Utility Energy Efficiency Regulatory Recovery Mechanisms: A Different Perspective

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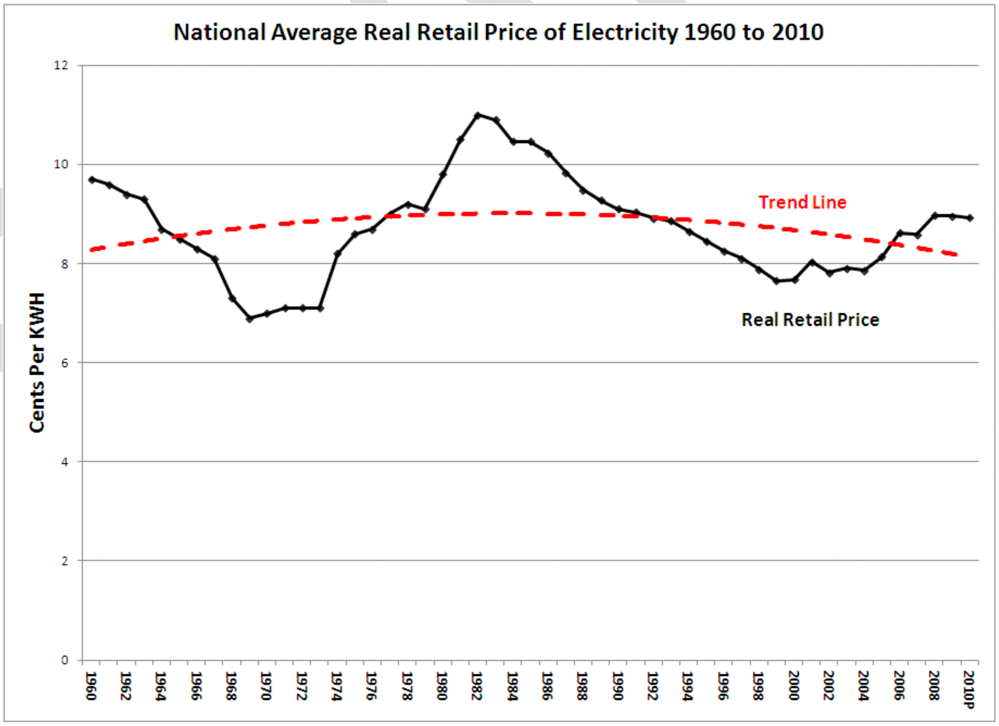
I. Introduction

As long as electric utilities have operated under a state/utility regulatory compact, they have possessed a mandate to provide their customers with safe, low-cost, reliable power in exchange for the opportunity to earn a fair rate of return on their investments (i.e., rate base). Under this regulatory model, utilities invest in generation and power delivery assets to meet customer demand, and investors require a return based on expectations of earnings growth through cost management and prudent investments in generating capability driven by increasing energy sales. This regulatory construct has worked well over the long run to serve growing customer demand while the price of electricity has declined or remained relatively constant on an inflation-adjusted basis.[1] As shown by Figure 1, while the average retail price of electricity in real terms has fluctuated in a narrow band over the last 50 years, overall it has trended down, especially since 1982.

Figure 1



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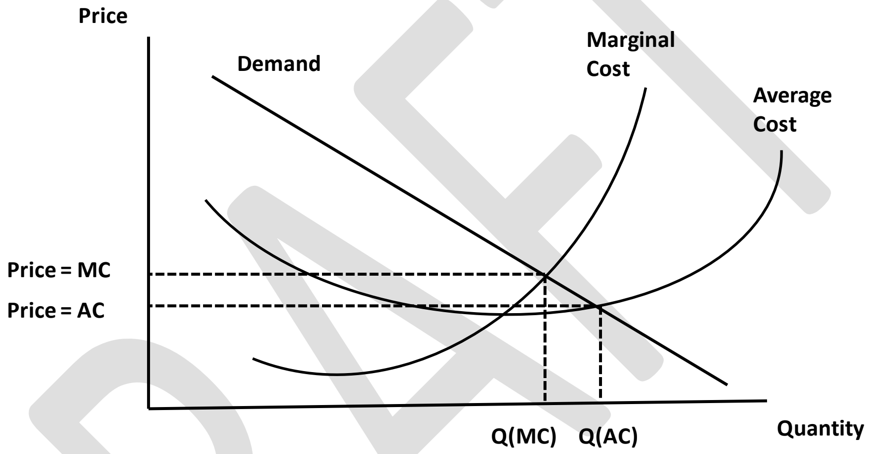
[1] Source is the Energy Information Administration, Table 8.10: Average Retail Prices of Electricity, 1960-2010.

However, one commonly recognized flaw in this regulatory construct is that electric prices are set artificially low at the utility's average embedded cost.[2] This flaw in pricing is a result of the cost-based, retrospective nature of regulation as well as a desire to provide low electricity rates that encourage economic growth and promote social welfare. As a result, electric utility customers tend to over-consume because they do not face prices that reflect the utility's current marginal cost of production. This conundrum prevents customers from adequately evaluating the economic trade-off between additional electricity consumption (along with the associated asset investments to serve that consumption) and the cost of investing in energy efficiency and demand-side management (EE).[3] This effect is illustrated in Figure 2.

Figure 2 – Consumption of Electricity at Embedded and Marginal Cost



When utilities charge electricity prices set below their marginal costs, customers historically have demanded more electricity than what is considered economically efficient (e.g. the quantity that would be supplied if prices were set at marginal cost). At the same time, utilities are charged by regulators to provide reliable and affordable service, necessitating long-term planning and investment in assets to meet elevated customer demand. This disconnection between the pricing of electricity and marginal costs set the stage for the introduction of EE programs to encourage customers to reduce their consumption back to an economically-efficient level. Integrated Resource Planning (IRP) was developed by utilities in the 1970's and 1980's to incorporate EE programs in generation planning to economically reduce expected future loads.

Generally speaking, EE programs were considered cost-effective by a utility if the cost to implement those programs was less than the utility's avoided cost of production plus the cost of new capacity for generation, transmission, and distribution equipment (see Figure 3). Ideally, a utility that implements all cost-effective EE programs should be able to reduce customer demand to a level of energy use equivalent to what customers would consume if prices were set at marginal cost.

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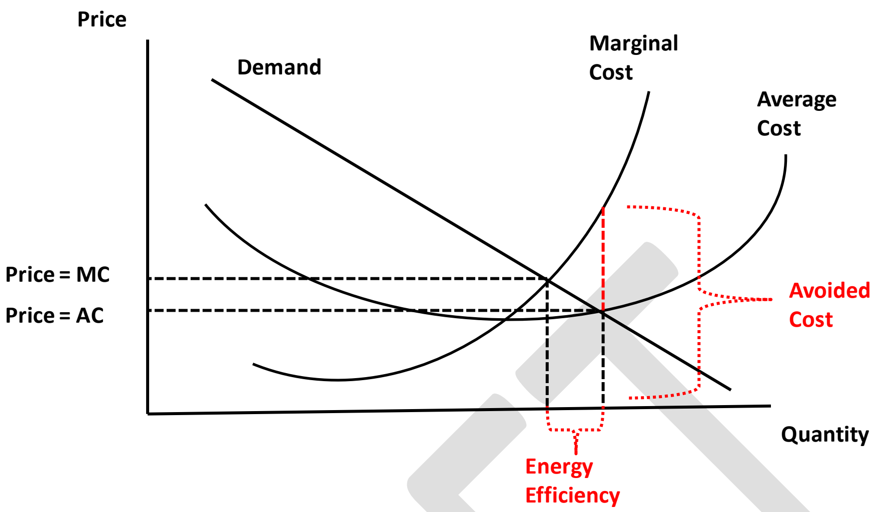
[2] Some states established fair value as the base for establishing a rate base, but this did not prevent a commission from setting a rate of return as if the rate base was established using embedded costs.

[3] Definitions of EE and DSM vary across jurisdictions and other governmental agencies. For simplicity, this paper assumes that EE also includes energy efficiency and demand response or demand-side management programs.

Figure 3 – Consumption Reduction After Implementation of Energy Efficiency



While this relationship is not new, it can be examined from a different perspective by exploring the relationship between asset-based utility earnings and EE which appears to reduce utility earnings. This is an important comparison because assets and EE programs must compete internally for company resources, but they produce very different financial results. Utility management and regulators must therefore consider the earnings relationship between these two different resources whenever making investment decisions. Given that a utility must plan and invest in assets to serve customer demand, reducing consumption through EE creates short-term earnings pressure since existing utility assets and their costs do not disappear when demand is reduced[4]. This argues for the existence of a regulatory mechanism to bridge the financial divide from a system based on average embedded cost pricing with elevated demand to a system based on marginal cost that is closer to being economically "right-sized" or efficient. Similarly, any EE regulatory mechanism that fails to provide comparable earnings to an asset will naturally bias utility management to favor investments in assets over EE no matter how cost-effective the programs may be. Since regulatory policy seems to favor encouraging EE programs while setting electric rates below the marginal cost of production, utilities will be forced to manage under contradictory objectives (e.g. satisfying artificially-high demand while pursuing programs that undermine demand).

These contradictory objectives raise the following questions:

- Given that a utility must invest in assets to meet customer demand (regardless of whether the demand is economically-efficient or not), how should utilities be compensated for EE programs that reduce consumer demand for electricity?
- Should utilities be allowed to recover the cost of existing investments (e.g. lost margins)?
- Can a utility be financially successful over the long run by reducing customer demand to an economically-efficient level?

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[4] Myron B. Katz, "Demand-side Management Reflections of an Irreverent Regulator," Resources and Energy 14 (1992), p. 192.

Answers to these questions can be obtained through the construction of a theoretical model to examine the different financial outcomes of a utility that pursues EE versus a utility that builds supply-side assets to satisfy customer demand. This paper uses this model to examine the financial implications of standard EE regulatory recovery models in order to demonstrate their financial benefits and drawbacks. Additionally, this paper examines the short- and long-term financial impacts on utilities from regulatory mandates to achieve certain levels of energy efficiency (e.g., energy efficiency resource standards) in lieu of traditional investments in new supply-side resources.

In the following section, we develop the theoretical model to examine the motivations of an electric utility under the traditional regulatory asset-focused model with and without implementation of EE programs. We then examine the theoretical conditions to compare one EE regulatory recovery mechanism with another. In addition, we investigate the need for recovery of lost margins and assess the long-term implications of the contradictory objectives confronting utilities.

II. Utility Compensation for Reducing Consumer Demand for Electricity

EE programs can function as assets in that they produce results (e.g. energy and capacity reductions) for customers over many years. However, a key consideration to making the utility financially indifferent between an investment in an asset and an investment in EE is the equivalency of earnings between the two investment choices. Thus, a common question posed when implementing EE programs is to determine what level of earnings from an EE regulatory mechanism are needed to earn an equivalent cash return from an investment in an asset. In the following paragraphs, we proceed through several variations of a theoretical financial model to determine the impact on utility earnings under alternate regulatory recovery mechanisms for EE programs. The objective in this section is to understand the conditions which make earnings equivalent between an asset and a similar EE program.

Traditional Regulatory Model for Utility Investments in Generating Plant and Equipment

Under the traditional regulatory model, as customer demand rises electric utilities invest in the construction of new generating plant and equipment. The choice of the type of generating plant to be built is driven through an examination of tradeoffs between cost and reliability plus availability. In this way, utilities meet regulatory requirements to provide electric service at the lowest reasonable cost. We have used the word “reasonable” here to reflect that the lowest cost resource isn’t always the ideal asset to build. Instead, other considerations, such as reliability and availability of the generating equipment, must also be included in the construction decisions in order to choose the optimal solution.

Once a plant is constructed and recovery of costs (which includes a reasonable return) is sought from the regulatory authorities through a utility’s application to increase customer rates, a utility’s revenue requirements are established. In its basic form, the revenue requirements set through a rate-making proceeding may be characterized mathematically as follows:

(1) $RR = P \cdot Q = VC \cdot Q + FC + r \cdot RB + T + D$

where:

RR = revenue requirements set by the regulatory authority in time period t;
P = electricity rate;
Q = quantity of kWh sales

VC = unit variable costs (assumed constant);
FC = fixed costs;
r = rate of return;
RB = rate base;
T = tax expense;
D = depreciation

This structure helps us understand the key drivers of revenue requirements (fixed and variable costs, return on rate base, taxes, depreciation) and earnings (kWh sales and the level of rate base) for the utility. Keep in mind that changes in RB are driven ultimately by projected changes in Q over the long-run. However, in the short-run, the ability of the utility to increase net income (earnings after interest and taxes) is by increasing sales and/or reducing fixed costs.

$$(2)\quad NI = P \cdot Q - VC \cdot Q - FC - T - D - I$$

where:

NI = net income (after interest and taxes)
I = interest expense

Taking a total differential of (2) produces:

$$(3)\quad \Delta NI = P \cdot \Delta Q + Q \cdot \Delta P - VC \cdot \Delta Q - Q \cdot \Delta VC - \Delta FC - \Delta T - \Delta D - \Delta I$$

Assuming no price changes, relatively constant unit costs, and no change in taxes, then we can set $\Delta P = 0$; $\Delta VC = 0$; $\Delta D = 0$, $\Delta I = 0$, and $\Delta T = 0$. This reduces ΔNI to:

$$(4)\quad \begin{aligned} \Delta NI &= P \cdot \Delta Q - VC \cdot \Delta Q - \Delta FC \\ &= (P - VC) \cdot \Delta Q - \Delta FC \end{aligned}$$

Thus, *NI* can increase if $P > VC$ and *Q* increases and/ or *FC* is reduced.

Alternatively, if *NI* is defined using the components of *RR*, it produces:

$$(5)\quad NI = w \cdot roe \cdot RB(Q)$$

where:

w = equity percentage of the capital structure;
roe = equity rate of return over the lifetime of the asset

This is for a given level of *Q* which implies that increases in rate base are necessary to raise *NI*. These relatively simple constructs can be used as the basis for assessing alternate regulatory recovery mechanisms as well as regulatory financial decision criteria.

An Analysis of Regulatory Models for Utility Investments in Energy Efficiency

When it comes to providing utilities with a financial bridge to cover the transition from a system designed to serve an elevated level of consumer demand to an economically-efficient designed system, there are three primary types of incentive-based EE regulatory mechanisms that have been employed.[5] These regulatory models include: shared savings, percent of program costs, and percent of avoided costs.[6]

Under the **shared savings** approach, the utility's financial incentive is based upon a percent of the difference between the present value of the avoided costs associated with the implementation of an EE program and the present value of the EE program's costs. This can be represented as:

$$(6)\quad SS = s \cdot (AC - PC) \cdot Q(EE)$$

where,

SS = shared savings incentive
s = shared savings percentage
AC = PV (avoided costs) per unit of EE
PC = PV (EE program costs) per unit of EE
Q(EE) = amount of achievable energy efficiency or demand-side management

Q(EE) represents the difference between Q(AC) and Q(MC) on Figure 2.

The relationship between shared savings and avoided costs is depicted in Figure 4. If the utility achieves a net savings (avoided costs net of program costs) of $5,000,000, a 10% shared savings percentage, *s,* produces a $500,000 incentive. It should be noted the amount of the incentive depends upon the UCT of the program or portfolio of programs (a reflection of the cost-effectiveness) and the shared savings percentage.

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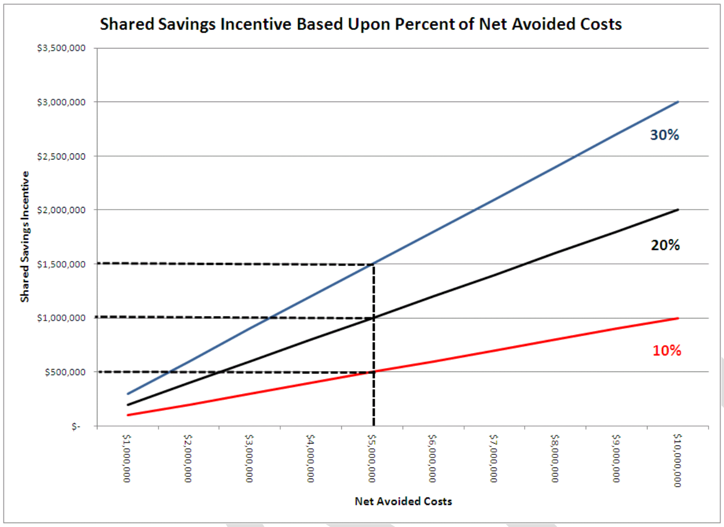
[5] See Sara Hayes, et. al., Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency, (Washington D.C.: American Council for an Energy Efficient Economy, 2011) Table 1, p 12; Steven Stoft and Richard J. Gilbert, "A Review and Analysis of Electric Utility Conservation Incentives," The Yale Journal on Regulation, 11(1, 1994), p.4; and Peter Cappers, et.al., Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility, (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, March, 2009).

[6] Percent of avoided costs was first proposed by Duke Energy in its save-a-watt energy efficiency application before the North Carolina Utilities Commission in 2007 and approved in a modified form by that Commission on February 9, 2010 in Docket No. E-7, Sub 831. Additionally, save-a-watt was approved by the Public Utilities Commission of Ohio in Case No. 08-920-EL-SSO and the Public Service Commission of South Carolina in Docket No. 2009-226-E.

Figure 4 – Shared Savings vs. Net Avoided Costs



The **percent of program cost** regulatory mechanism provides the utility with a financial incentive based on a set percentage of EE program costs. This can be expressed as:

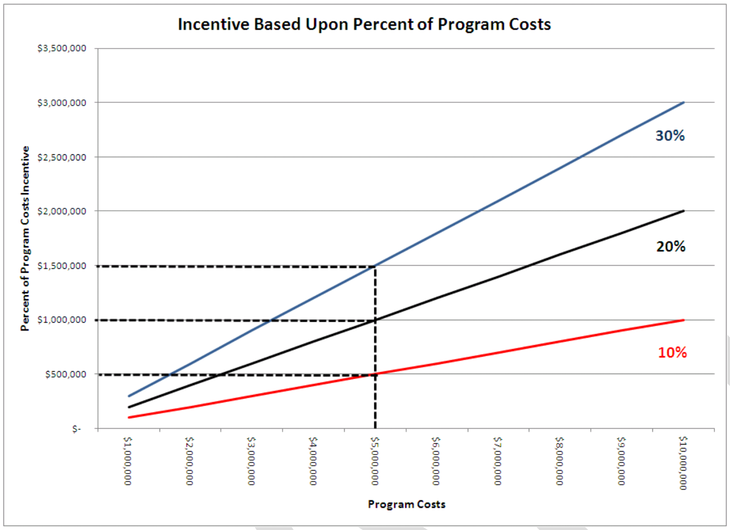
(7) $PPC = p \cdot (PC) \cdot Q(EE)$

where,

PPC = incentive based on percent of program costs
p = percentage incentive
PC = PV (EE program costs) per unit of EE

The relationship between program costs and an incentive based on percent program costs is depicted in Figure 5. Under this model, program costs of $5,000,000 with a 10% percent incentive, *p*, of program costs produces a $500,000 benefit. Unlike shared savings or an avoided cost model, an incentive based on program cost is not dependent on the level of the UCT score. However, it is presumed that EE programs being implemented under this model are cost-effective.

Figure 5 – Incentive from Percent of Program Costs vs. Program Costs



Lastly, the **percent of avoided cost** regulatory mechanism is different (and riskier for the utility) from the previous two mechanisms because there is no explicit recovery of EE program costs. Under this approach, revenues are computed as a percent of the present value of the avoided costs. However, the revenues are then reduced by the program costs in arriving at any incentive. As a result, explicit recovery of program costs is a potential risk to the utility. This mechanism can be expressed as:

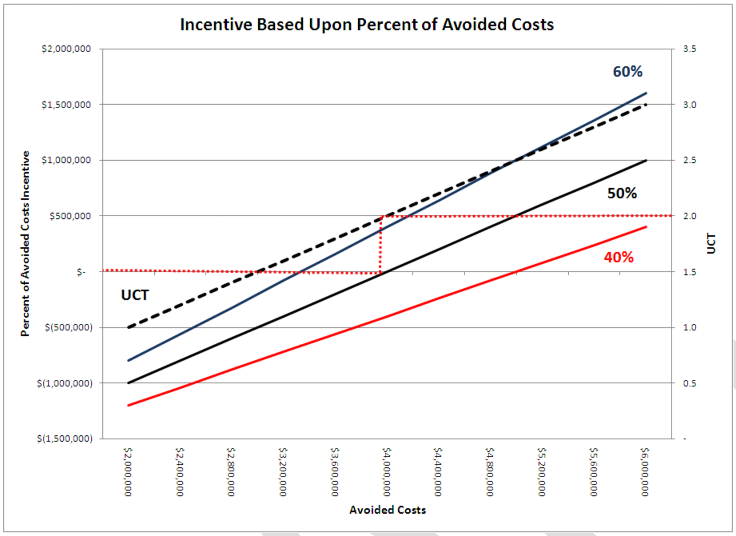
(8) $PAC = (z \cdot AC - PC) \cdot Q(EE)$

where,

PAC = incentive based on percent of avoided costs
z = percentage applied to the avoided costs
AC = PV (avoided costs) per unit of EE
PC = PV (EE program costs) per unit of EE

The relationship between avoided costs and an incentive based on percent avoided costs is depicted in Figure 6. The dashed line shows the UCT score based on a given program cost. The solid lines show the level of earnings that come from a given avoided cost percentage, *z*. Similar to the shared savings model, UCT factors strongly into determining the level of incentive that may be earned by the utility under this model. For example, for a 2.0 UCT score and $4,000,000 in avoided costs, a 50% avoided costs level produces a potential break-even position for the utility. 50% of $4,000,000 would just equal the program costs of this EE program with a UCT of 2.0. Also important to note are the negative incentive values that occur as the UCT score declines at a given *z*.

Figure 6 – Incentive from Percent of Avoided Costs vs. Avoided Costs



While each of the methods may include recovery of lost margins, discussion of the issue of lost margins due to reductions in utility sales has been deferred to Section III.

Adding these definitions to the definition of *NI* net of lost margins in equation (2) yields the following:

(9) $NI(SS) = (P - VC) \cdot Q - FC - T - D - I + s \cdot (AC - PC) \cdot Q(EE)$
(10) $NI(PPC) = (P - VC) \cdot Q - FC - T - D - I + p \cdot (PC) \cdot Q(EE)$
(11) $NI(PAC) = (P - VC) \cdot Q - FC - T - D - I + (z \cdot AC - PC) \cdot Q(EE)$

Based upon these equations, the conditions that would equalize the incentive to the utility across the separate mechanisms are the following:

$$\begin{array}{llllll} & \underline{SS} & = & \underline{PPC} & = & \underline{PAC} \\ (12) & s & = & p/(UCT - 1) & = & (z \cdot UCT - 1)/(UCT - 1) \end{array}$$

where,

UCT = utility cost test or (AC / PC)

Alternatively, in terms of s, $p = s \cdot (UCT - 1)$ and $z = s + ((1 - s) / UCT)$. Figures 7, 8, and 9 provide graphical views of the relationships among these recovery mechanisms. For example, Figure 7 points out how the percent of program costs would have to change at different UCT levels if the shared savings percentage was 20%. Similarly, Figure 8 demonstrates how the percent of avoided costs would have to change at different UCT levels if the shared savings percentage was 20%. And, Figure 9 shows how the percent of avoided costs would have to change at different UCT levels if the percent of program costs was 20%.

Figure 7 – Percent Shared Savings & Percent Program Costs

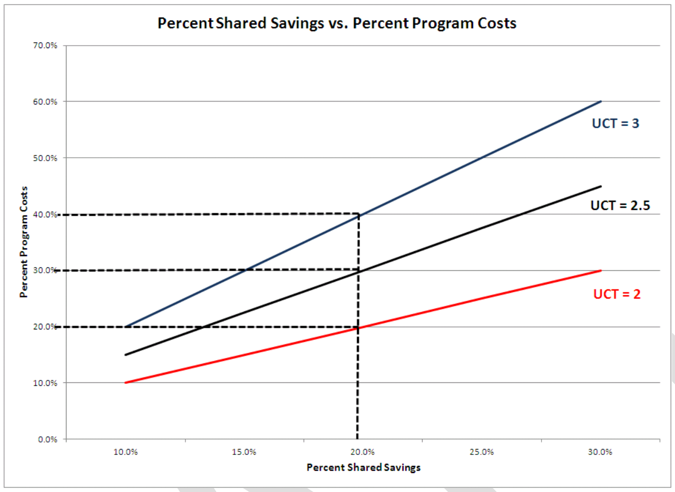


Figure 8 – Percent Shared Savings & Percent Avoided Costs

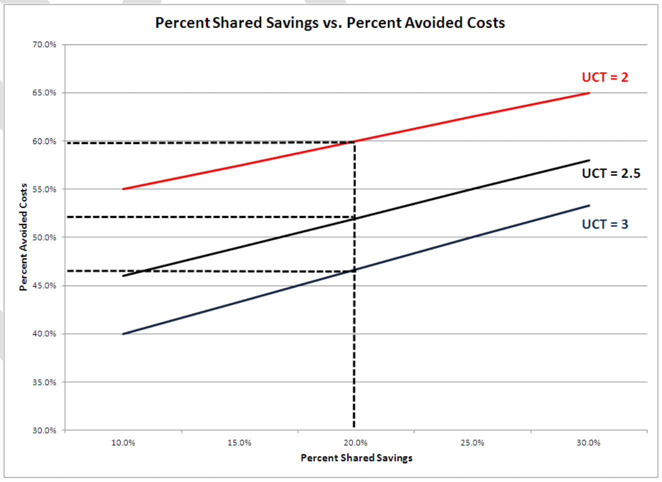
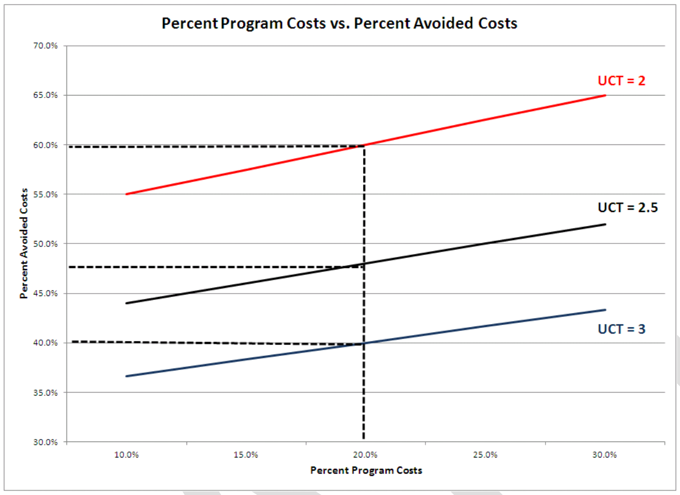


Figure 9 – Percent Program Costs & Percent Avoided Costs



Equation (12) provides the relationship that equalizes the utility earnings incentive across the regulatory recovery mechanisms. It should be recognized, though, that earnings under the PAC method have higher risk due to the fact that recovery of EE program cost remains at risk.[7] Also, as the UCT for the portfolio of the programs increases (decreases), the level of *s* needed to match the earnings achievable under a given *p* or *z* level decreases (increases).

Figures 10 and 11 provide examples of the percentages required for s, p, and z that will equalize earnings for two levels of the portfolio UCT (e.g., UCT = 2 and UCT = 3). These cases assume an EE program delivering 1,000,000 kWh in load reduction for 20 years and a discount rate of 7.0% after tax.

Figure 10 - Examples of Each Energy Efficiency Regulatory Model with UCT = 2

	Shared	% of Program	% of Avoided	
($)	$0.0793	$0.0793	$0.0793	Unit NPV of Avoided Costs AC
($)	$0.0397	$0.0397	$0.0397	Unit NPV of EE Program Costs PC
(#)	**2.00**	**2.00**	**2.00**	Utility Cost Test UCT
(%)	**10%**	N/A	N/A	Shared Savings %: s (Eq. 12)
(%)	N/A	**10%**	N/A	Program Cost %: p (Eq. 12)
(%)	N/A	N/A	**55%**	Avoided Cost %: z (Eq. 12)
($)	$42,181	$42,181	$42,181	Earnings from Each Energy Efficiency Regulatory Model

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[7] Due to the higher risk inherent in PAC, an argument can be made that the utility should earn a higher return under this model than what is typically allowed.

Figure 11 - Examples of Each Energy Efficiency Regulatory Model with UCT = 3

	Shared	% of Program	% of Avoided	
($)	$0.0960	$0.0960	$0.0960	Unit NPV of Avoided Costs AC
($)	$0.0320	$0.0320	$0.0320	Unit NPV of EE Program Costs PC
(#)	**3.00**	**3.00**	**3.00**	Utility Cost Test UCT
(%)	**10%**	N/A	N/A	Shared Savings %: s (Eq. 12)
(%)	N/A	**20%**	N/A	Program Cost %: p (Eq. 12)
(%)	N/A	N/A	**40%**	Avoided Cost %: z (Eq. 12)
($)	$68,077	$68,077	$68,077	Earnings from Each Energy Efficiency Regulatory Model

However, equalizing earnings across EE regulatory recovery mechanisms may not produce the same result as earnings from construction of capacity. This impact can be evaluated by comparing *NI* under a traditional revenue requirement model to earnings via the EE regulatory recovery mechanisms. Using the alternative specification of *NI* given by equation (5), the impact of the alternate recovery mechanisms on *NI* can be specified as follows:

Traditional Model

(5) $NI = w \cdot roe \cdot RB(Q)$

EE Regulatory Recovery Mechanisms

(13) $NI(SS) = w \cdot roe \cdot RB(Q - Q(EE)) + s \cdot (AC - PC) \cdot Q(EE)$
(14) $NI(PPC) = w \cdot roe \cdot RB(Q - Q(EE)) + p \cdot (PC) \cdot Q(EE)$
(15) $NI(PAC) = w \cdot roe \cdot RB(Q - Q(EE)) + (z \cdot AC - PC) \cdot Q(EE)$

Based upon these equations, we can identify the conditions necessary to equalize the earnings between the traditional asset-driven regulatory model and the earnings under each of the EE regulatory recovery mechanisms. To begin, after adding and subtracting *Q(EE)* to the rate base portion of equation (5) produces the following:

(5') $NI = w \cdot roe \cdot RB(Q - Q(EE) + Q(EE))$

This allows us to identify what the earnings must be under the EE Regulatory Recovery Mechanism to match that under the Traditional Model. Setting equation (5') equal to each of the *NI* equations (13) to (15) yields the following conditions:

Traditional Model vs. Shared Savings
(16) $w \cdot roe \cdot RB(Q(EE)) = s \cdot (AC - PC) \cdot Q(EE)$

Traditional Model vs. Percent of Program Costs

(17) $w \cdot roe \cdot RB(Q(EE)) = p \cdot (PC) \cdot Q(EE)$

Traditional Model vs. Percent of Avoided Costs

(18) $w \cdot roe \cdot RB(Q(EE)) = (z \cdot AC - PC) \cdot Q(EE)$

To make sense of these equations requires an assessment of the relative level of rate base foregone due to *Q(EE)* and the size of *AC* and *PC*. Since *AC* includes avoided production cost as well as capital cost, one would expect that *AC* would be larger than *RB(Q(EE))* for EE programs that are cost-effective. The relationship between *roe* and *s*, *p*, and *z* will depend upon those relative values of *AC* and *PC* and the portion of *AC* equal to the capital associated with *RB(Q(EE))*.

Letting *k* equal the percentage of *AC* that is associated with rate base or capacity and assuming this represents the capacity foregone through the implementation of EE, then *s*, *p*, and *z* can be defined such that the earnings from EE will match the level of earnings foregone from not increasing the rate base. If $k \cdot AC$ is the proportion of total avoided cost associated with capacity (i.e., the foregone additions to rate base), then this can be substituted into equations (16) through (18) in order to solve for *s*, *p*, and *z*. This produces the following[8]:

(19) $s = w \cdot roe \cdot k / ((AC - PC) / AC) = w \cdot roe \cdot k /(1-(1 / UCT))$

where, $(AC - PC) / AC$ represents the proportion of avoided costs that exceeds the EE program costs.

This effectively means that *s* must be increased above the return on rate base for that proportion but scaled down depending on the split of avoided costs between energy and capacity. For example, if the UCT for the portfolio were 2.0, then the proportion $(AC - PC) / AC$ would equal 0.5. Also, if the split of avoided costs is 50/50 energy and capacity, then $k = 0.5$.

Thus, using equation (19), $s = w \cdot roe \cdot 0.5 / 0.5 = w \cdot roe$ or in other words, setting shared savings equal to the weighted return of equity on rate base would equalize earnings. However, there is one major caveat. The earnings from an addition to rate base are not a one year event, while the earnings from shared savings occur for only one year. So, the rate of return, roe, must be estimated as if the asset's lifetime earnings occurred in one year. This adjustment to *roe* is addressed in Section III.

Continuing with the equations (17) and (18), we find the adjustments to *roe* needed for *p* and *z* are:

(20) $p = w \cdot roe \cdot k \cdot UCT$

and

(21) $z = w \cdot roe \cdot k + (1 / UCT)$

For these last two cases, again assuming $k = 0.5$ and the UCT is 2.0, we would calculate $p = w \cdot roe \cdot 0.5 \cdot 2.0 = w \cdot roe$; and $z = w \cdot roe \cdot 0.5 + 1.0 / 2.0 = 0.5 \cdot w \cdot roe + 0.5$. Again, the relationships between these

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[8] To facilitate the computations, we incorporate the *Q(EE)* value into the variables for *AC* and *PC*. In other words, *AC* and *PC* change from a unit value to a total value to make the mathematics more parsimonious.

would change as the UCT portfolio value of EE changes as well as the value for *k*, the proportion of *AC* associated with capacity. The relationships derived in equations (19), (20), and (21) are depicted graphically in Figures 12, 13, and 14, respectively.

Figure 12 - One Period % Return on Equity & Shared Savings %

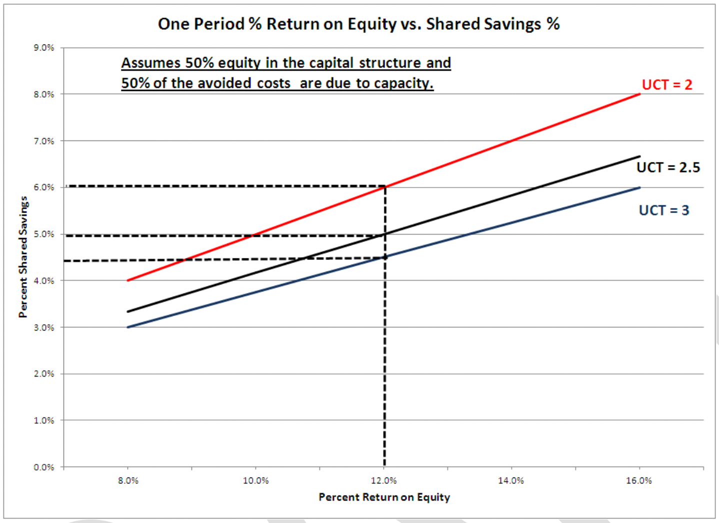


Figure 13 - One Period % Return on Equity & Program Cost %

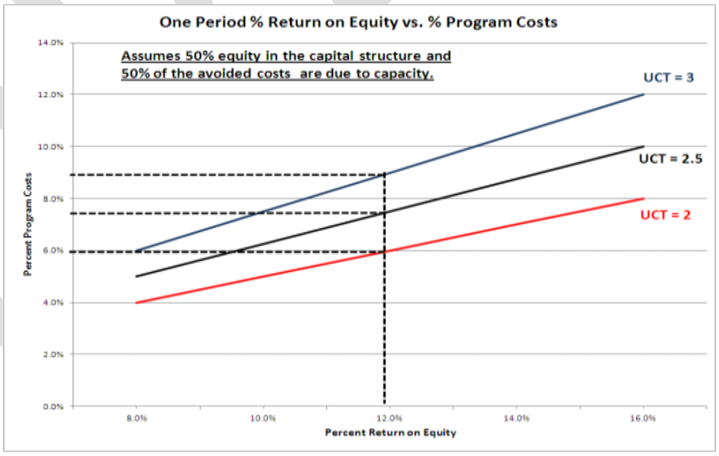
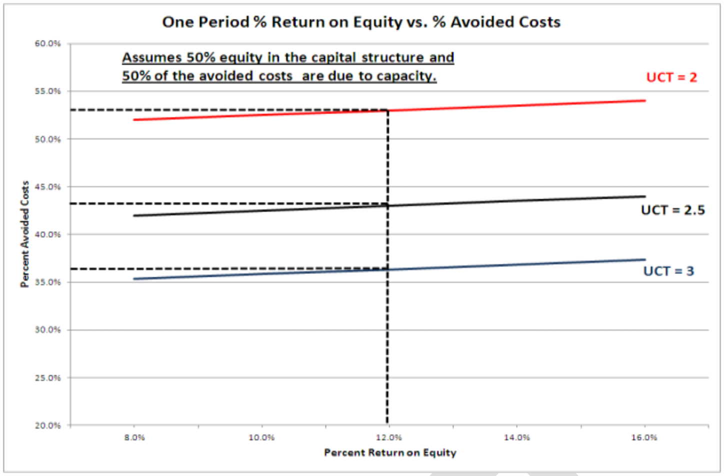


Figure 14 - One Period % Return on Equity & Avoided Cost %

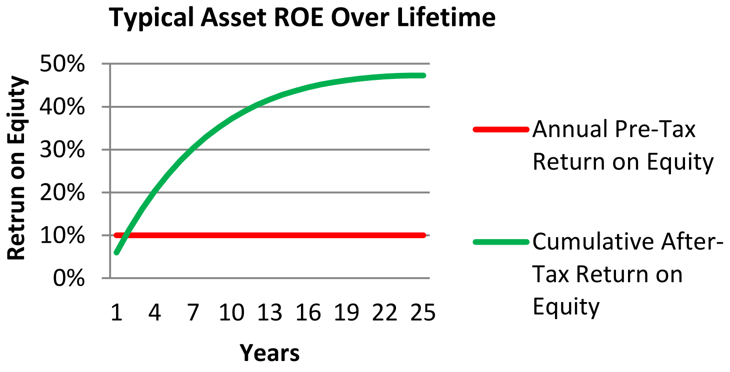


III. Lifetime Rate of Return for Utility Investments in Assets

As previously mentioned, the traditional regulatory compact requires utilities to supply electricity to all customers in exchange for full recovery of their prudently-incurred variable and fixed costs and an opportunity to earn a return on their investments in assets. Because utilities are monopolies, regulators prevent pricing abuses by managing a utility's earnings, i.e., by determining a "fair" annual rate of return for its investments in assets. For reasons of prudency and economics, utilities are further limited in how much they can grow earnings because they cannot build an infinite amount of assets. Yet, investors in publicly-traded utilities require year-over-year earnings growth to justify their ownership of utility equity. As such, utility chief financial officers (CFO's) must find ways to grow earnings prudently to maintain the financial health of the utility. Thus, utility CFO's have access to a limited amount of funds to invest and must evaluate (among other things) the cash flow and cash earnings implications of a particular asset or EE program.

As previously discussed, the traditional regulatory model allows a utility to recover an asset's costs and earn a return on its investment over many years. Using this regulatory model, an asset will operate for many years while generating a total cash return over its life that is greater than its authorized annual return (see Figure 15). The lifetime equity rate of return depends upon the cost of equity, the life of the asset, and the capital structure.

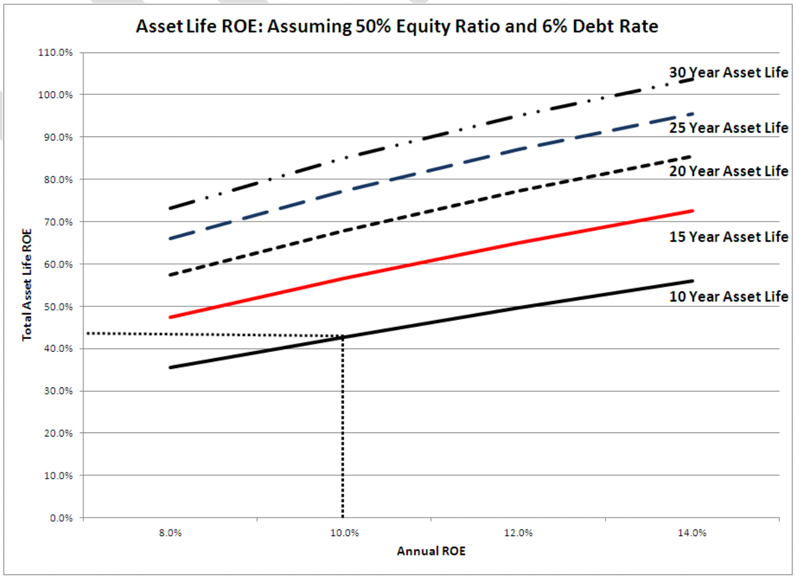
Figure 15 – Return on Equity



Note that even though the utility is authorized to earn an annual ROE of 10% in this example, over the lifetime of the asset, the utility's actual return on the total initial investment is significantly higher. Thus, the weighted equity rate of return, $w \cdot roe$, on rate base, allowed by regulatory agencies, is for the un-depreciated value of the asset for the life of the asset. The present value of the earnings from an investment in rate base will be higher as a percentage of the initial dollar investment in rate base than the annual rate of return since the earnings occur for multiple years. Utilizing the present value of the lifetime asset earnings must be incorporated into the analysis to truly make equations (19) through (21) produce earnings from EE that are equivalent to earnings from investments in assets.

Figure 16 graphically presents the relationship between the return on equity over the lifetime of the asset (for varying asset life) relative to the return on equity as a component of the rate of return. For example, if the one year ROE is 10%, for an asset with a ten year life that is financed with 50% equity, the asset life ROE is 42.8%. This represents the cumulative cash ROE earned on an asset that is depreciated over ten years.

Figure 16 – Asset Life Return on Equity



Since utilities build assets to satisfy customer demand for electricity, load growth is another important consideration in determining earnings equivalency between EE and an investment in an asset. The utility will only invest in a new asset whenever an old asset must be replaced (due to maintenance, storm damage replacement, environmental regulations, or obsolescence) or a new asset must be procured to satisfy load growth. If we assume load growth for the utility is flat or declining, the utility would only need to invest in replacement assets. Assuming the replacement assets are roughly equivalent in cost, there would be little to no earnings growth for the utility using the traditional regulatory model under a flat or negative load growth situation regardless of whether the utility pursued EE or not. On the other hand, if we assume the utility will continue to experience annual load growth, the utility will need to invest in new assets at some point in time even if electricity prices are set at marginal cost. Thus, the use of cost-effective EE can only delay, rather than permanently eliminate, the need to build new assets. Therefore, in order to determine equivalency, the equity rate of return, *roe*, needs to reflect the difference in total earnings from not building an asset. This modifies (19) through (21) in the following ways:

(22) $s = w \cdot roe' \cdot k / ((AC - PC)/AC)$

(23) $p = w \cdot roe' \cdot k \cdot UCT$

(24) $z = w \cdot roe' \cdot k + (1/UCT)$

where *roe'* = weighted equity rate of return over the life of the asset at which the net present value of the cash earnings from investment in new assets equals the net present value of the cash earnings from the avoided costs associated with an equivalent-sized EE program. Said differently, *roe'* is the asset's equity weighted Internal Rate of Return (IRR).

Figure 17 – Asset Earnings Example

Year	1	2	3	4	5	. . .	20
Asset Investment	$600,000						
Beginning Net Plant	$600,000	$570,000	$540,000	$510,000	$480,000	. . .	$30,000
Depreciation	$30,000	$30,000	$30,000	$30,000	$30,000	. . .	$30,000
Ending Net Plant	$570,000	$540,000	$510,000	$480,000	$450,000	. . .	$0
Interest Expense	$11,700	$11,115	$10,530	$9,945	$9,360	. . .	$585
Equity Return	$30,000	$28,500	$27,000	$25,500	$24,000	. . .	$1,500
Total Return	$41,700	$39,615	$37,530	$35,445	$33,360	. . .	$2,085
Avoided Energy	$39,600	$39,600	$39,600	$39,600	$39,600	. . .	$39,600
Avoided Capacity	$71,700	$69,615	$67,530	$65,445	$63,360	. . .	$32,085
Total Avoided Costs	$111,300	$109,215	$107,130	$105,045	$102,960	. . .	$71,685
PV of Equity Return	$202,116						
Total Equity Return	67%	roe'					
PV of Avoided Costs	$1,021,158						
PV of Avoided Capacity	$600,000						

Figure 18 – Equalized Energy Efficiency Earnings Example

	Shared Savings	% of Program Costs	% of Avoided Cost	
(%)	**29.7%**	N/A	N/A	Revised Shared Savings %: s **(Eq. 22)**
(%)	N/A	**59.4%**	N/A	Revised Program Cost %: p **(Eq. 23)**
(%)	N/A	N/A	**53.1%**	Revised Avoided Cost %: z **(Eq. 24)**
	$202,116	$202,116	$202,116	Earnings from Each Energy Efficiency Regulatory Model

By comparing the results from Figure 11 with those in Figure 17, this exercise demonstrates that, for an EE portfolio with a UCT of 3.0, the earnings under the regulatory recovery structures of 10% shared savings, 20% of program costs, or 40% of avoided costs would fall well below the earnings from construction of a generation asset. Instead, to equalize the earnings, the regulatory structure would have to align with the values in Figure 18.

So, using the information from equations (12), (22), (23), and (24) along with the process discussed in Figures 17 and 18, the interrelationships among ROE, Asset Life ROE, shared savings percentage, percent program cost, and percent avoided cost can be identified. It should be noted that these relationships vary with the level of the EE portfolio UCT as shown below in Figure 19.

As an example, using the assumptions in Figure 19, the required return on equity for a one year period that will generate the returns equivalent to an asset with a life of ten years is 42.8%. With that as a starting point, one can see how the shared savings percentage, percent program cost, and percent avoided cost percentages must change to provide that level of earnings. Figures 20, 21, and 22 provide graphical representations for this example. The actual percentages would depend on the EE measure life in the portfolio as well as the actual capital structure and capital cost rates.

Figure 19 – Recovery Mechanism Earnings Equivalency

Asset Life	Asset Life	Shared Savings %			Percent Program Costs			Percent Avoided Costs		
Years	Equity Return	UCT = 2.0	UCT = 2.5	UCT = 3.0	UCT = 2.0	UCT = 2.5	UCT = 3.0	UCT = 2.0	UCT = 2.5	UCT = 3.0
10	42.8%	21.4%	17.8%	16.1%	21.4%	26.8%	32.1%	60.7%	50.7%	44.0%
15	56.6%	28.3%	23.6%	21.2%	28.3%	35.4%	42.5%	64.2%	54.2%	47.5%
20	67.9%	34.0%	28.3%	25.5%	34.0%	42.5%	51.0%	67.0%	57.0%	50.3%
25	77.3%	38.6%	32.2%	29.0%	38.6%	48.3%	57.9%	69.3%	59.3%	52.6%
30	85.0%	42.5%	35.4%	31.9%	42.5%	53.1%	63.7%	71.2%	61.2%	54.6%

Assumptions: 50% equity
Capacity portion of avoided costs is 50%
Equity cost is 10%
Debt cost rate is 6%
Tax rate is 40%

Figure 20 – Shared Savings Recovery Mechanism Earnings Equivalency

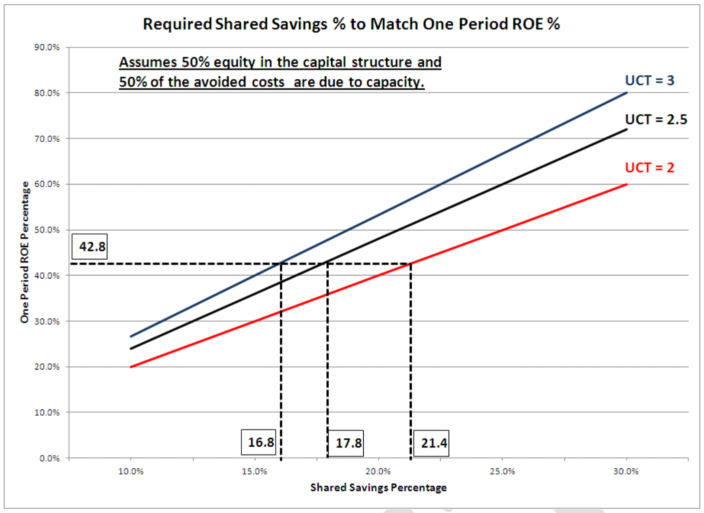


Figure 21 – Program Costs Recovery Mechanism Earnings Equivalency

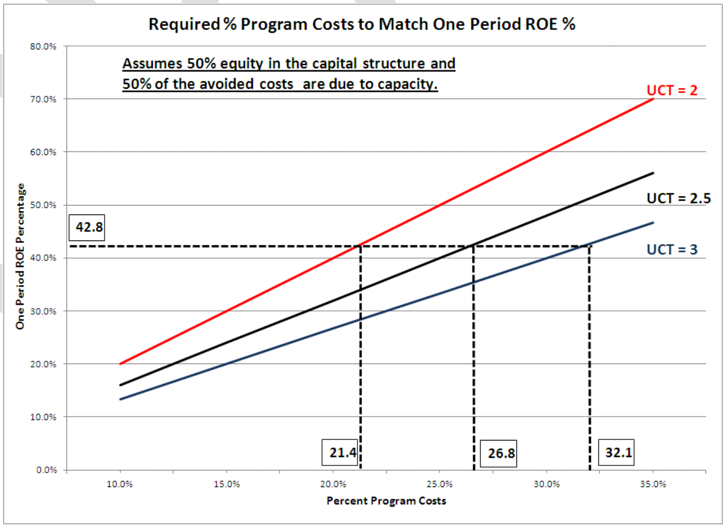
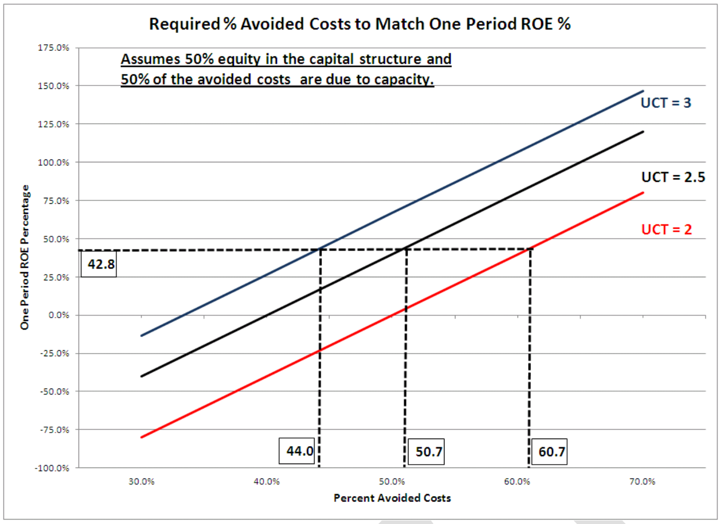


Figure 22 – Avoided Costs Recovery Mechanism Earnings Equivalency



IV. Short-Run Implications of EE on Utility Lost Margins

It is a utility's responsibility to plan and invest in plant to serve all consumer demand, even if that demand ends up at an elevated level relative to that considered economically efficient. Regardless of whether the utility or a third-party is responsible for implementing EE programs, the utility retains a responsibility to create and maintain adequate supply to meet estimated future load. Thus, when utilities must make investments in supply-side resources, an effort to reduce consumption can create short-term earnings pressure on the utility, since the costs for existing assets do not disappear as load drops. The fixed costs and returns associated with these existing investments are known as lost margins, and they represent a short-term impediment to implementation of EE. Therefore, regulators must address lost margins by including some mechanism to keep the utility financially whole, no matter who is responsible for implementing EE programs. With minor alterations, equation (1) can be used to examine the need to include recovery of lost margins.

To begin, we need to subdivide *Q* into two parts as follows:

(25) $Q = Q(M) + Q(EE)$

where,

$Q(M)$ = metered economically efficient level of energy consumption
$Q(EE')$ = amount of cost-effective achieved energy efficiency

Restating equation (1) with this change yields:

(1') $RR = P \cdot (Q(M) + Q(EE')) = VC \cdot (Q(M) + Q(EE')) + FC + r \cdot RB + T + D$

Without the EE programs, total revenues above would have included *Q(M)* plus *Q(EE)*.

Now, adding the EE program impacts as a reduction of load and the EE program costs as both a revenue recovery item and a cost into equation (2) produces:

$$(2')\ NI = P \cdot (Q - Q(EE')) + PC \cdot Q(EE') - VC \cdot (Q - Q(EE')) - FC - PC \cdot Q(EE') - T - D - I$$

Upon rearranging terms, this becomes:

$$(26)\quad NI = (P - VC) \cdot Q - (P - VC) \cdot Q(EE') - FC - T - D - I$$

As such, recovery of lost margins, defined as $(P - VC) \cdot Q(EE')$, returns the utility to the same position as if the EE programs were not implemented.[9] This demonstrates (see Figure 23) that lost margins are a real cost to the utility and deserve regulatory recovery.

Figure 23 - Utility Lost Margins Example

	Results w/o EE Programs	Results w/ EE Programs	
(kWh)	1,000,000,000	1,000,000,000	Economicly-Efficient Energy Consumption Q(M)
(kWh)	0	1,000,000	Amount of Energy Efficiency Achieved Q(EE')
(kWh)	1,000,000,000	999,000,000	Quantity of kWh Sales Q
($)	$600,000	$600,000	Fixed Costs FC
($/kWh)	$0.0403	$0.0403	Electricity Rate P
($/kWh)	$0.0396	$0.0396	Unit Variable Cost VC
($)	$100,000	$99,300	Net Income NI **(Eq. 26)**

V. Long-Term Implications of EE and Utility Investments in Assets

As shown in Figure 2, when electricity prices are set at average embedded cost, utilities will need to supply an artificially-high amount of electricity. In this scenario, utilities must invest in more assets than are economically efficient in order to meet customer demand. As previously discussed, EE programs can permanently reduce customer demand in lieu of higher pricing. As cost-effective EE programs are implemented, they should reduce customer load growth until consumption approaches an economically-efficient level as if electricity were priced at marginal cost. Asset optimization achieved through implementation of cost-effective energy efficiency programs should not impair equity investor perceptions of the utility's long-term earnings growth because going forward the utility's level of assets would be at an economically efficient level.

However, if load reductions achieved from an EE program are not cost-effective (e.g. because it costs more than a comparable, new supply-side asset), additional inefficiencies will be introduced, raising electricity prices too high and causing customer demand to be artificially low. Reductions

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[9] One approach that has received considerable attention in the literature is revenue decoupling. While revenue decoupling could provide a solution for the lost margin issue, processes to implement decoupling are complex and never perfect and even less so for non-residential customer classes. A simpler approach would be to implement a formula rate setting process that allows annual true-ups.

achieved in this manner should be avoided because they impair the utility's long-term earnings and further undermine efforts to achieve an economically-efficient level of pricing and consumption.

In the long-term, efforts to reduce consumption and system investment to the economically efficient level will never be fully successful as long as utility commissions continue to set rates at average embedded cost (i.e., below marginal cost). Much like Sisyphus continuing to push a rock up a hill, utilities must struggle to reach the economically-efficient level of investment but continually find it out of reach due to the price-induced elevated level of consumption.

VI. Future Research

The analyses in this paper highlight how to generate earnings equivalency between a return on equity on assets and earnings from a percent of shared savings, program costs, or avoided costs for investments in EE. This presumes that there is also equivalency in the risk of investment in EE versus the risk of investment in new assets. As a result, one must consider the question as to whether or not a risk adjustment (either up or down) should be applied to any of the EE recovery mechanism percentages. This is an area of research for future investigation.

VII. Conclusions

Energy efficiency has not been universally embraced despite recognition that it can reduce consumption to a more economically-efficient level. Furthermore, EE has been implemented to varying degrees, utilizing a wide range of regulatory approaches, including mandated levels of EE achievement. Regardless of the state or regulatory mechanism, one of the primary impediments to EE adoption has focused on determining what (if any) incentives should be paid to utilities.

As long as utilities are required to meet projected customer demand with adequate supply, new assets will need to be built. If a utility continues to experience positive load growth after implementing EE programs, a decision to build such an asset may be delayed, rather than eliminated. Alternatively, reductions from EE may necessitate the construction of a different asset altogether. Regardless of the outcome, utilities will only need to build assets to a level that is economically efficient as long as only cost-effective programs are implemented. Thus, with proper regulatory treatment, utilities should continually pursue cost-effective EE in order to reduce demand toward an economically-efficient quantity.

Over the short-run, regulators can bridge the earnings gap from an inefficient to an efficient market by compensating the utility for its lost margins as in (26) and providing a sufficient return as shown in Equations (22) through (24). Such regulatory recovery prevents the utility from being financially harmed by this transition. Yet, regulators should be cautious about requiring implementation of EE that is not cost-effective. Arbitrary energy efficiency resource standards or mandates will introduce additional market inefficiencies that ultimately harm consumers and leave the energy market once again with an artificial level of demand and investment. Similarly, failing to provide the utility with a financial incentive to cover its short-tem earnings losses derived from the implementation of EE, will financially harm utility companies and create unnecessary risks for suppliers of electricity. Lastly, failure to adopt a regulatory mechanism to assist the utility recovery of lost margins from assets delayed by EE, regardless of what entity actually delivers EE programs to customers, can erode the utility's financial health and create artificial, unnecessary barriers to the adoption of EE.

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