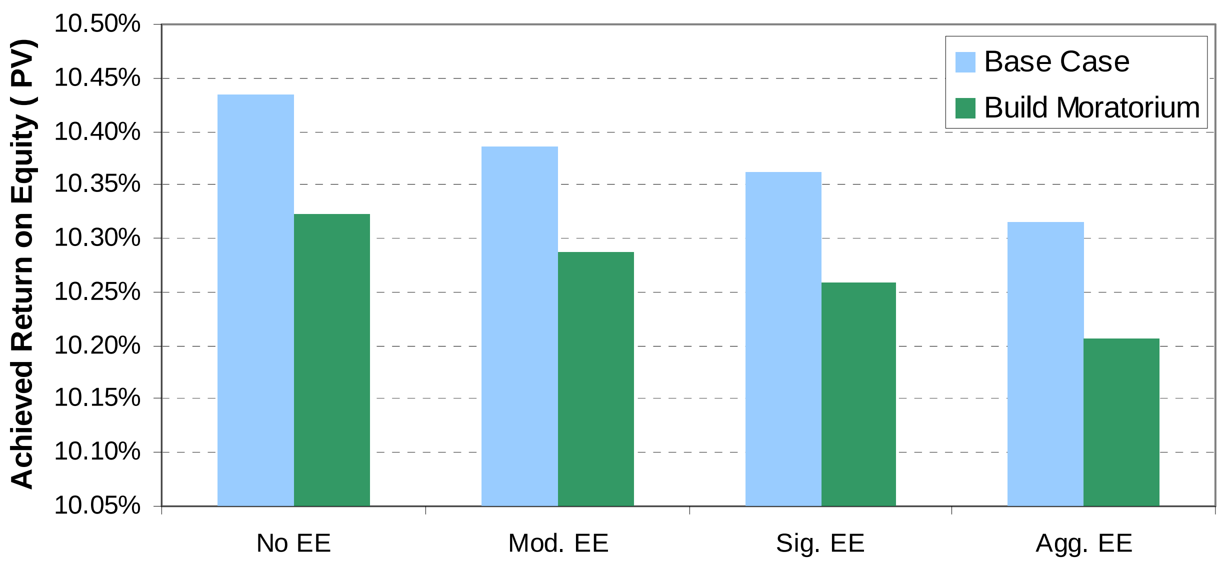


**Figure E- 10. Effect of energy efficiency on achieved ROE for Utility Build Moratorium case**

The introduction of new generation assets in the base case produces a rather volatile annual utility cost structure; some years costs grow by ~6% while in others they can grow by twice that amount when big capital expenditures are made, coming directly into rates via CWIP. This situation is not apparent in the Build Moratorium case, because the utility does not undertake

[82] In its general rate case settlement in 2005, Arizona Public Service agreed to a self-build moratorium for nearly 10 years, which compels the utility to rely more on merchant generators to meet its rapid native load growth (APS 2005).

[83] This result seems counterintuitive, but there are two things that are driving this result. First, in the base case, the prototypical utility receives Construction Work in Progress (CWIP), thereby allowing it to immediately begin to earn a return on this investment. Second, once these investments are rolled into rate base, the annual depreciation amount will be larger, resulting in a larger reduction in authorized annual return between rate cases. In the Utility Build Moratorium case, the revenue requirement will drop less between rate cases, requiring the retail rate to recover a larger authorized return, ceteris paribus. If other costs are rising rapidly, the earnings erosion between rate cases experienced in the base case is exacerbated in the Utility Build Moratorium case resulting in a lower achieved ROE.

such investments, but instead signs long-term contracts where a fraction of the capital costs of the plants are embedded in the purchased power agreement's variable cost and are amortized over the lifetime of the contract. Thus, retail rates do not increase nearly as much nor do they jump as dramatically in the Build Moratorium case, as they do in the base case (Figure E- 11). With lower retail rates but comparable savings from energy efficiency programs, ratepayers of the prototypical utility save more money (~$300MM) in the base case compared to the Build Moratorium utility (Figure E- 12).

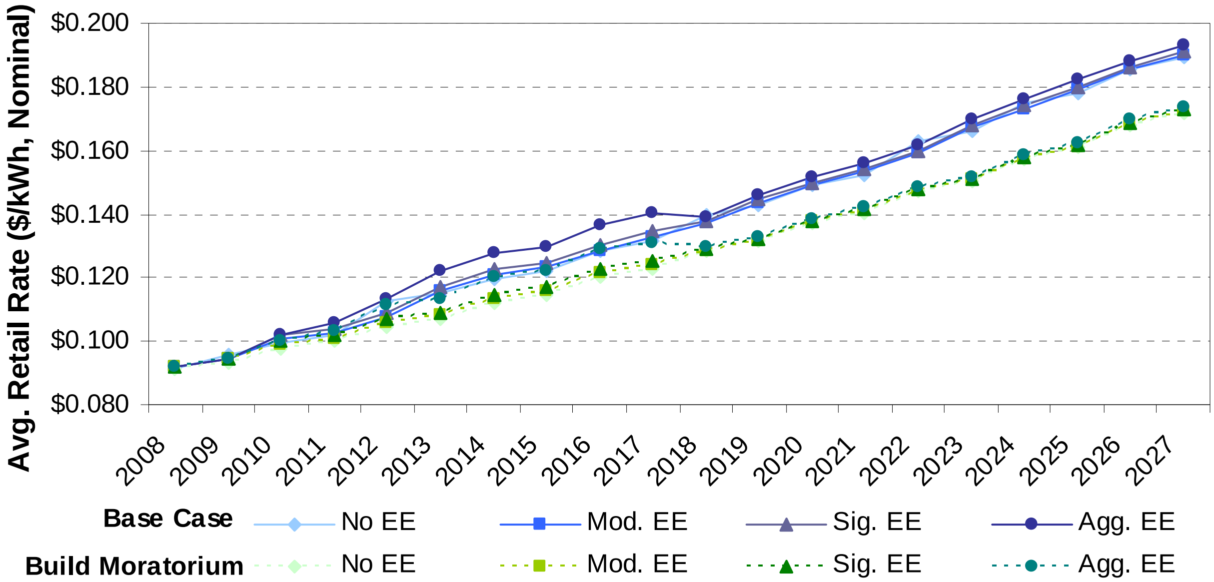


**Figure E- 11. Base Case and Utility Build Moratorium annual average retail rates**

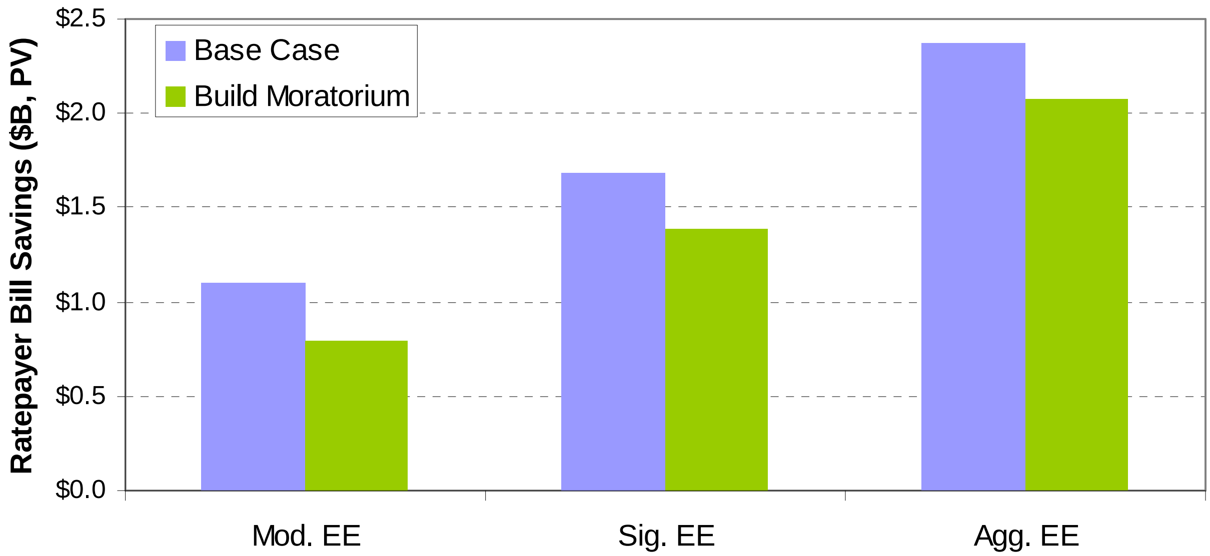


**Figure E- 12. Effect of energy efficiency on ratepayer bill savings for Utility Build Moratorium case**

The value of offering a decoupling mechanism in isolation or in conjunction with either a Performance Target, Shared Net Benefits or Cost Capitalization incentive mechanism, or a mechanism that combines a lost revenue recovery mechanism with an incentive implicitly (i.e., Save-a-Watt OH and Save-a-Watt NC), appears to be far greater when implemented in the Build Moratorium case than in the base case. As Figure E- 13 illustrates, there is nearly universal improvement in utility earnings when a financial incentive is provided to the Build Moratorium utility for implementing any sized portfolio of energy efficiency, while it is only when either more lucrative mechanisms are provided (e.g., Save-a-Watt NC) or the magnitude of the achieved sales and peak demand reductions are sizable (e.g., Significant EE, Aggressive EE) that such increases in utility earnings are achieved, relative to the case where energy efficiency is eschewed. Similarly, ROE increases more when financial incentives are given to the Build Moratorium utility compared to the prototypical utility in the base case (Figure E- 14).

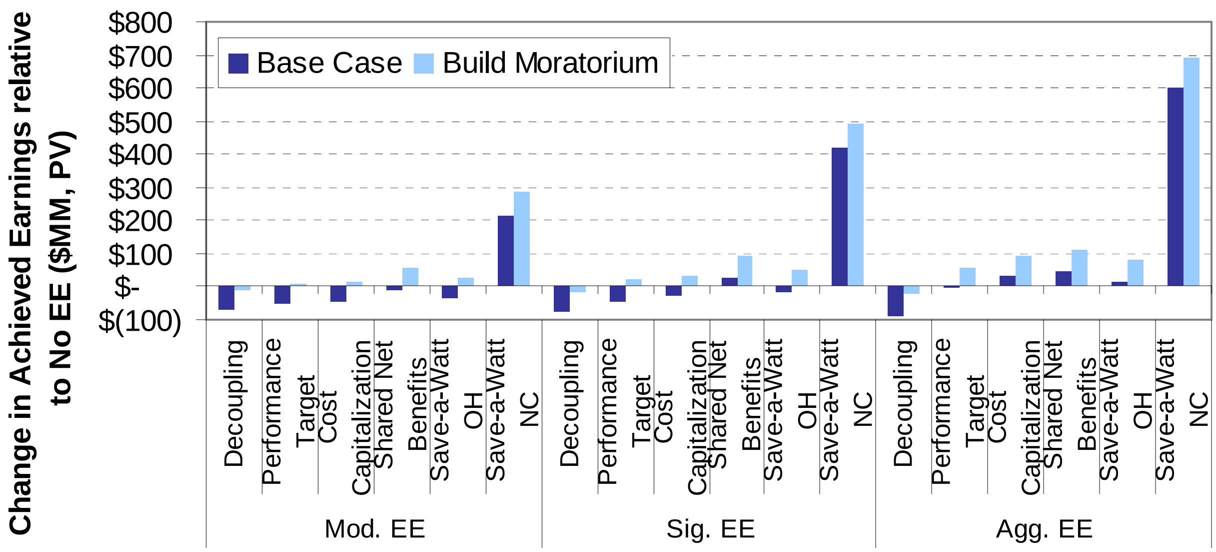


**Figure E- 13. Effect of decoupling and shareholder incentives on achieved earnings for Utility Build Moratorium Case**

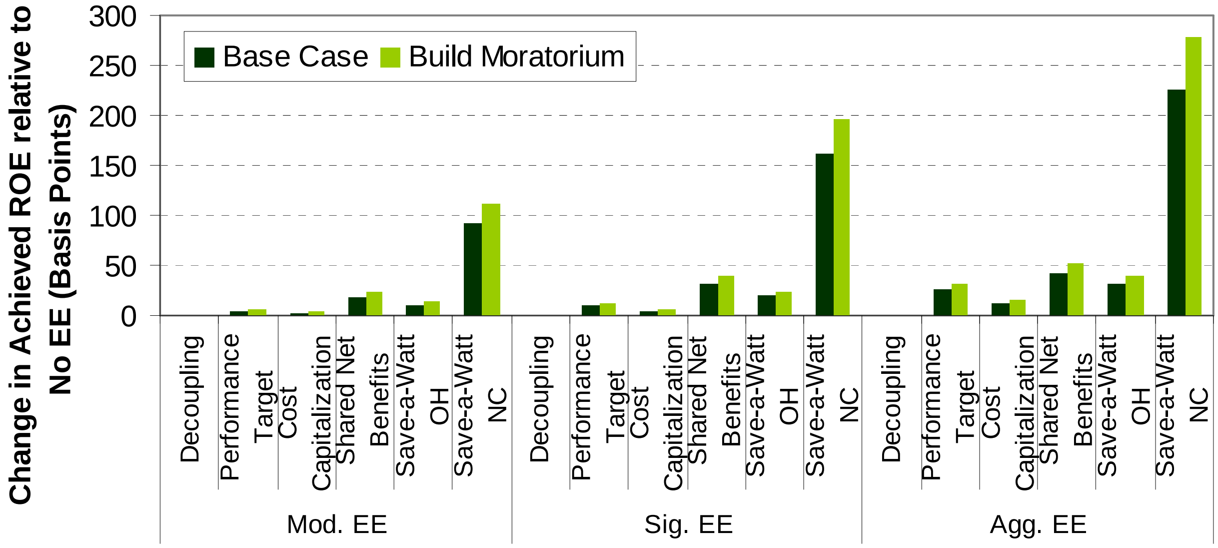


**Figure E- 14. Effect of decoupling and shareholder incentives on achieved ROE for Utility Build Moratorium case**

## E.3 Higher Cost Utility Sensitivity Case Results

There is great diversity in the cost structure of utilities in the Southwest (and in the US). Costs associated with a utility's previous investment decisions remain on the books for twenty years or more for major generation and transmission projects, which if ill-advised or unchecked from a cost-containment standpoint can impact retail rate levels for many years. Moreover, the degree of operational efficiency (e.g. labor costs, power plant heat rates, line losses) can also have a significant impact on the level of current and future retail rates.

In this sensitivity case, we explore the impact from instituting the three EE portfolios at a utility that has considerably higher costs (and rates) than the prototypical utility under base case assumptions. Historically, the utility in our Higher Cost sensitivity case made capacity investment decisions that turned out to be more expensive; thus its rate base is ~40% higher than the prototypical utility in the base case. From an operations standpoint, the High Cost utility is also rather inefficient, spending nearly 70% more than the prototypical utility on its annual O&M budget in the base case. When combined, these two factors result in the High Cost sensitivity case producing a first year average retail rate that is 2 ¢/kWh higher than the prototypical utility under base case assumptions (i.e., 11.1 ¢/kWh in High Cost sensitivity case and 9.1 ¢/kWh in the Base Case).

The Benefits Calculator assumes that future investments in energy efficiency programs do not have an impact on historic capital expenditures or future O&M budgets. Since all other going forward costs are the same across the two cases (i.e., fuel and purchased power, capital expenditure budgets), identical reductions in peak demand and energy from EE produce identical cost savings to the utility. The change in the revenue requirement for each component piece of the cost of service is the same even though the High Cost utility and the Base Case utility start at very different retail rate levels (see Figure E- 15). In spite of the differences in cost of service and initial retail rates between the High Cost utility and the prototypical utility in the base case, they both produce identical cost reductions in the revenue requirement when EE is implemented from their "business-as-usual" No EE levels: $1.08B, $1.66B, and $2.32B for the Moderate, Significant and Aggressive EE portfolios respectively (see diamonds linked to right axis of Figure E-15). With no difference across the three sensitivity cases in the change in rate base-related costs (as well as non-'rate base" related costs) from implementing energy efficiency, there can be no difference in the impact on authorized earnings.

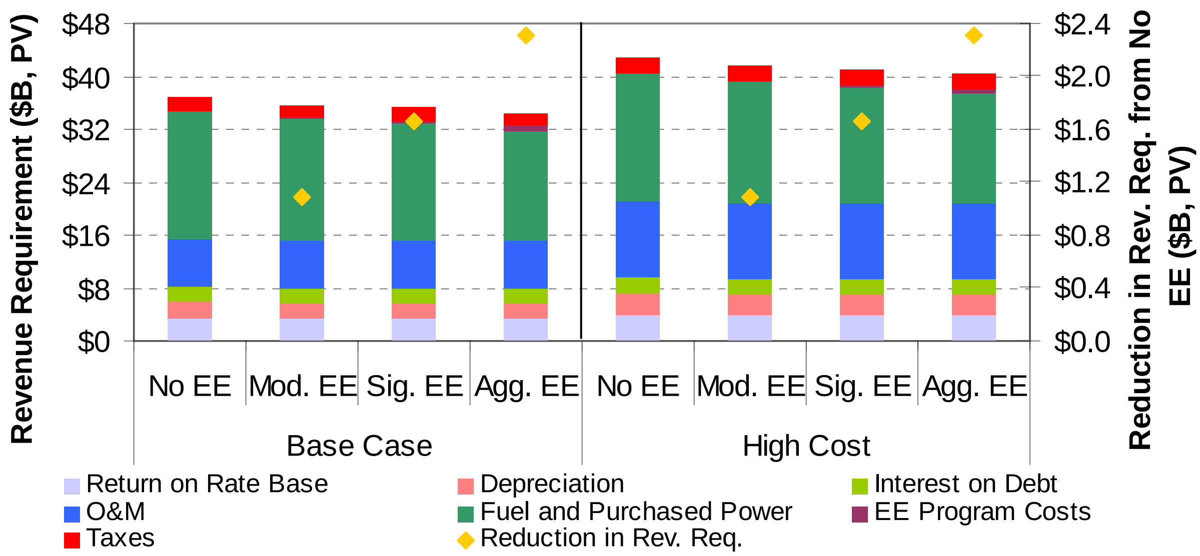


**Figure E- 15. 20-Year revenue requirement for High Cost Utility sensitivity case**

# Appendix F. Designing shareholder incentives to achieve specific policy goals

In Appendix F, we explore a different approach to designing shareholder incentives that focuses on a regulatory commission that is interested in achieving specific policy goals: capturing the net resource benefits of energy efficiency for ratepayers and establishing a sustainable business model that encourages utilities to pursue energy efficiency aggressively.

## F.1 Designing shareholder incentives that provides shareholders with an opportunity to achieve a specified increase in return-on-equity

In this section, we address the situation where the PUC wants to offer our prototypical utility the opportunity to achieve a pre-specified, targeted increase in the utility's after-tax ROE (e.g., 10, 20 or 30 basis point increase in ROE when savings goals are reached compared to the "business-as-usual" (BAU) No EE case.[84] The regulatory commission is interested in understanding the potential impacts of changing the target earnings basis of each shareholder incentive mechanism compared to a BAU case without energy efficiency.

Under the initial Performance Target incentive mechanism, the prototypical utility receives an additional 10% of program administration and measure incentive costs for achieving a program savings target. In Figure F- 1, we show the required percentage of additional program costs that must be provided to the prototypical utility (on an after-tax basis) if it implements the three EE portfolios for the utility to achieve a 10, 20 or 30 basis point increase in ROE compared to the business-as-usual No EE case. The moderate EE portfolio requires a higher percentage of additional program costs for the Performance Target incentive in order to achieve the same increase in ROE basis points as an EE portfolio that achieves deeper savings because the moderate EE portfolio has a lower budget. For example, to affect a 20 basis point increase from the BAU ROE, the prototypical southwest utility would have an earnings basis equal to an additional 46% of program cost for achieving the Moderate EE savings goals. If the utility reached the Significant EE savings goals, then the regulatory commission could set the earnings basis at an amount equal to an additional 25% of program costs. It is not clear that a Performance Target mechanism would be politically acceptable to some stakeholders (e.g. customer groups) in cases where they represented a high share of additional program costs (e.g. the earnings basis would represent an additional ~46-65% of program costs for the Moderate EE portfolio if shareholder incentives were to provide a 20-30 basis point increase).

[84] The PUC could also decide to institute a decoupling mechanism and also offer the utility an opportunity to increase earnings by a targeted amount (e.g. 10 or 20 basis points) through a shareholder incentive that provided rewards for successful achievement of EE goals.

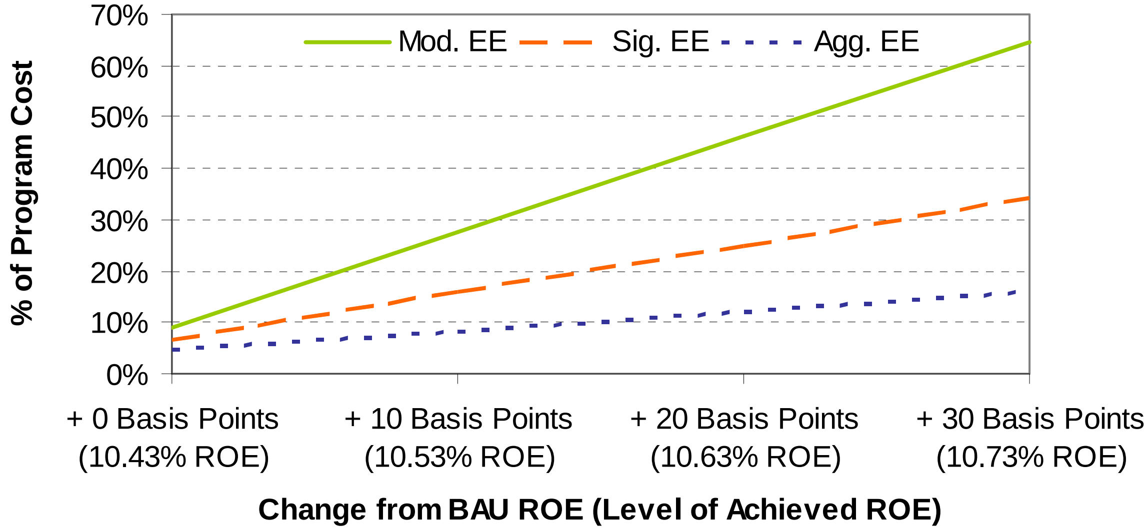


**Figure F- 1. Relationship between Performance Target mechanism earnings basis and change in ROE**

Under the initial Shared Net Benefits incentive mechanism, the prototypical utility retains 15% of the net benefits from the portfolio of energy efficiency programs. In Figure F- 2, we show the percentage of net resource benefits to be retained by the utility if the utility implements the three EE portfolios in order to achieve a 10, 20 or 30 basis point increase in ROE compared to the business-as-usual No EE case. Compared to the Performance Target mechanism, there is a narrower range in the required earnings basis: the share of net resource benefits ranges from ~9 to ~30% for a 10-30 basis point increase for all 3 EE portfolios. For example, the share of net resource benefits offered to the utility to achieve a 10 to 30 basis point increase in ROE is quite similar for the Significant and Aggressive EE portfolio. The Shared Net Benefits incentive has the desirable property that it may be politically acceptable to stakeholders to adopt an earnings basis level (e.g. 15% of net resource benefits) that could remain in place for some period of time as it would allow the utility to increase its ROE as it achieves higher levels of EE savings (e.g. ROE increases by 13 to 23 basis points as the utility moves from a Moderate to Aggressive EE portfolio).

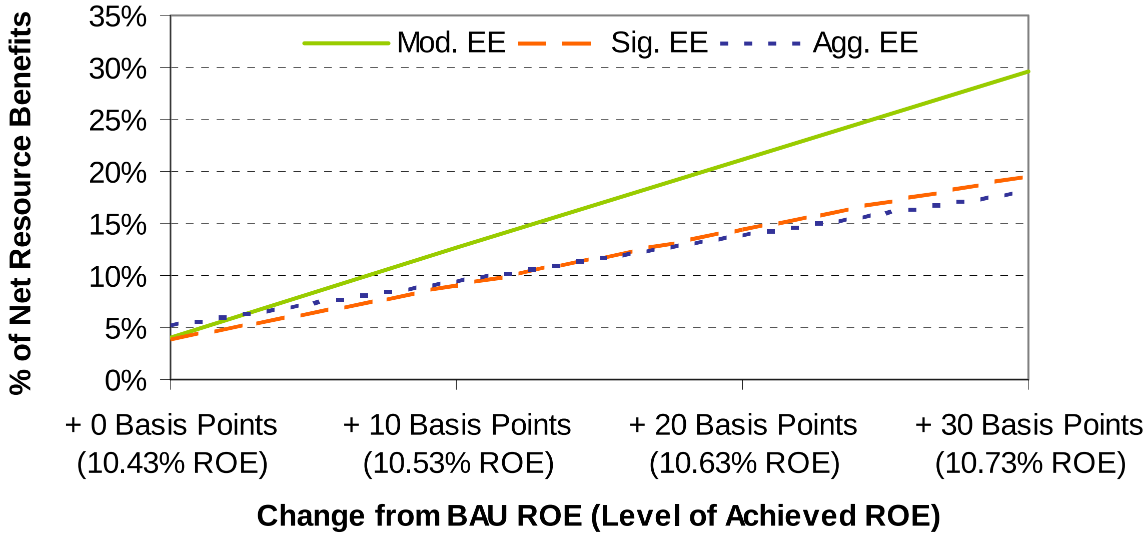


**Figure F- 2. Relationship between Shared Net Benefits earnings basis and change in ROE**

Under the initial Save-A-Watt NC mechanism, the prototypical utility capitalizes and receives 90% of the present value of avoided costs over the lifetime of installed EE measures.[85] In Figure F- 3, we show the percentage of capitalized avoided costs to be retained by the prototypical utility for implementing the three EE portfolios in order to achieve a 10, 20 or 30 basis point increase in ROE compared to the business-as-usual No EE case. Because the Save-A-Watt NC mechanism covers program costs, lost revenue, as well as an incentive payment, the achieved return on equity with Save-A-Watt is directly dependent upon the level of avoided cost benefits provided to the utility relative to the cost of the EE programs. If the prototypical utility can achieve the savings goals based on our EE program cost assumptions, then an earnings basis set at 33% of avoided cost benefits would produce a 10 basis point increase in ROE for implementing the Moderate EE portfolio, while an earnings basis set at 36% of the avoided cost benefits would produce a 20 basis point increase in ROE for the Significant EE portfolio.[86] These results also suggest that the levels of avoided cost benefits provided to the prototypical utility are much lower than the 90% requested by Duke Carolina, assuming that a 10-30 basis point increase in ROE is the level of earnings increase being considered by a regulatory commission (Duke 2007).

[85] We do not include an analysis of the Save-A-Watt OH proposal in this section, because that mechanism includes an earnings cap, a share of gross benefits, and a lost revenue recovery mechanism. Thus, there are too many elements to the mechanism that can change to make this type of analysis meaningful.

[86] Recall that under Save-A-Watt, the utility earnings are at risk (and could be lower than expected) if EE program costs are higher than forecast or if actual, verified savings are lower than engineering estimates of savings.

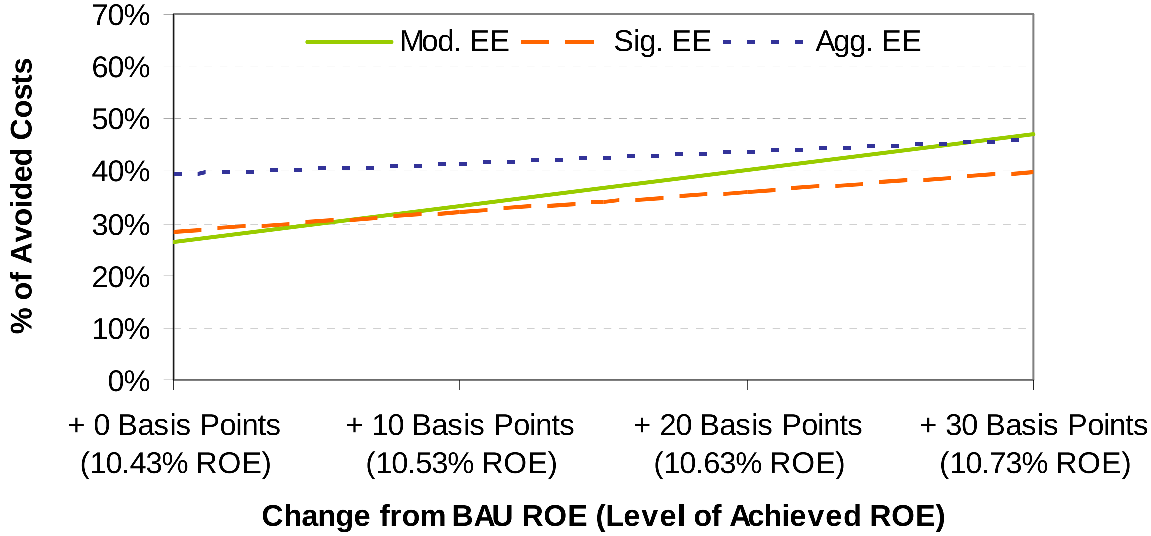


**Figure F- 3. Relationship between Save-a-Watt NC earnings basis and change in ROE**

Under the initial Cost Ccapitalization mechanism, the prototypical utility receives a bonus for energy efficiency investments and is allowed to increase its authorized ROE (10.75%) by 500 basis points on those investments. In Figure F- 4, we show the return on equity bonus that must be provided to the prototypical utility (on an after-tax basis) for energy efficiency investments if it implements the three EE portfolios for the utility to achieve a 10, 20 or 30 basis point increase in ROE compared to the business-as-usual No EE case. A Cost Capitalization incentive mechanism produces a larger marginal increase in ROE for the same earnings basis level (i.e., return on equity bonus) as the degree of EE savings increases. For example, a 1,000 basis point ROE Bonus level would produce a change in the prototypical utility's after-tax ROE equal to 1 basis point for the Moderate EE portfolio, 3 basis points for the Significant EE portfolio, and 12 basis points for the Aggressive EE portfolio.

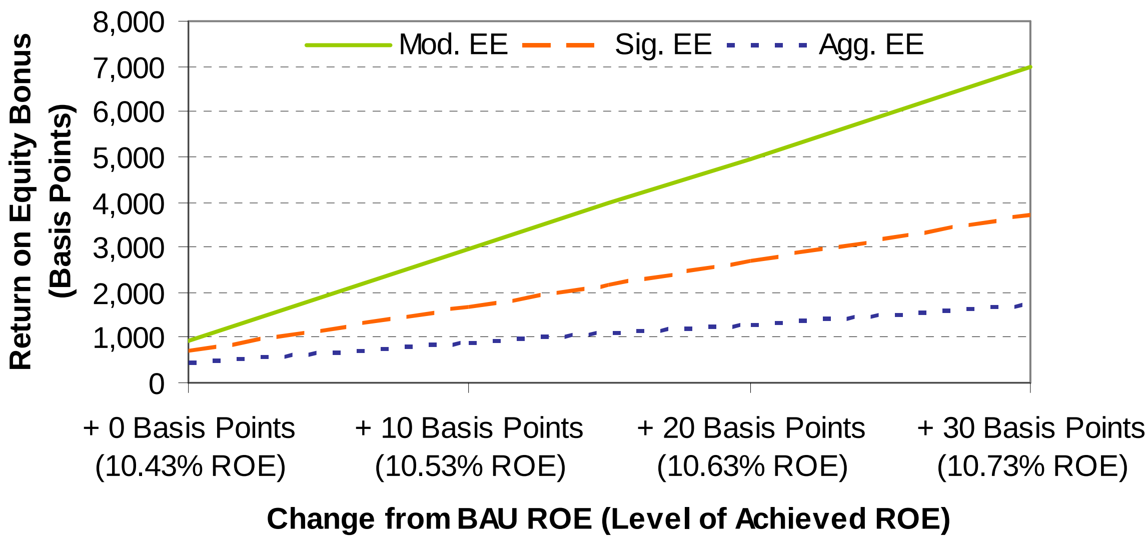


**Figure F- 4. Relationship between Cost Capitalization earnings basis and change in ROE**

In assessing the relative merits of incentive proposals, state regulators may consider the potential impact of a shareholder incentive mechanism on the overall level of EE program costs and equity issues such as the sharing of net resource benefits from implementing an EE portfolio between shareholders and customers. In Table F- 1, we show the four shareholder incentive mechanisms expressed in terms of the shareholder incentive as a percent of program cost as the size of the EE portfolio increases and would highlight the following results.[87]

First, the Performance Target, Shared Net Benefits and Save-a-Watt NC mechanisms all produce identical pre-tax incentive payments as a percent of total program costs when the mechanisms are designed to achieve a specific level of ROE for a specified EE portfolio. This occurs because the utility issues no additional equity with these mechanisms; thus, every after-tax dollar that is received from ratepayers for the incentive contributes directly to increasing ROE. However, the Cost Capitalization mechanism must generate a larger amount of money to meet the same rate of return because the utility typically issues additional equity (and debt) to fund the EE program costs and the associated incentive. Thus, with a Cost Capitalization mechanism, some of the upside impact on the utility's achieved ROE is mitigated because, although earnings increase, more equity is outstanding (which dampens the increase in ROE).

**Table F- 1. Pre-tax shareholder incentive as a percent of total EE program costs (Shareholder perspective)**

| | | | | Pre-Tax Incentive as % of Program Cost | | | |
|---|---|---|---|---|---|---|---|
| | | | **Achieved ROE** | **Performance Target** | **Shared Net Benefits** | **Save-a-Watt** | **Cost Capitalization** |
| **Mod. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 14% | 14% | 14% | 21% |
| | | + 10 Basis Pts. | 10.53% | 44% | 44% | 44% | 51% |
| | | + 20 Basis Pts. | 10.63% | 74% | 74% | 74% | 81% |
| | | + 30 Basis Pts. | 10.73% | 104% | 104% | 104% | 111% |
| **Sig. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 11% | 11% | 11% | 18% |
| | | + 10 Basis Pts. | 10.53% | 26% | 26% | 26% | 32% |
| | | + 20 Basis Pts. | 10.63% | 40% | 40% | 40% | 47% |
| | | + 30 Basis Pts. | 10.73% | 55% | 55% | 55% | 63% |
| **Agg. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 7% | 7% | 7% | 14% |
| | | + 10 Basis Pts. | 10.53% | 13% | 13% | 13% | 20% |
| | | + 20 Basis Pts. | 10.63% | 19% | 19% | 19% | 27% |
| | | + 30 Basis Pts. | 10.73% | 26% | 26% | 26% | 33% |

Second, the "+ 0 basis point" level provides the regulatory agency and utility with information on the shareholder incentive as a percent of program costs that allows the utility to be indifferent to implementing energy efficiency, but does not provide a positive financial incentive. With the exception of Cost Capitalization, the other three shareholder incentive mechanisms represent

[87] If a decoupling mechanism were implemented in conjunction with one of the non-"Save-a-Watt" mechanisms, the incentive payment required to achieve the necessary increase in ROE would be less.

between 7-14% of program costs across all EE portfolios if the utility's ROE target is set at the BAU No EE case.

Third, as you move from Moderate to Aggressive EE portfolios, the shareholder incentives represents a declining percent of program costs at a specified target basis point increase (e.g. 20 basis points). For example, for Performance Target, Shared Net Benefits or Save-A-Watt, the shareholder incentive would increase EE program costs by 74% for a Moderate EE portfolio but would only increase program costs by 19% for the Aggressive EE portfolio. The implicit message is that a targeted increase in ROE may have to scale with the size of the EE portfolio. It may be hard for customer groups to accept incentive mechanisms that offer 20-30 basis point increases in ROE, which also have the effect of increasing program costs by 70-104%. If some stakeholder groups believe that shareholder incentives should not increase program costs by more than X% (e.g. 15-20%), then they may also conclude that shareholder incentives are more acceptable if the utility implements a Significant or Aggressive EE portfolio. In any event, an analysis that links increases in the utility's actual ROE through specific incentive mechanisms to their impact on EE program costs may be an effective way for regulators to assess clearly the trade-offs in incentive design, acceptable earnings targets, and level of EE effort necessary for additional earnings.

In addition to their impact on program costs, regulatory agencies and other stakeholders may also be interested in how the design of shareholder incentive mechanisms influences the sharing of net resource benefits between utility shareholders and ratepayers. In Table F- 2, we show the ratepayer share of net resource benefits across the three EE portfolios for four incentive mechanisms with varying increases in the ROE earnings target. We would highlight the following results.

First, ratepayers receive 73 to 88% of the net resource benefits if the utility successfully achieves the savings goals in the Significant and Aggressive EE portfolios under most incentive mechanisms (except for Cost Capitalization) and target increases in ROE (e.g. 10-30 basis point increase in ROE). The ratepayers' share of net resource benefits is in the 58-70% range if the utility has the opportunity to increase earnings by 20-30 basis points for implementing the Moderate EE portfolio.

Second, if the regulatory agency wants the shareholder incentive mechanisms to allow the utility to increase its BAU ROE by 10 basis points, than ratepayers receive 82-88% of the net resource benefits (except for the Cost Capitalization mechanism where ratepayers share is 3-7 percentage points lower). As the ROE earnings target increases for the same level of achieved EE savings, the incentive payment to shareholders increases and ratepayers' share of net resource benefits decreases. For example, if the utility implements the Significant EE portfolio, ratepayers receive 80% of the net resource benefits if the ROE earnings target is set at a 20 basis point increase, while ratepayers receive 73% of net resource benefits at a 30 basis point increase in ROE (except for Cost Capitalization).

Third, in the case of Save-A-Watt (NC), in order for ratepayers of our southwest utility to receive a significant share of the net resource benefits (i.e., 70-88%), then the design of Save-A-Watt has to be significantly changed, such that the utility would recover revenues based on ~30-40% of avoided costs. This would provide the Southwest utility with an opportunity to increase their ROE by 10-20 basis points across the three EE portfolios.

**Table F- 2. Ratepayer Share of Net Resource Benefits (Shareholder perspective)**

| | | | | Ratepayer Share of Net Resource Benefits | | | |
|---|---|---|---|---|---|---|---|
| | | | Achieved ROE | Performance Target | Shared Net Benefits | Save-a-Watt | Cost Capitalization |
| **Mod. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 94% | 94% | 94% | 92% |
| | | + 10 Basis Pts. | 10.53% | 82% | 82% | 82% | 80% |
| | | + 20 Basis Pts. | 10.63% | 70% | 70% | 70% | 68% |
| | | + 30 Basis Pts. | 10.73% | 58% | 58% | 58% | 55% |
| **Sig. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 95% | 95% | 95% | 91% |
| | | + 10 Basis Pts. | 10.53% | 87% | 87% | 87% | 84% |
| | | + 20 Basis Pts. | 10.63% | 80% | 80% | 80% | 77% |
| | | + 30 Basis Pts. | 10.73% | 73% | 73% | 73% | 69% |
| **Agg. EE** | BAU ROE | + 0 Basis Pts. | 10.43% | 93% | 93% | 93% | 87% |
| | | + 10 Basis Pts. | 10.53% | 88% | 88% | 88% | 81% |
| | | + 20 Basis Pts. | 10.63% | 82% | 82% | 82% | 75% |
| | | + 30 Basis Pts. | 10.73% | 76% | 76% | 76% | 70% |

## F.2 Designing shareholder incentives that provides ratepayers with an opportunity to achieve a certain share of net resource benefits

In the previous section, we examined the design of various shareholder incentive mechanisms if a PUC is interested in providing a utility with an opportunity to achieve a specifed increase in its ROE for achieving savings targets. In this section, we analyze the design of shareholder incentive mechanisms if a PUC has a policy objective of ensuring that ratepayers retain a pre-specified share of net resource benefits (e.g., 70%, 80%, etc.) if the utility successfully implements its portfolio of energy efficiency programs.

Under the initial Performance Target mechanism, the prototypical utility receives an additional 10% of program administration and measure incentive costs for achieving a program savings target. In Figure F- 5, we show the required percentage of additional program costs that must be provided to the prototypical utility (on an after-tax basis) if it implements the three EE portfolios for ratepayers to retain 60% to 90% of the net resource benefits associated with the EE programs. The moderate EE portfolio requires a higher percentage of additional program costs for the Performance Target incentive in order to achieve the same ratepayer share of net resource benefits as an EE portfolio that achieves deeper savings. For example, to allow ratepayers to retain 80% of the net resource benefits, the prototypical southwest utility would have an earnings basis equal to an additional 31% of program costs for achieving the Moderate EE savings goals. If the utility reached the Significant EE savings goals, then the PUC could set the earnings basis at an amount equal to an additional 25% of program costs. It is not clear that a performance target mechanism would be politically acceptable to some stakeholders in cases where they represented a high share of additional program costs (e.g. the earnings basis would represent an additional ~47-62% of program costs for the Moderate EE portfolio if shareholder incentives were to provide ratepayers with only 60%-70% of net resource benefits).

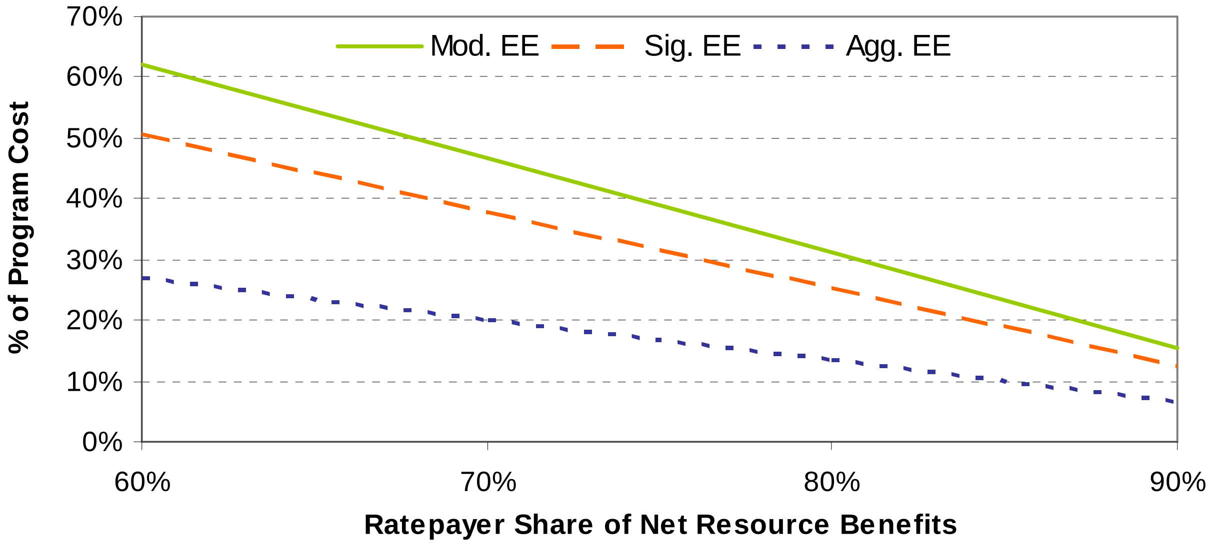


**Figure F- 5. Relationship between Performance Target mechanism earnings basis and ratepayer share of net resource benefits**

Under the initial Shared Net Benefits mechanism, the prototypical utility retains 15% of the net benefits from the portfolio of energy efficiency programs. In Figure F- 2, we show the percentage of net resource benefits to be retained by the utility if the utility implements the three EE portfolios in order for ratepayers to retain from 60% to 90% of the net resource benefits from EE. Because this mechanism is derived from the net resource benefits, there are minor differences in the earnings basis across savings levels, due entirely to the remittance of taxes on the utility's earnings from this shareholder incentive mechanism.[88]

[88] Because the net resource benefits are effectively monetized and converted into increased earnings for the utility via the shareholder incentive, there are now three parties that must share the net resource benefits: shareholders, ratepayers and the government by way of taxes. This explains why the earnings basis for this mechanism when added to the share of net resource benefits retained by ratepayers is less than 100%.

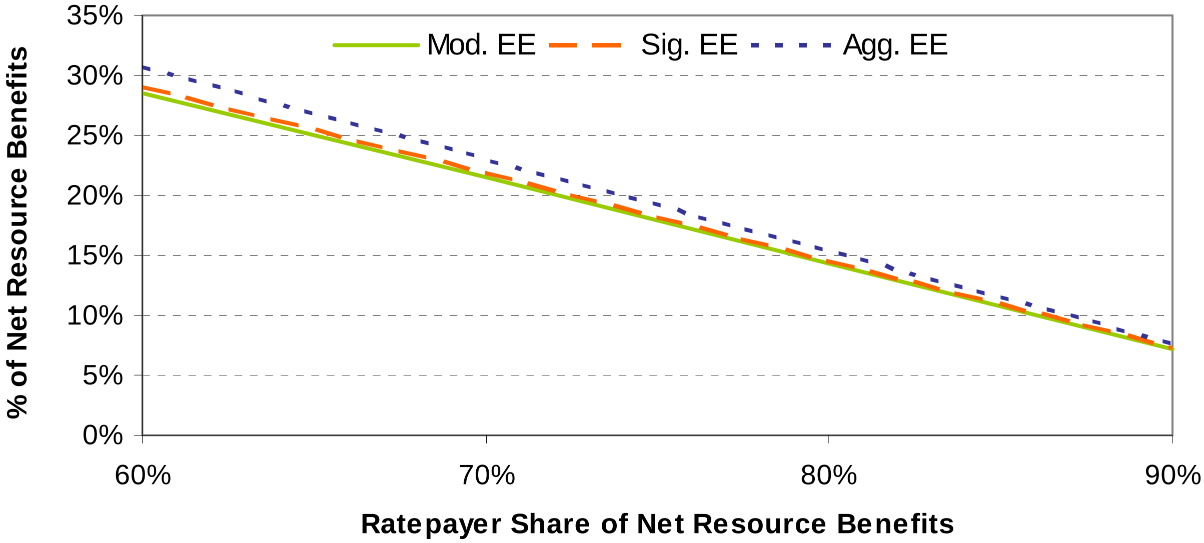


**Figure F- 6. Relationship between Shared Net Benefits earnings basis and ratepayer share of net resource benefits**

Under the initial Save-A-Watt NC mechanism, the prototypical utility capitalizes and receives 90% of the present value of avoided costs over the lifetime of installed EE measures. In Figure F- 7, we show the percentage of capitalized avoided costs to be retained by the prototypical utility for implementing the three EE portfolios under a revised Save-a-Watt NC mechanism that gives ratepayers from 60% to 90% of the associated net resources benefits. Because the Save-A-Watt NC mechanism covers program costs, lost revenue, as well as an incentive payment, the utility's achieved share of net resource benefits with Save-A-Watt is directly dependent upon the level of avoided cost benefits provided to the utility relative to the cost of the EE programs. If the prototypical utility can achieve the savings goals based on our EE program cost assumptions, then an earnings basis set at 34% of avoided cost benefits would provide 80% of the net resource benefits associated with implementing the Moderate EE portfolio to ratepayers, while an earnings basis set at 36% of the avoided cost benefits would produce a comparable ratepayer share of net resource benefits for the Significant EE portfolio. These results also suggest that the levels of avoided cost benefits provided to the prototypical utility are much lower than the 90% requested by Duke Carolina, assuming that ratepayers retain between 60% and 90% of the net resource benefits (Duke 2007).

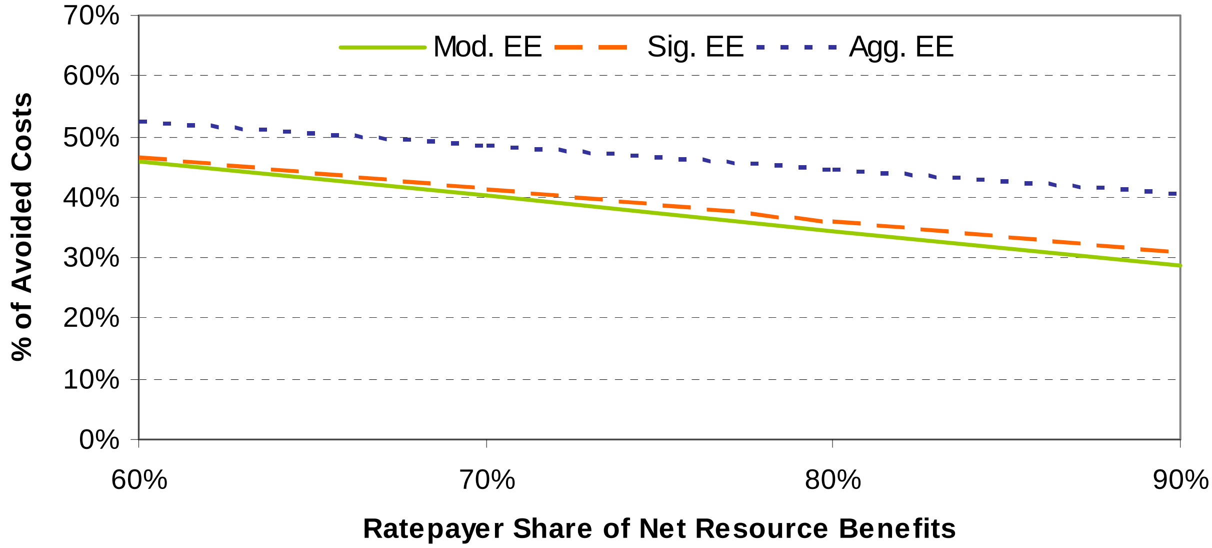


**Figure F- 7. Relationship between Save-a-Watt NC earnings basis and and ratepayer share of net resource benefits**

Under the initial Cost Capitalization mechanism, the prototypical utility receives a bonus for energy efficiency investments and is allowed to increase its authorized ROE (10.75%) by 500 basis points on those investments. In Figure F- 8, we show the return on equity bonus that must be provided to the prototypical utility (on an after-tax basis) for energy efficiency investments if it implements the three EE portfolios for ratepayers to retain from 60% to 90% of the net resource benefits.  A Cost Capitalization mechanism produces a smaller share of net resource benefits to ratepayers for the same earnings basis level (i.e., return on equity bonus) as the degree of EE savings increases.  For example, a 1,000 basis point ROE Bonus level would provide ratepayers with 91% of the net resource benefits for the Moderate EE portfolio and 80% of the net resource benefits for the Aggressive EE portfolio.

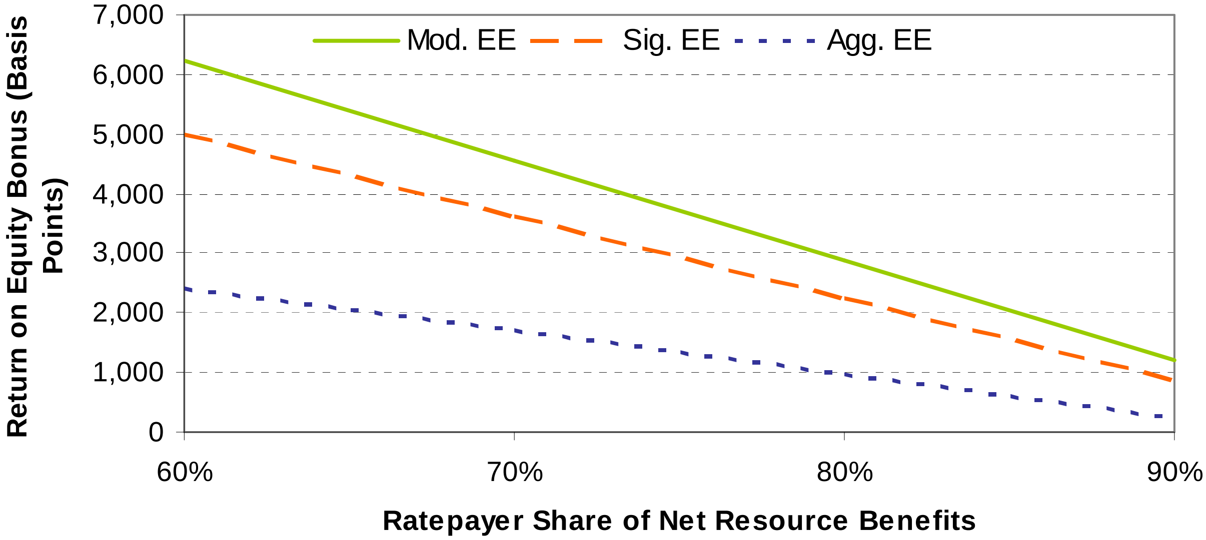


**Figure F- 8. Relationship between Cost Capitalization earnings basis and and ratepayer share of net resource benefits**

In assessing the relative merits of incentive proposals, state regulators may consider the potential impact of a shareholder incentive mechanism on the overall level of EE program costs and degree that it impacts a utility's return on equity. In Table F- 3, we show the four shareholder incentive mechanisms expressed in terms of the shareholder incentive as a percent of program cost as the size of the EE portfolio increases and would highlight the following results.[89]

First, all four shareholder incentive mechanisms produce identical pre-tax incentive payments as a percent of total program costs when the mechanisms are designed to provide ratepayers with a specified share of the net resource benefits.  Since the net resource benefits are based on the EE portfolio under consideration, the share that goes to ratepayers is identical regardless of the mechanism under consideration.  The proportion of net resource benefits that the utility receives by way of an incentive payment must also be same across the different mechanisms.

[89] If a decoupling mechanism were implemented in conjunction with one of the non-"Save-a-Watt" mechanisms, the incentive payment required to achieve the necessary increase in ROE would be less.

**Table F- 3. Pre-tax shareholder incentive as a percent of total EE program costs (Ratepayer perspective)**

| | Ratepayer Share of Net Resource Benefits | Pre-Tax Incentive as % of Program Cost | | | |
|---|---|---|---|---|---|
| | | Performance Target | Shared Net Benefits | Save-a-Watt | Cost Capitalization |
| Mod. EE | 60%. | 100% | 100% | 100% | 100% |
| | 70%. | 75% | 75% | 75% | 75% |
| | 80% | 50% | 50% | 50% | 50% |
| | 90% | 25% | 25% | 25% | 25% |
| Sig. EE | 60%. | 81% | 81% | 81% | 81% |
| | 70%. | 61% | 61% | 61% | 61% |
| | 80% | 41% | 41% | 41% | 41% |
| | 90% | 20% | 20% | 20% | 20% |
| Agg. EE | 60%. | 43% | 43% | 43% | 43% |
| | 70%. | 33% | 33% | 33% | 33% |
| | 80% | 22% | 22% | 22% | 22% |
| | 90% | 11% | 11% | 11% | 11% |

Second, as you move from Moderate to Aggressive EE portfolios, the shareholder incentives represents a declining percent of program costs at a specified ratepayer share of net resource benefits (e.g. 80%). For example, for all four shareholder incentive mechanisms, the shareholder incentive would increase EE program costs by 50% for a Moderate EE portfolio but would only increase program costs by 22% for the Aggressive EE portfolio when 80% of the net resource benefits are retained by ratepayers. The implicit message is that an attempt to ensure ratepayers receive a targeted share of net resource benefits produced by energy efficiency may have to scale with the size of the EE portfolio savings goal. It may be hard for customer groups to accept incentive mechanisms that provide utility's with 40% of the net resource benefits, which also have the effect of increasing program costs by 43-100%. If some stakeholder groups believe that shareholder incentives should not increase program costs by more than X% (e.g. 15-20%), then they may also conclude that shareholder incentives are more acceptable in situations where the utility implements a Significant or Aggressive EE portfolio. In any event, an analysis that links increases in ratepayer's share of net resource benefits through specific incentive mechanisms to their impact on EE program costs may be an effective way for regulators to assess clearly the trade-offs in incentive design, acceptable earnings targets, and level of EE effort necessary for additional earnings.

In addition to their impact on program costs, regulatory agencies and other stakeholders may also be interested in how the design of shareholder incentive mechanisms influences the utility's after-tax return on equity. In Table F- 4, we show the change in the utility's return on equity from the Business-as-usual case across the three EE portfolios for four incentive mechanisms with varying increases in the ratepayer share of net resource benefits. We would highlight the following results.

First, by providing the same additional revenue stream to the utility regardless of the incentive mechanism chosen, the difference in the incremental impact on the utility's return on equity will be driven by any changes in the outstanding level of equity. As noted above, Cost Capitalization results in additional equity being issued. So for the same incoming revenue associated with this incentive mechanism, the utility's achieved ROE is lower because more equity is outstanding. If too much equity is issued in relation to the additional earnings generated by the incentive mechanism, the utility can in fact be made worse off. Such is the case under the Aggressive EE portfolio when ratepayers keep 90% of the net resource benefits. In that instance, the utility would be unlikely to achieve that level of savings absent regulatory or legislative mandates and/or the imposition of penalties that exceeded this erosion of ROE.

Second, as the size of the EE savings increases, the contribution from a shareholder incentive to after-tax ROE is increased for the same share of net resource benefits. If ratepayers retain 80% of the net resource benefits, a utility would see its ROE increased by 12 basis points under a Moderate EE savings level but by twice that amount under the Aggressive EE portfolio. This provides a positive incentive for a utility to increase its commitment to energy efficiency as its bottom line will improve as it achieves deeper savings levels.

**Table F- 4. Change in After-Tax ROE from Business-as-usual case (Ratepayer perspective)**

| | Ratepayer Share of Net Resource Benefits | Change in After-Tax ROE from BAU (Basis Points) | | | |
|---|---|---|---|---|---|
| | | Performance Target | Shared Net Benefits | Save-a-Watt | Cost Capitalization |
| Mod. EE | 60%. | 29 | 29 | 29 | 26 |
| | 70%. | 20 | 20 | 20 | 18 |
| | 80% | 12 | 12 | 12 | 10 |
| | 90% | 4 | 4 | 4 | 1 |
| Sig. EE | 60%. | 48 | 48 | 48 | 42 |
| | 70%. | 34 | 34 | 34 | 29 |
| | 80% | 20 | 20 | 20 | 15 |
| | 90% | 7 | 7 | 7 | 2 |
| Agg. EE | 60%. | 59 | 59 | 59 | 47 |
| | 70%. | 41 | 41 | 41 | 29 |
| | 80% | 24 | 24 | 24 | 12 |
| | 90% | 6 | 6 | 6 | -5 |