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Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility

Technical Appendices

Peter Cappers, Charles Goldman, Michele Chait, George Edgar, Jeff Schlegel, Wayne Shirley

Environmental Energy Technologies Division

March 2009

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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

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.[1] 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.[2] Both APS and Nevada rely heavily upon power purchase agreements to serve their peak demand and electricity needs.

[1] 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.
[2] 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.

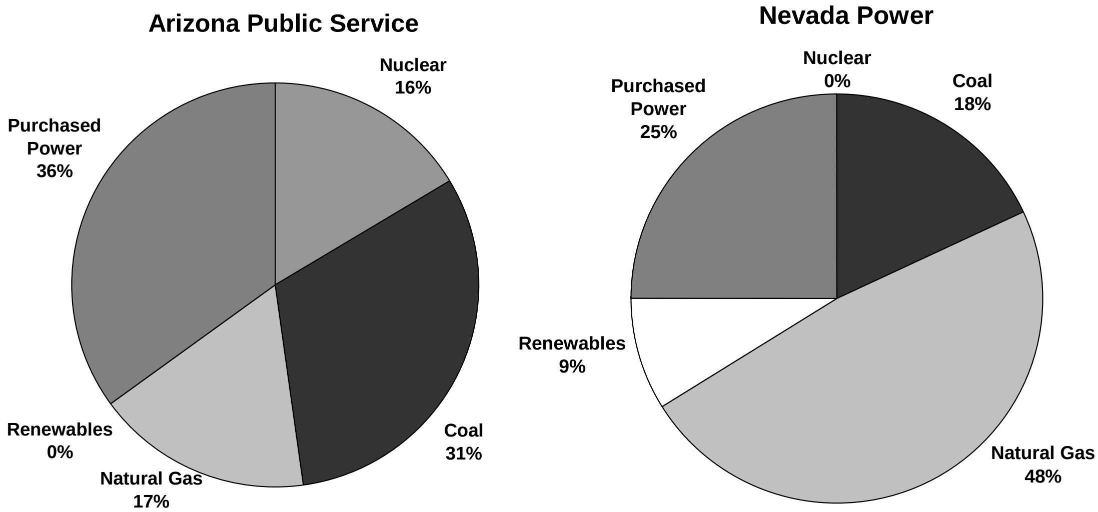

Figure A-1. Resource requirements to meet peak demand for Southwestern utilities

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%).

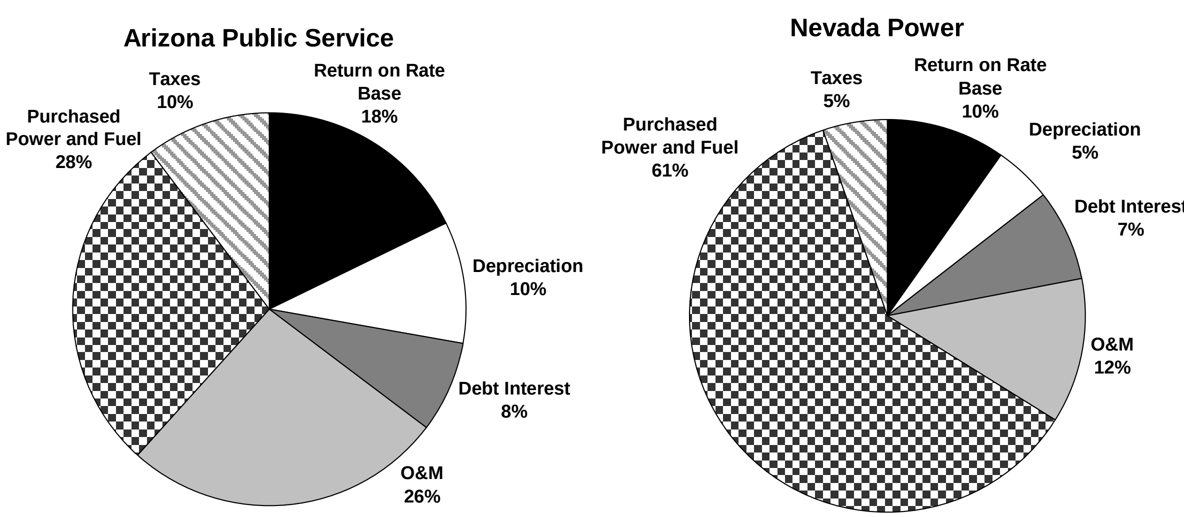

Figure A-2. Revenue requirement for Southwestern utilities

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.

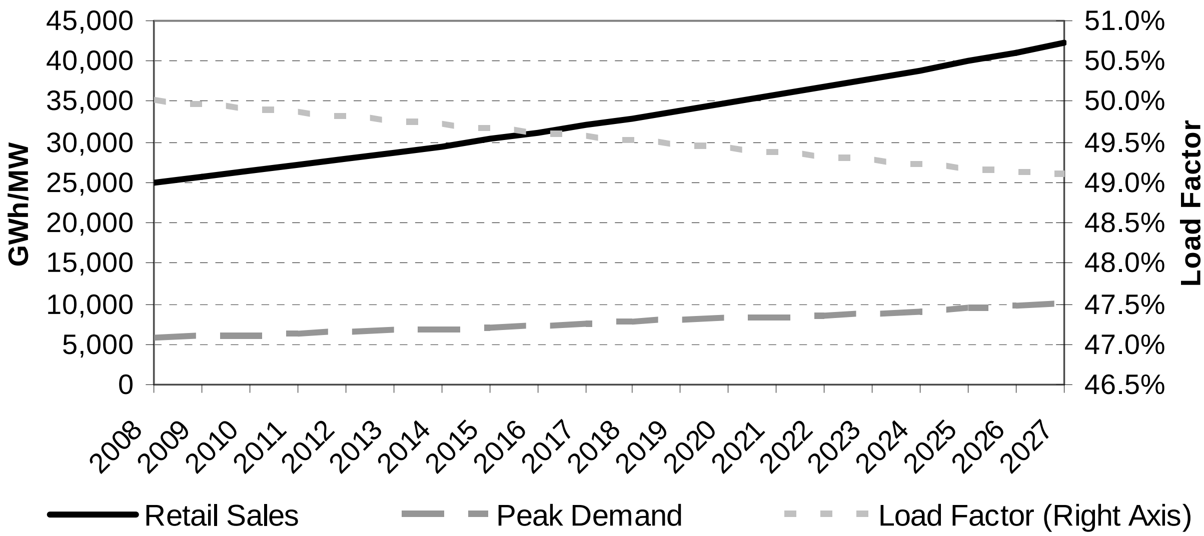

Figure A-3. Forecasted retail sales, peak demand and load factor at prototypical Southwest utility

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.[3] An iterative

[3] 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 overall

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).

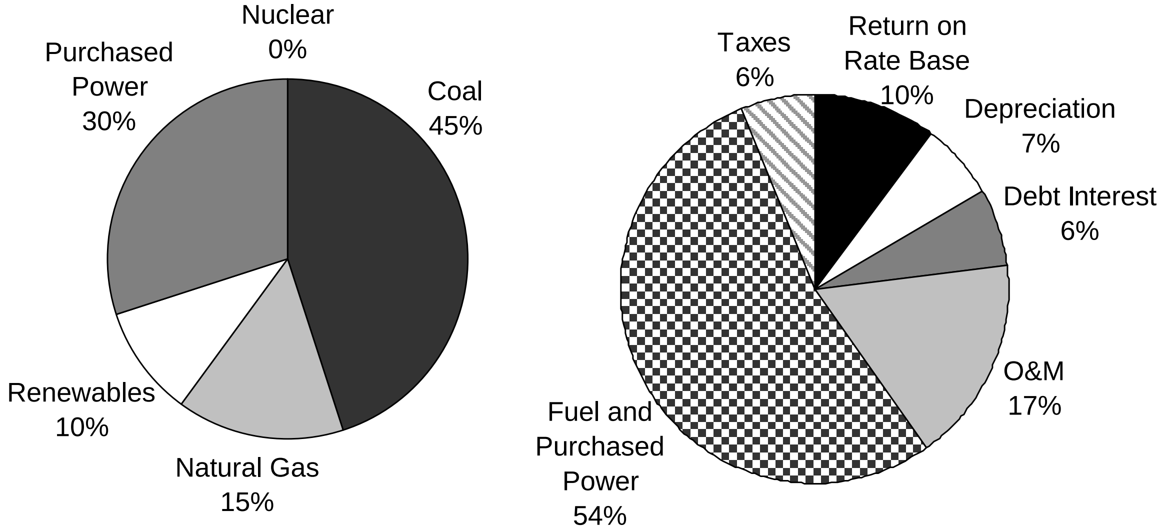

Figure A-4. First-year resource mix and revenue requirement for prototypical Southwest utility

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).[4] The introduction of these new

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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).

[4] 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.

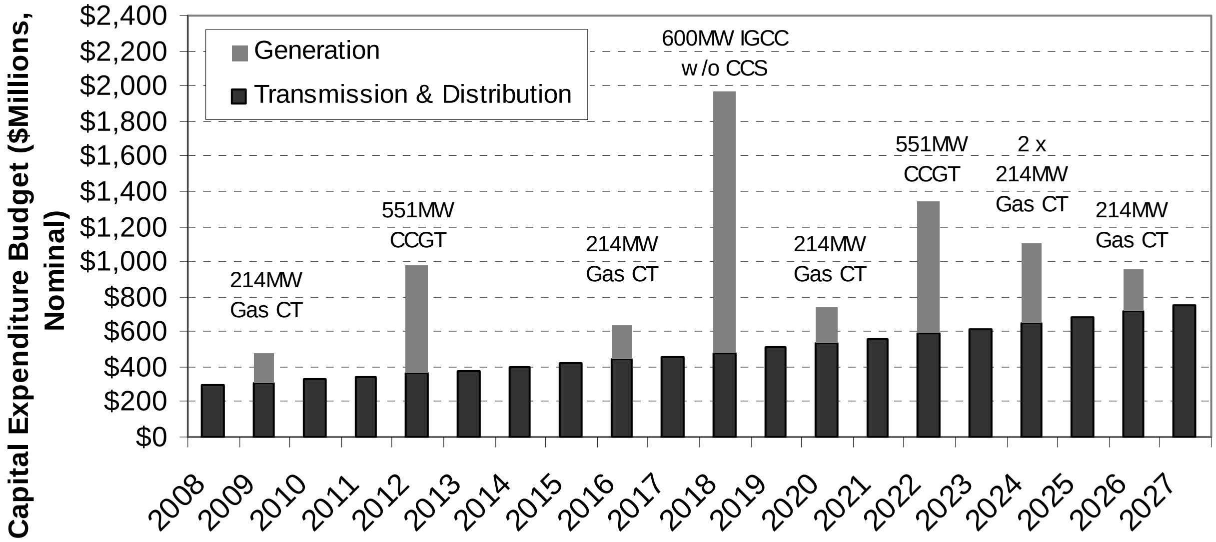

Figure A-5. Annual capital expenditure budget for prototypical Southwest utility

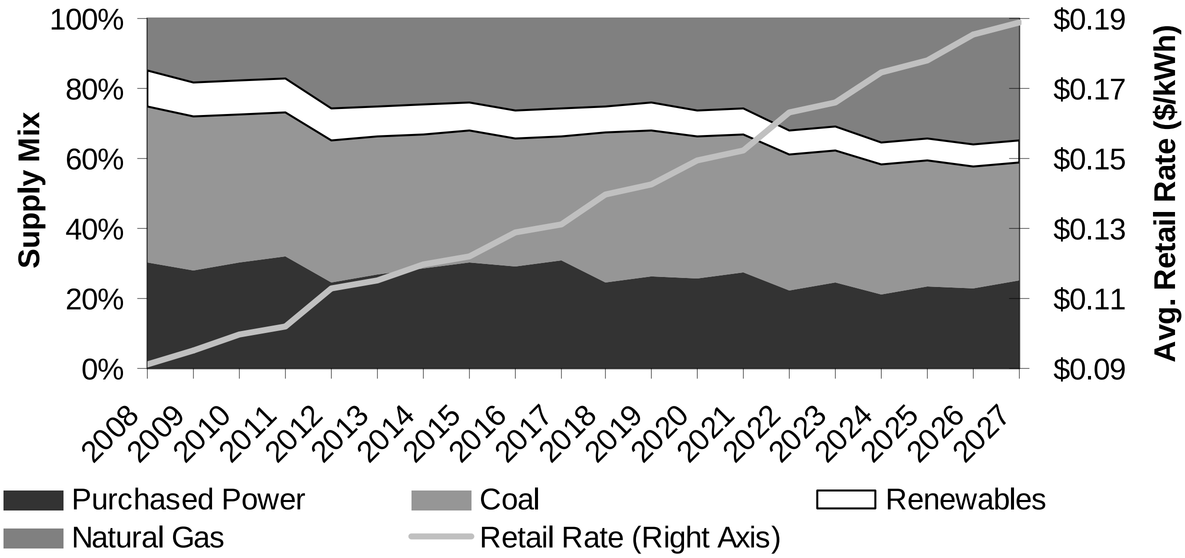

Figure A-6. Annual resource mix and average retail rates for prototypical Southwest utility

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%.[5] 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).

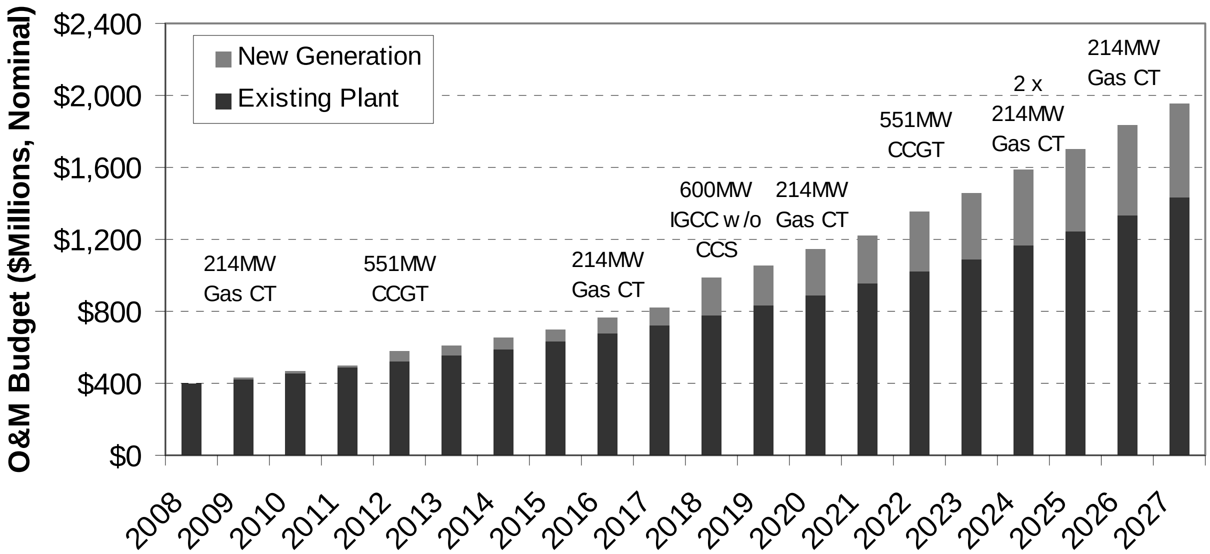

Figure A-7. Annual O&M budget for prototypical Southwest utility

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.

[5] 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.

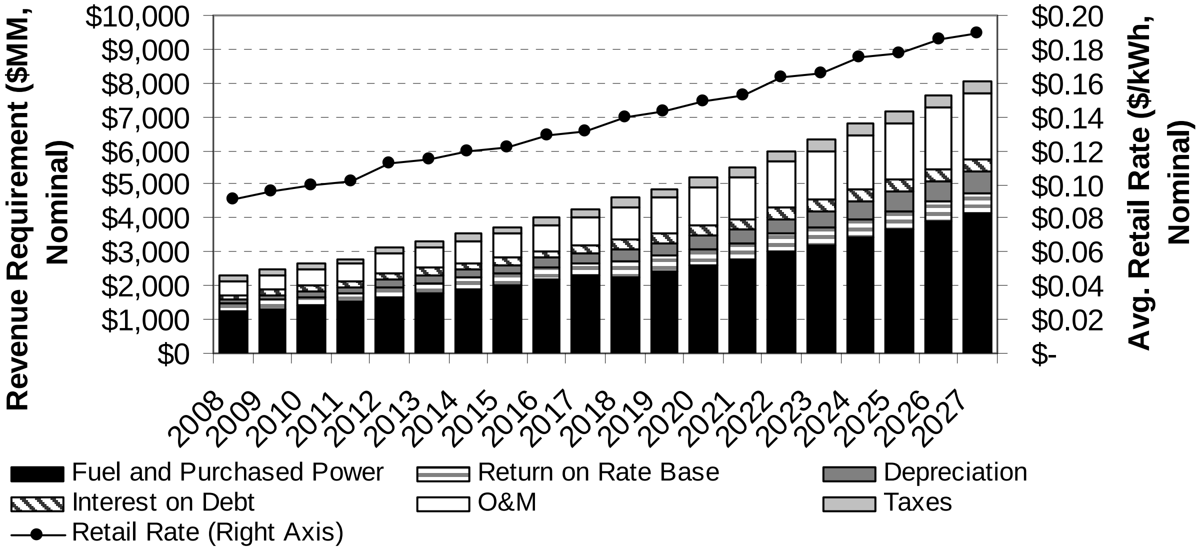

Figure A-8. Annual revenue requirement and average retail rate for prototypical Southwest utility

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).

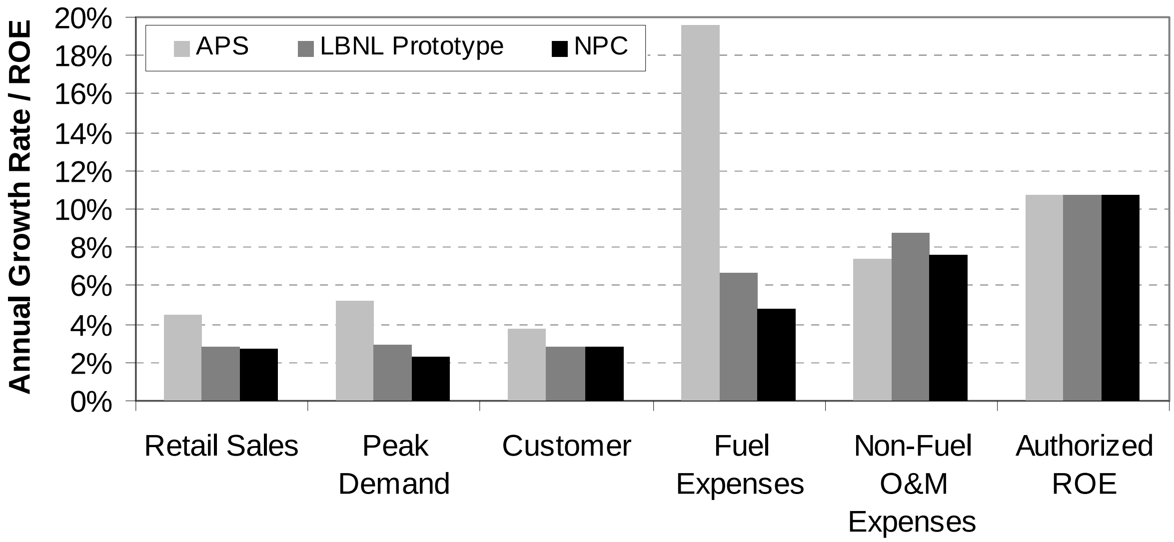

Figure A-9. Comparison of ROE and growth rates of key physical and operating characteristics for Southwest utilities

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.[6]

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.

[6] 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.[7] 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.

[7] 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 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). [8] 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.

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

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.[9] 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 ($ACTDC_{v,i}$),[10]

(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

[9] 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.
[10] 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) $ACI_{v,i} = PVAACT - \left(i \times DC_v\right) \;\; for\; i \in \left[1, j\right]$.

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

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).[11]

[11] 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.[12] 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.

[12] 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). [13] 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.

[13] 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*).[14]

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

[14] 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).[15] 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.[16] 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 ($ACTDC_{v,i}$),[17]

(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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[15] 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.
[16] 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.
[17] 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) $ACDRC_y = 75\% * \sum_{v=y-j}^{y} AACT_{v,y-v}$

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

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

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

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.[18]

[18] 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) $ECT_y = NIC_y - Max(NIC_y, CNI_y)$ 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).[19] 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.

[19] 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.[20] Table C-

[20] 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

	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 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).[21]

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

[21] 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**

[redacted]

	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**

[redacted]

	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.[22] 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.

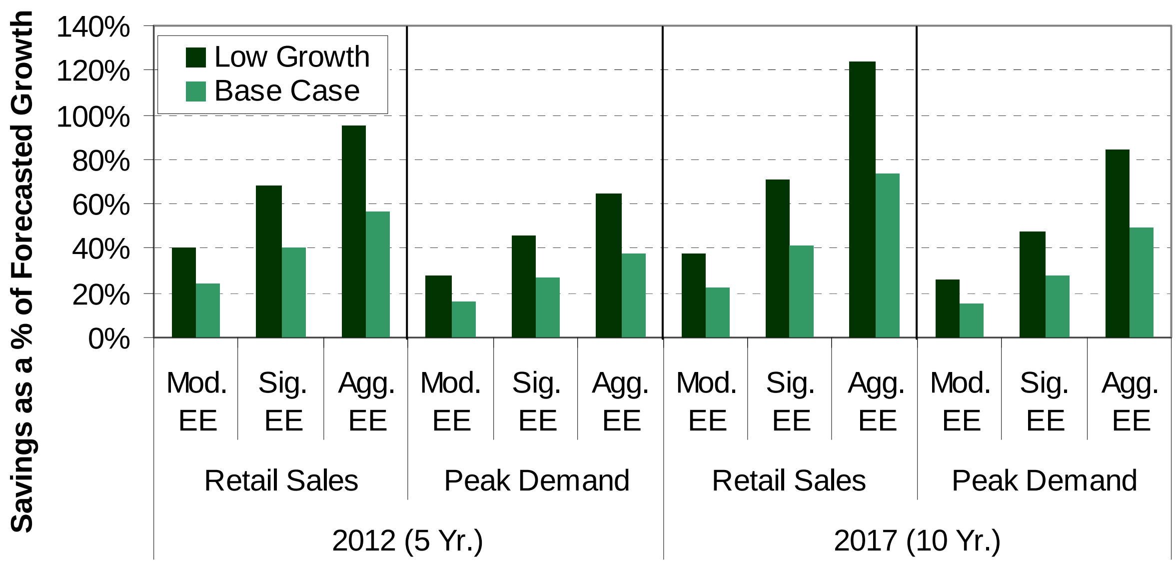

Figure E- 1. Growth in retail sales and peak demand offset by energy efficiency

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

[22] In all figures and tables in this appendix, the "Base Case" refers to the results summarized in section **Error! Reference source not found.**.

T&D infrastructure further into the future than is observed in the base case.[23] In the base case, 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).

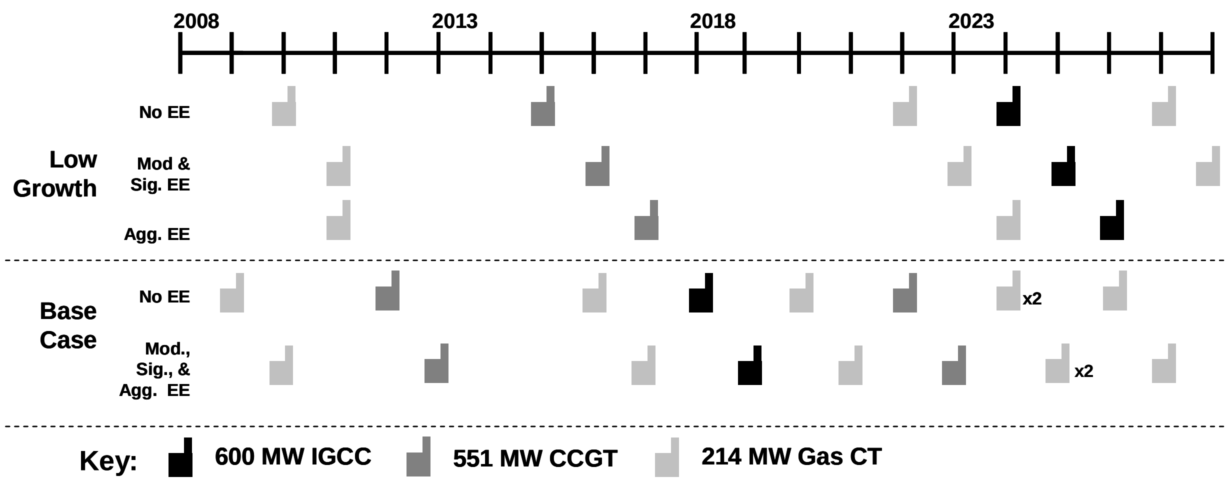

Figure E- 2. Timing of major generation plan additions for Low Growth utility

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.

[23] 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 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.

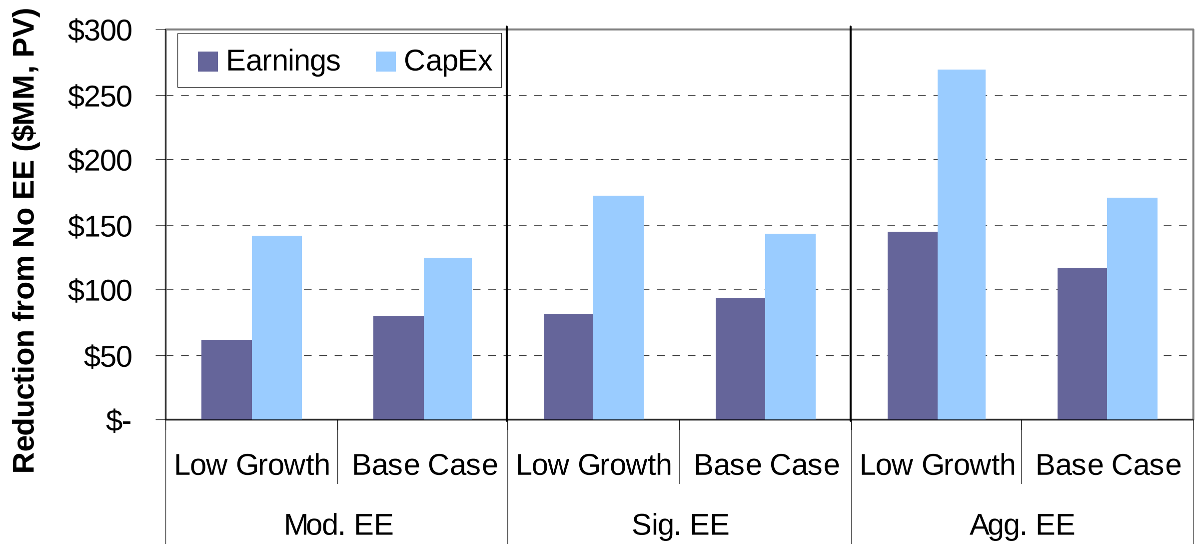

Figure E- 3. Reduction in earnings and CapEx for Low Growth utility

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.

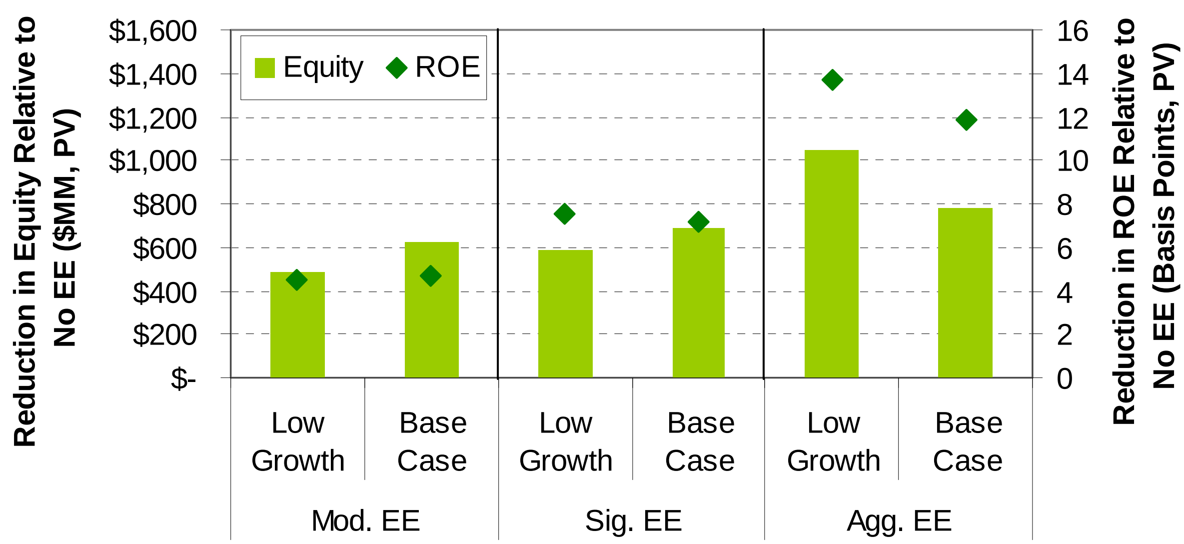

Figure E- 4. Reduction in equity and ROE for Low Growth utility

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).

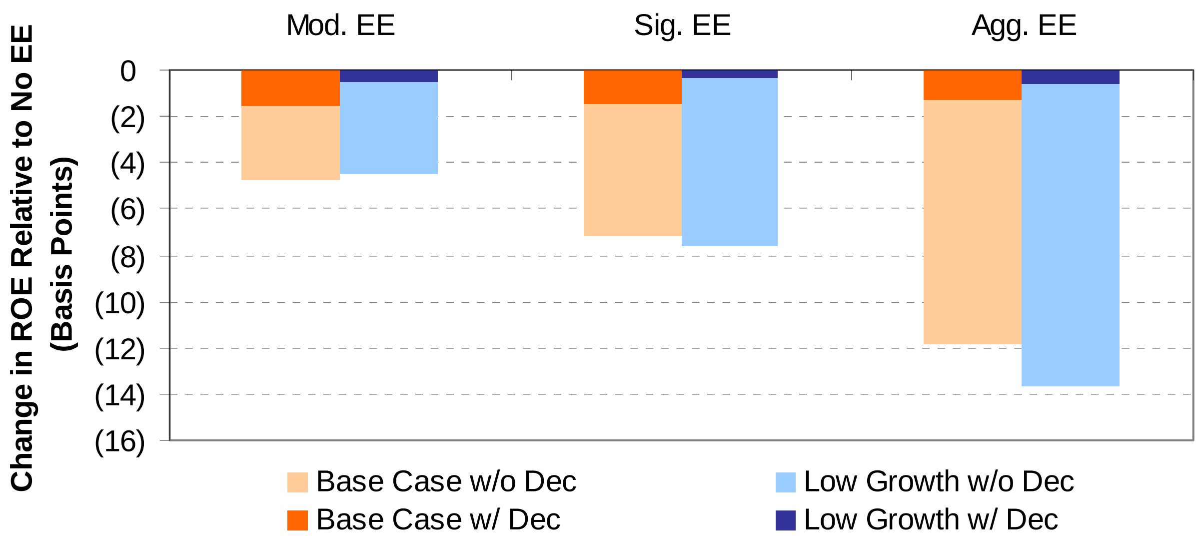

Figure E- 5. Effect of decoupling on change in ROE relative to No EE case

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.

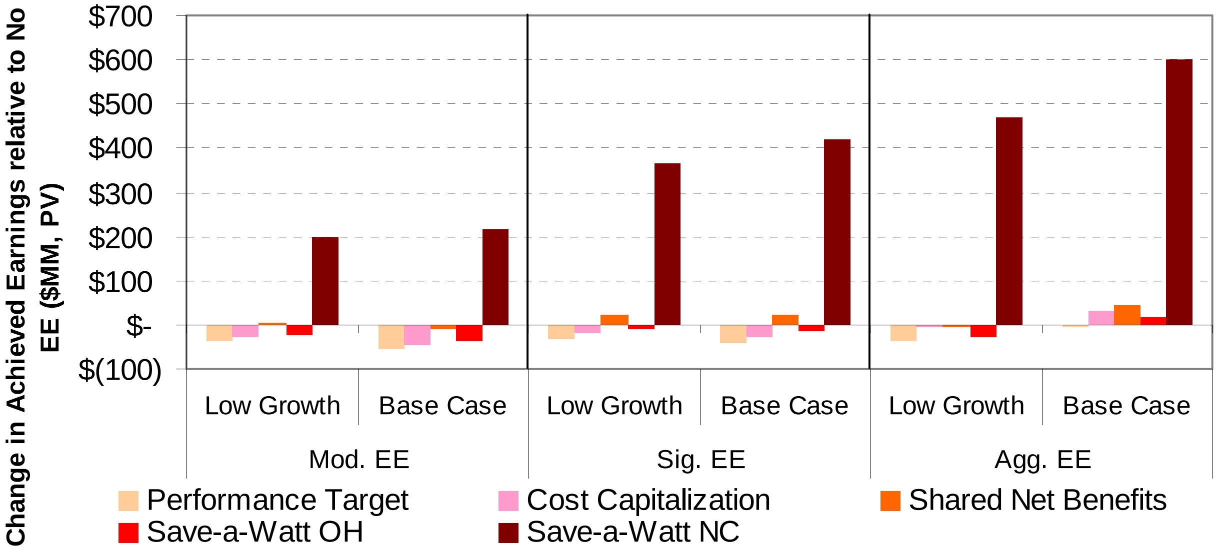

Figure E- 6. Effect of decoupling or shareholder incentives on achieved earnings for Low Growth utility

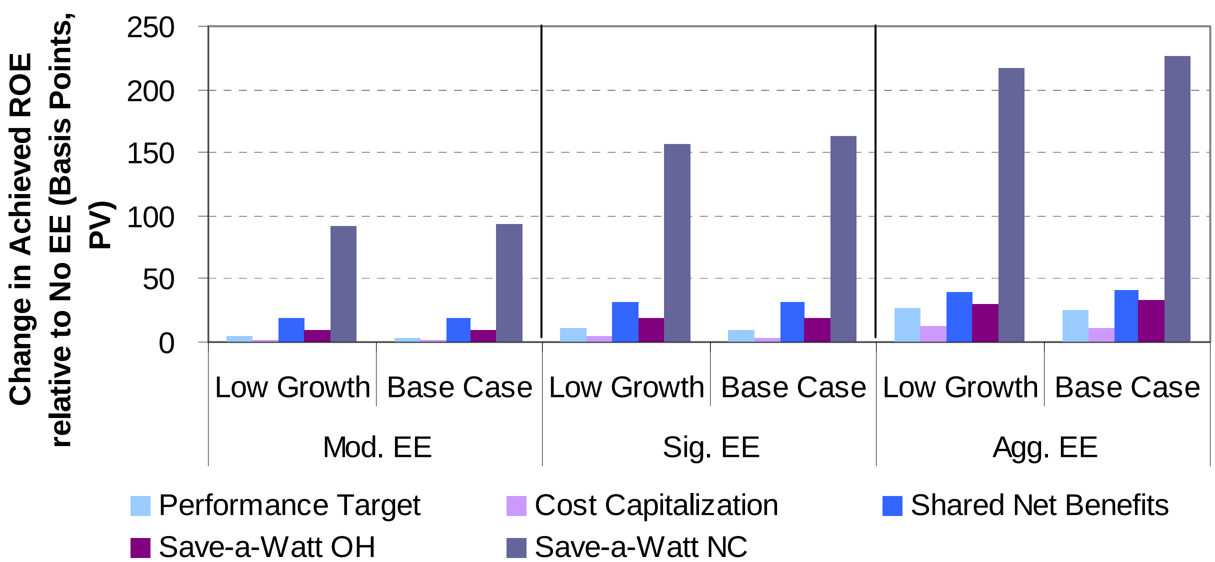

Figure E- 7. Effect of decoupling or shareholder incentives on achieved ROE for Low Growth utility

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.

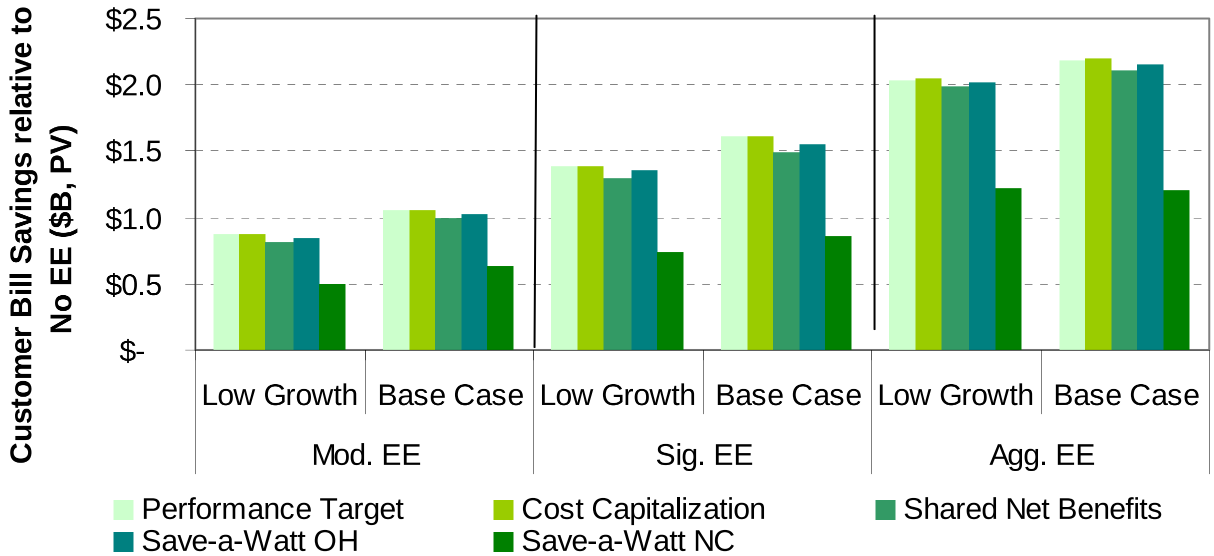

Figure E- 8. Effect of decoupling or shareholder incentives on customer bill savings for Low Growth utility

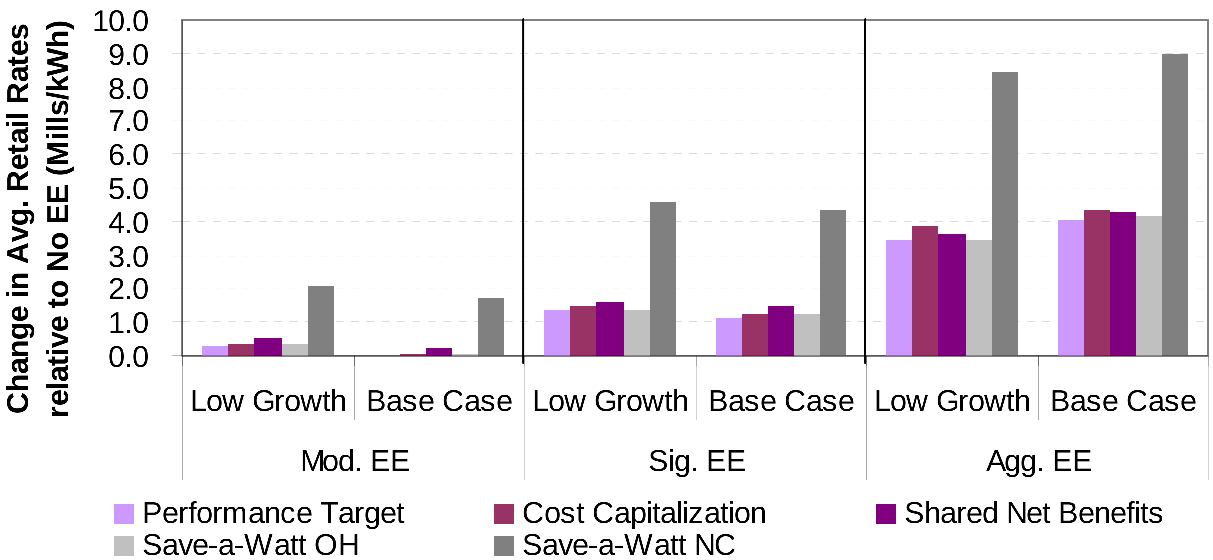

Figure E- 9. Effect of decoupling or shareholder incentives on average retail rates for Low Growth utility

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.[24] 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).[25] 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.

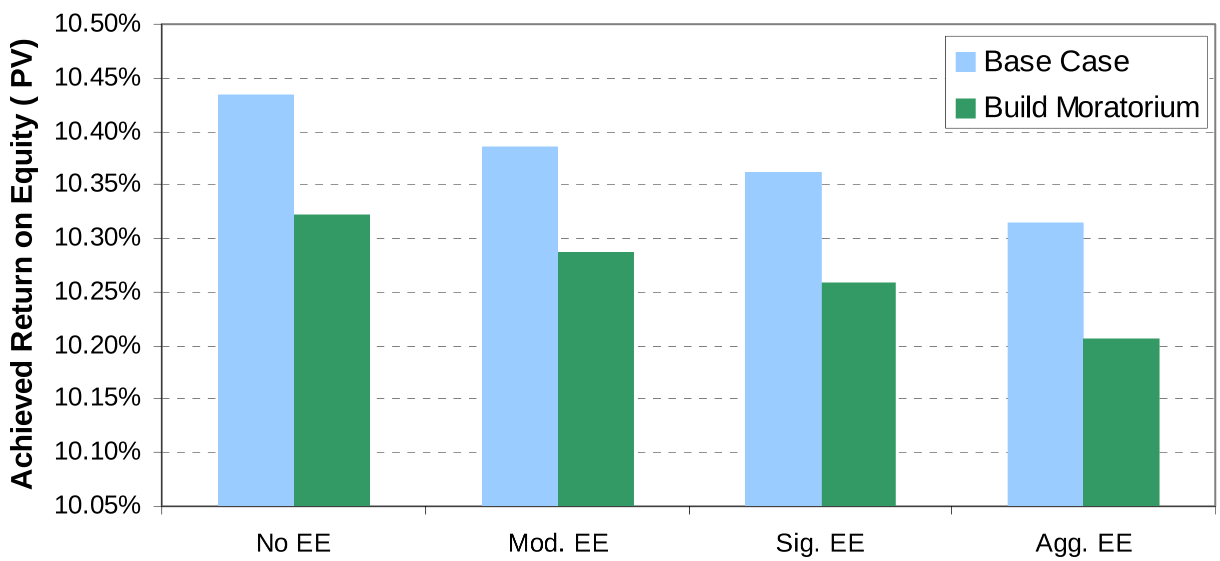

Figure E- 10. Effect of energy efficiency on achieved ROE for Utility Build Moratorium case

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

[24] 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).

[25] 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).

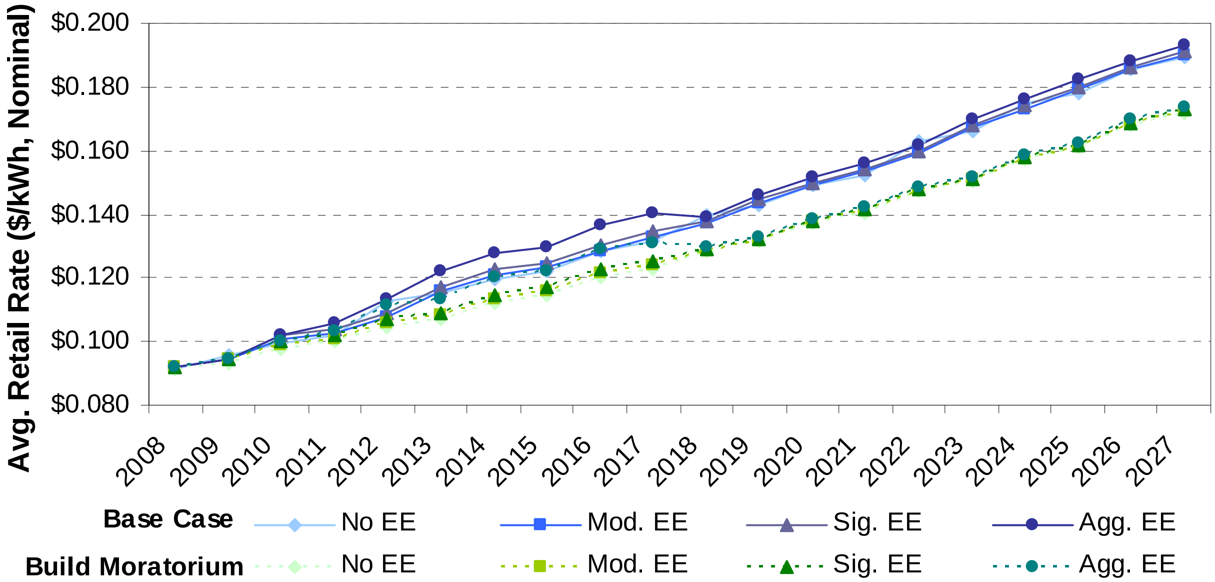

Figure E- 11. Base Case and Utility Build Moratorium annual average retail rates

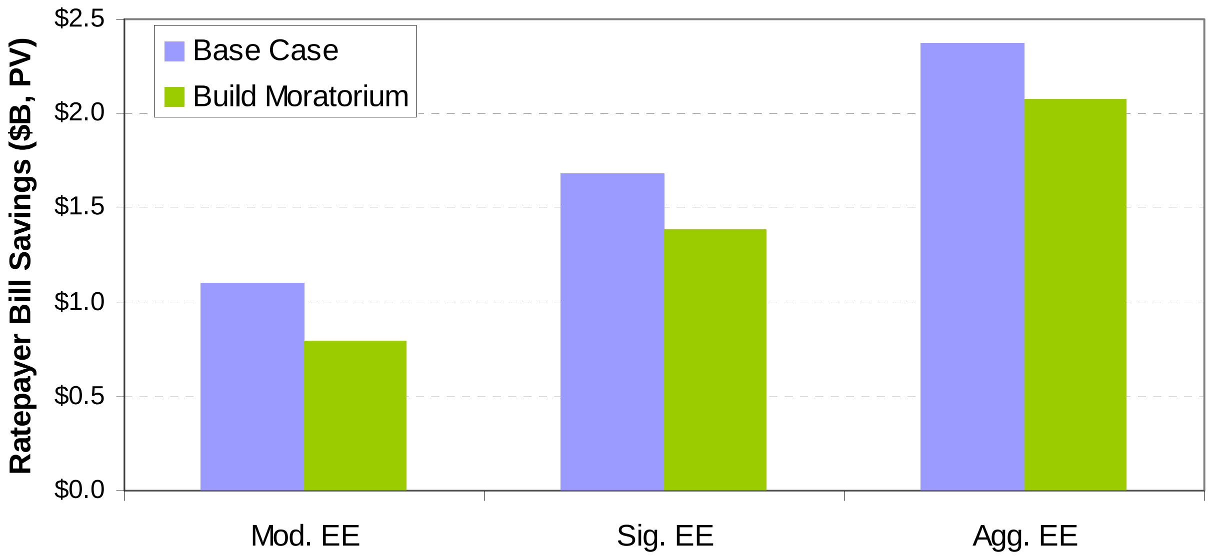

Figure E- 12. Effect of energy efficiency on ratepayer bill savings for Utility Build Moratorium case

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).

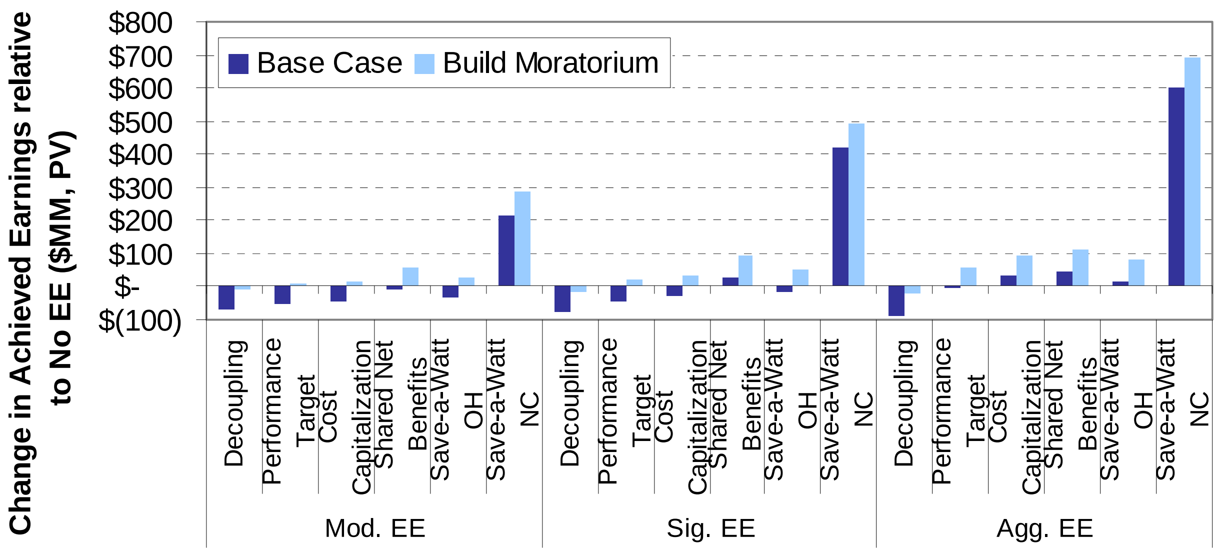

Figure E- 13. Effect of decoupling and shareholder incentives on achieved earnings for Utility Build Moratorium Case

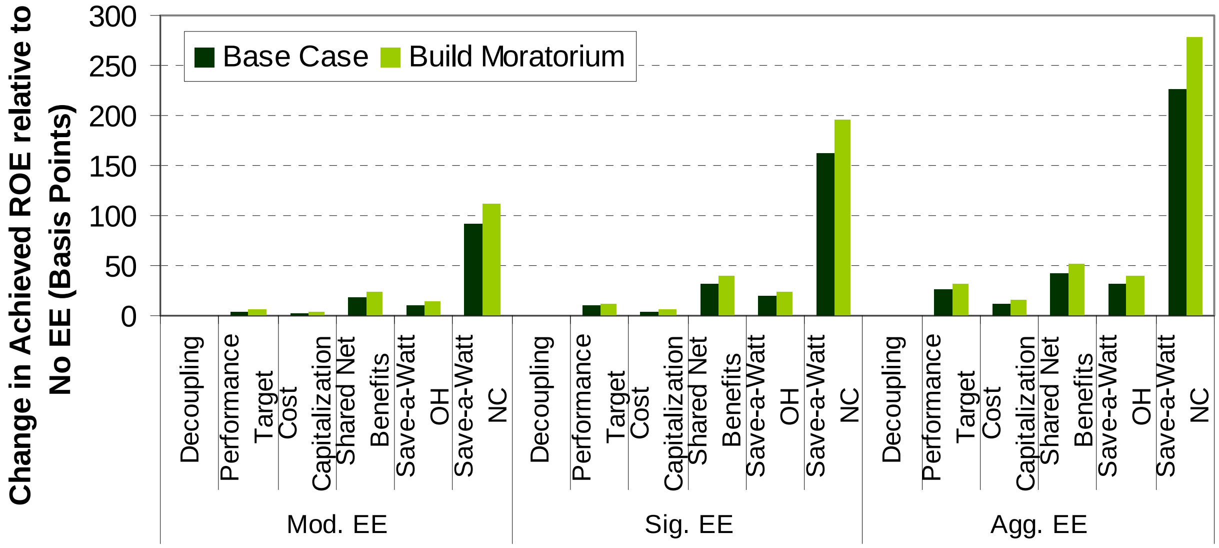

Figure E- 14. Effect of decoupling and shareholder incentives on achieved ROE for Utility Build Moratorium case

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.

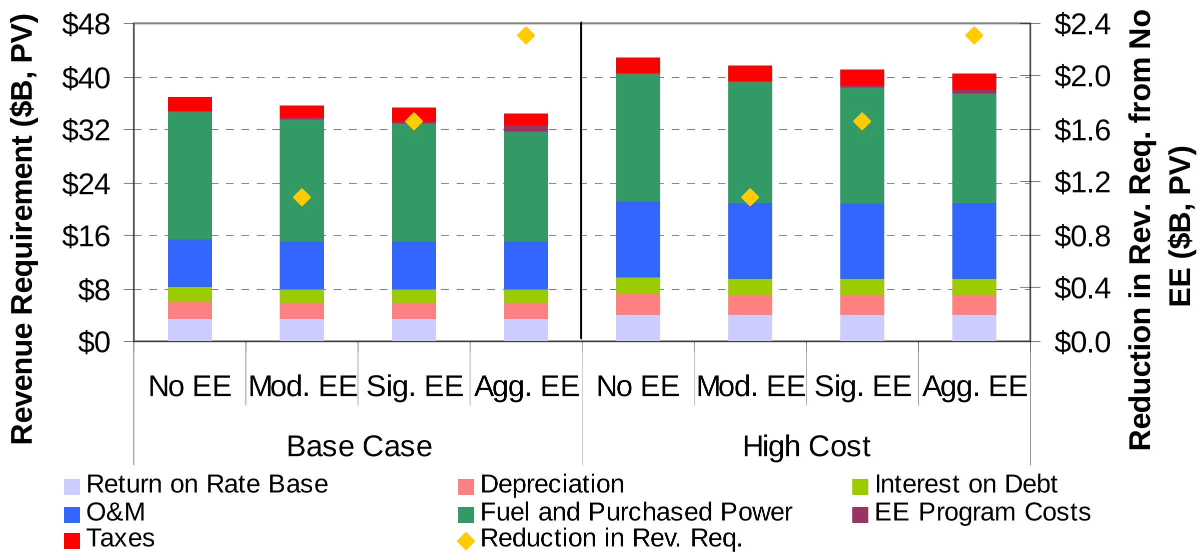

Figure E- 15. 20-Year revenue requirement for High Cost Utility sensitivity case

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.[26] 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).

[26] 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.

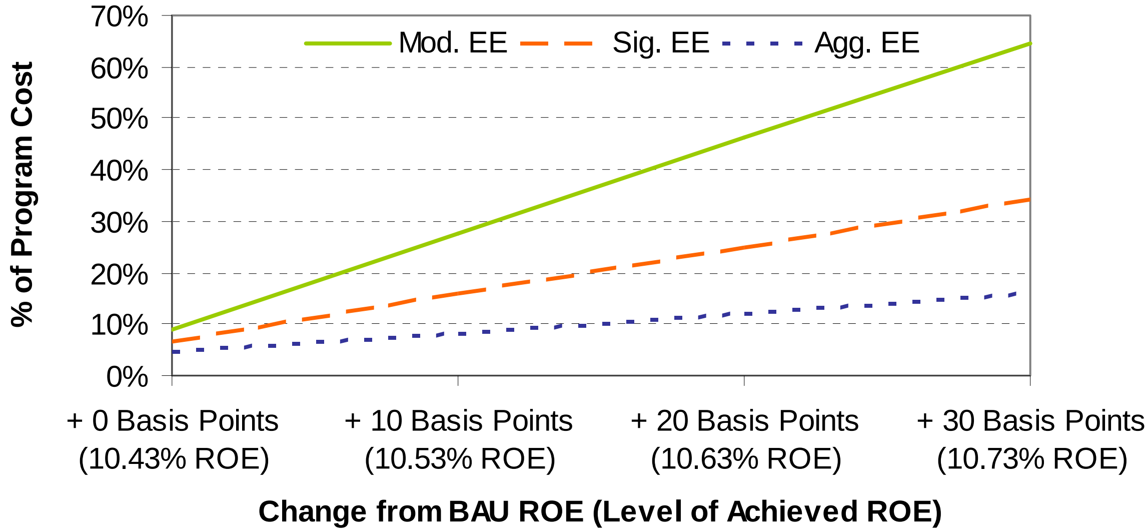

Figure F- 1. Relationship between Performance Target mechanism earnings basis and change in ROE

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).

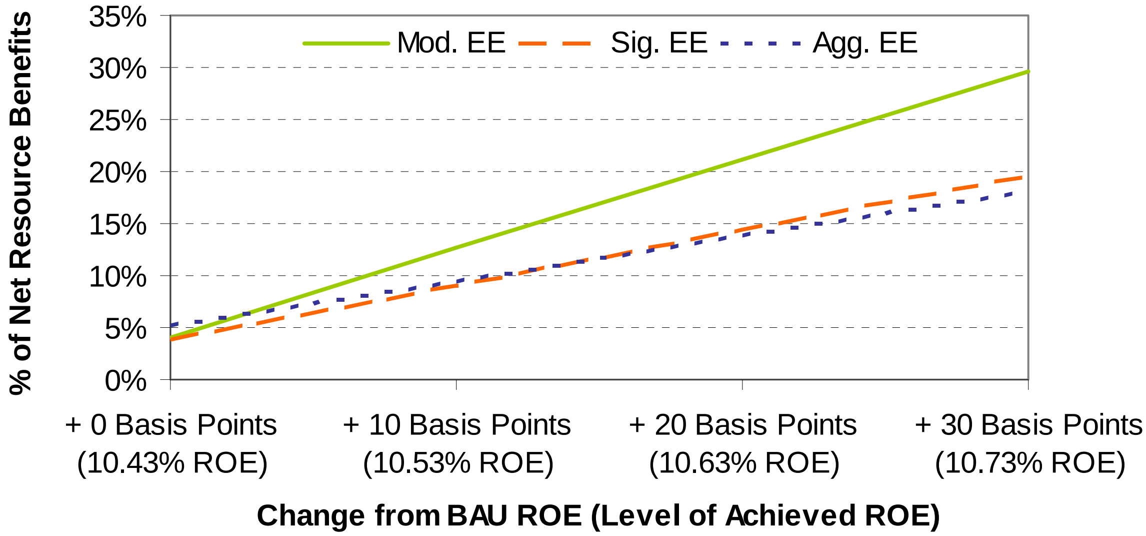

Figure F- 2. Relationship between Shared Net Benefits earnings basis and change in ROE

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.[27] 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.[28] 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).

[27] 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.

[28] 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.

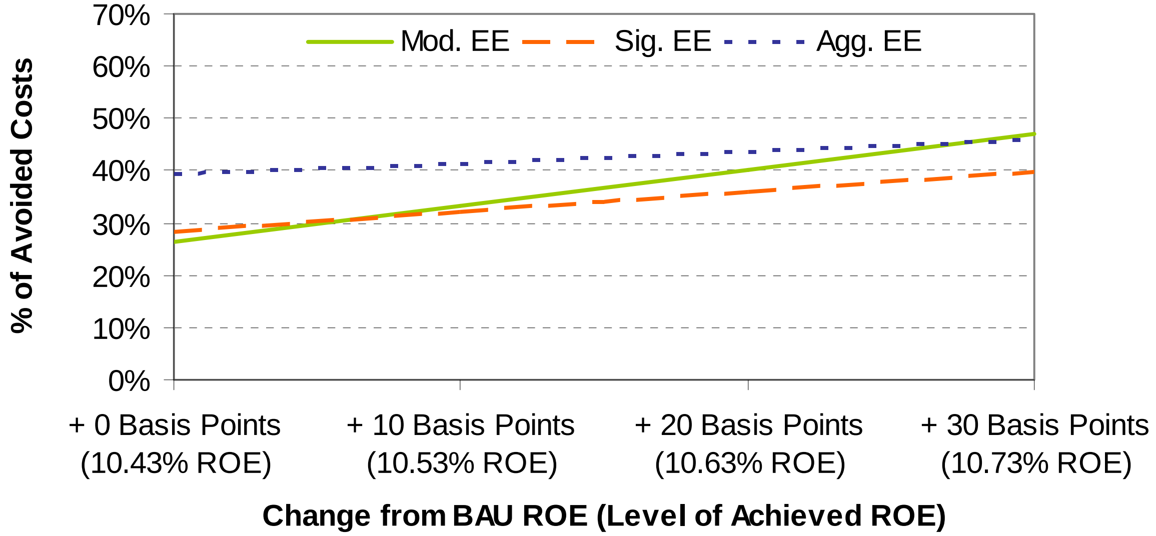

Figure F- 3. Relationship between Save-a-Watt NC earnings basis and change in ROE

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.

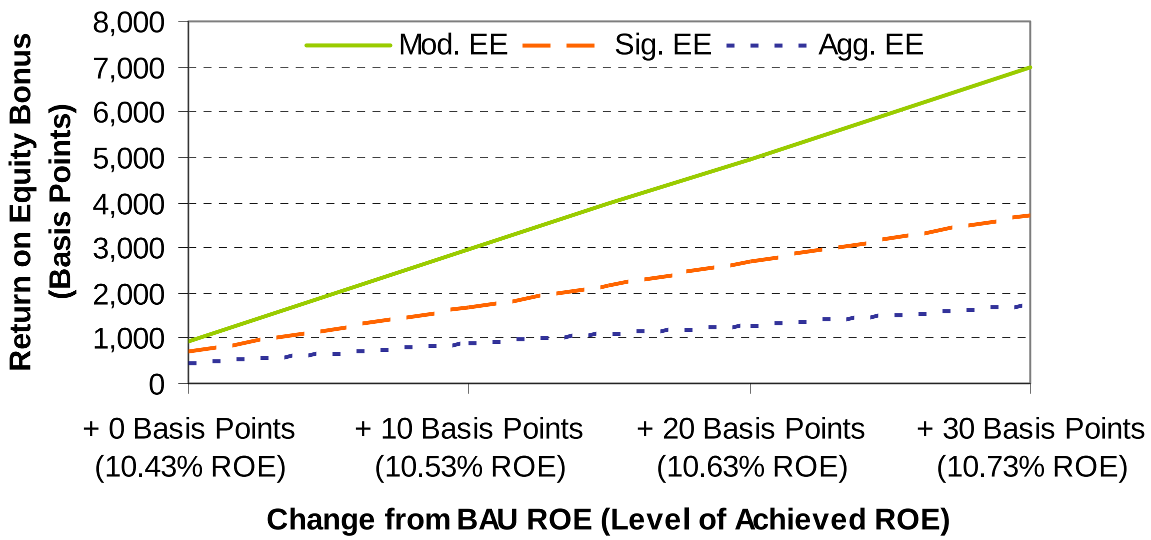

Figure F- 4. Relationship between Cost Capitalization earnings basis and change in ROE

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.[29]

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

[29] 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).

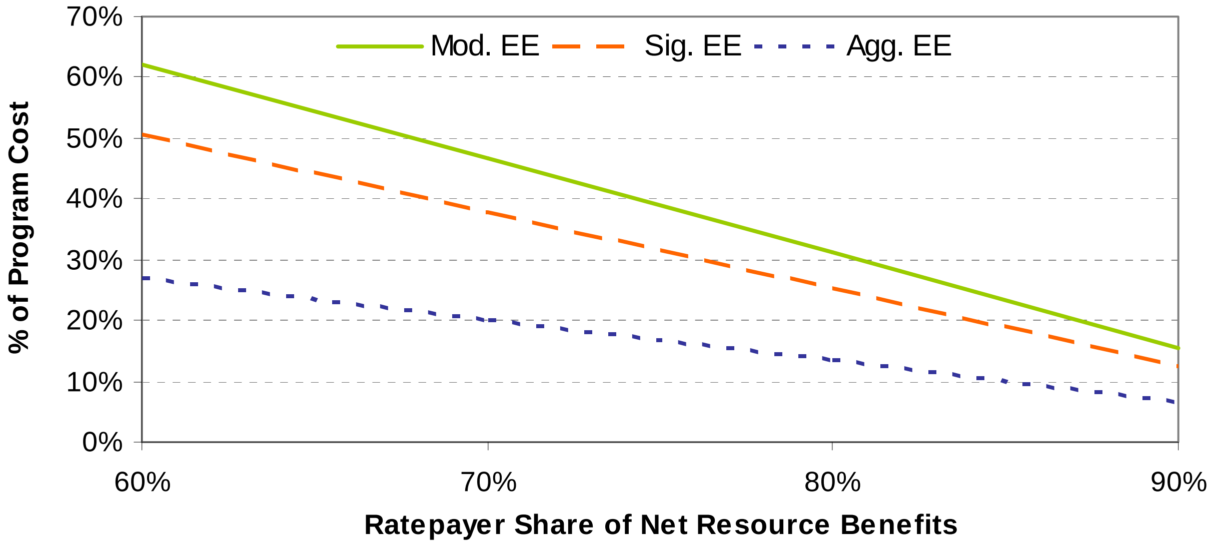

Figure F- 5. Relationship between Performance Target mechanism earnings basis and ratepayer share of net resource benefits

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.[30]

[30] 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%.

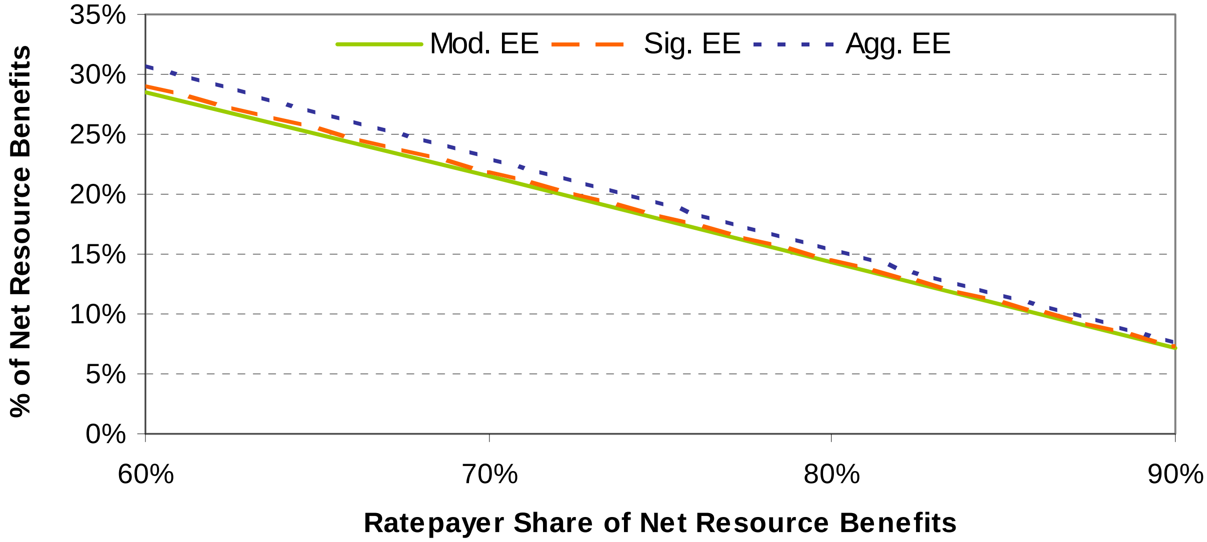

Figure F- 6. Relationship between Shared Net Benefits earnings basis and ratepayer share of net resource benefits

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).

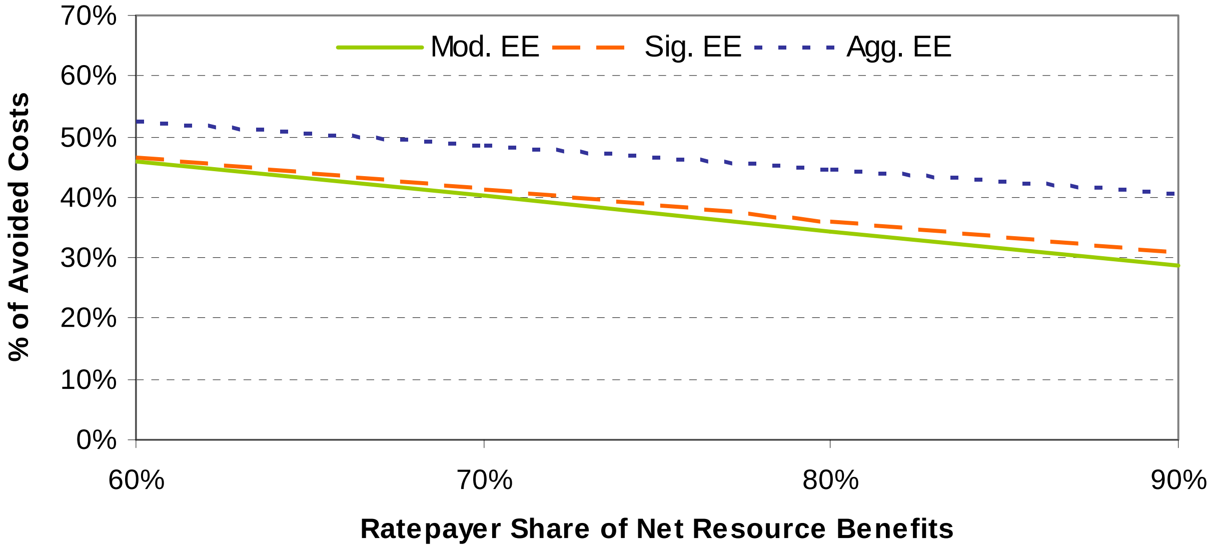

Figure F- 7. Relationship between Save-a-Watt NC earnings basis and and ratepayer share of net resource benefits

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.

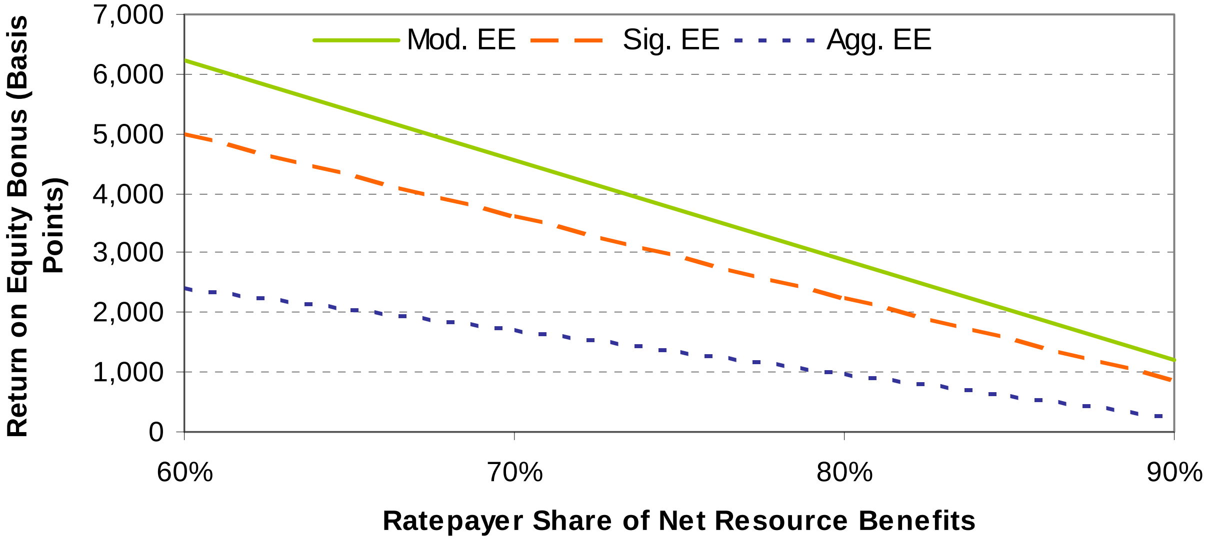

Figure F- 8. Relationship between Cost Capitalization earnings basis and and ratepayer share of net resource benefits

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.[31]

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.

[31] 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