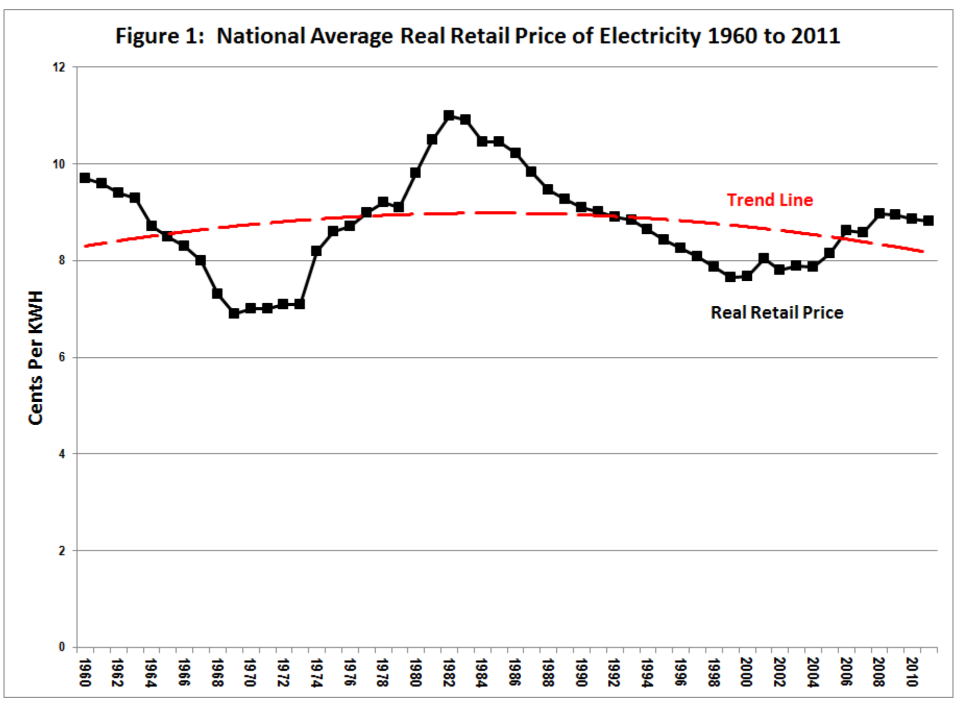
Energy Efficiency: Unmasking Recovery Mechanisms

Richard G. Stevie, Vice President Forecasting, Integral Analytics
Raiford L. Smith, Director, Smart Grid Emerging Technology, Duke Energy

The Energy Efficiency Recovery Mask

How do energy efficiency regulatory mechanisms work? What do they have in common? How do they differ? While shared savings, percent of program costs, and percent of avoided costs have been adopted by utility commissions in one form or another across the country, differences in structure affect their desirability for encouraging utilities to invest in energy efficiency. What is the desired level of energy efficiency investment? Can an economically preferred level of energy efficiency be achieved? Or will it always be out of reach?

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.



[1] Source is the Energy Information Administration, Table 8.10: Average Retail Prices of Electricity, 1960-2011.

However, one historically-recognized issue with this regulatory construct is that electric prices are set artificially low at the utility's average embedded cost. This pricing is a result of the cost-based, retrospective nature of utility regulation as well as a desire to provide low electricity rates that encourage economic growth and promote social welfare. As noted by Alfred Kahn,[2] electric utility customers with embedded-cost pricing 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-offs 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]

Figure 2 shows how this over-consumption can be deconstructed into two components. The first part of over-consumption (the shaded area labeled A in Figure 2) shows the difference in the quantity demanded due to pricing at embedded average cost versus pricing at current average cost, (Q(AC-E) – Q(AC-C))[4]. Current average cost represents a reproduction cost that accounts for the difference between the original cost of construction and the current replacement cost. The second portion of over-consumption (the shaded area labeled B in Figure 2) is the change in quantity demanded due to pricing at current average cost versus pricing at current marginal cost, (Q(AC-C) – Q(MC-C)). When summed together, the total level of a consumer's over-utilization can be measured by the sum of the two parts, (Q(AC-E) – Q(MC-C)). However, current marginal costs are not always above either current average cost or embedded average cost. Because utilities must build assets to serve peak demand as well as base load assets for constant demands, there will be instances during a year where current marginal costs can be either below or above the current average cost. But, when utility resources during peak demand are scarce, current marginal costs will rise well above current average cost or embedded average costs. Growth in peak demand is a major driver for the need to build new capacity.

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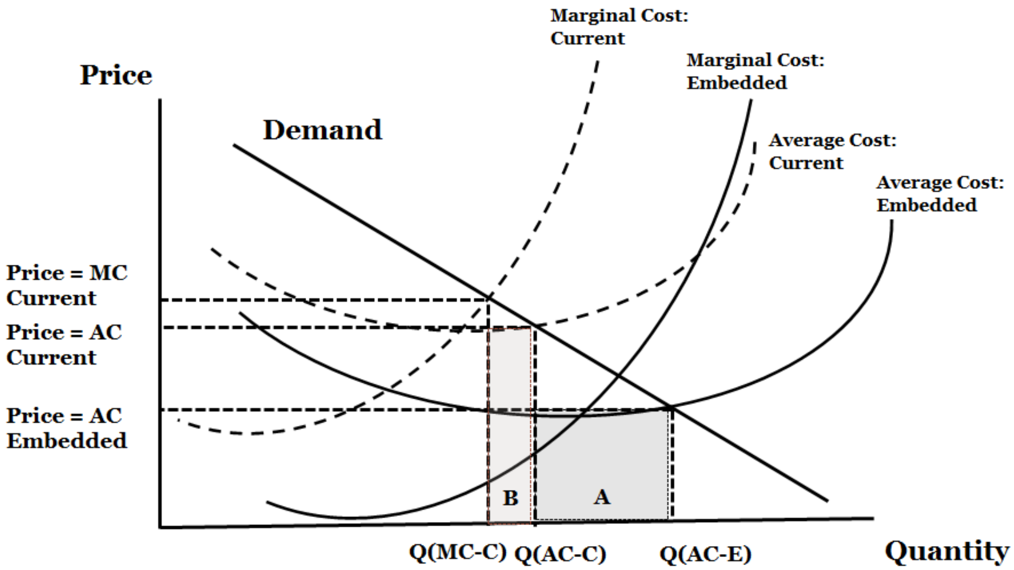
[2] See Kahn, Alfred E. The Economics of Regulation: Principles and Institutions, Volume 1. (New York, NY: John Wiley & Sons, Inc., 1970), Page 110 where he states in reference to marginal costs: "…under original cost valuation the buyers pay not these, but some lower average as the cost of new, increasingly expensive plant is blended in with that of the old, the result is excessively large purchases of the public utility service and correspondingly excessive flow of resources into its supply". Some states have established fair value as the base for establishing a rate base, but this does 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.

[4] Where Q(AC-C) represents the volume demanded with price set equal to current average costs and Q(AC-E) represents the volume demanded with price set equal to embedded average costs.

Figure 2: Consumption of Electricity at Embedded and Marginal Costs

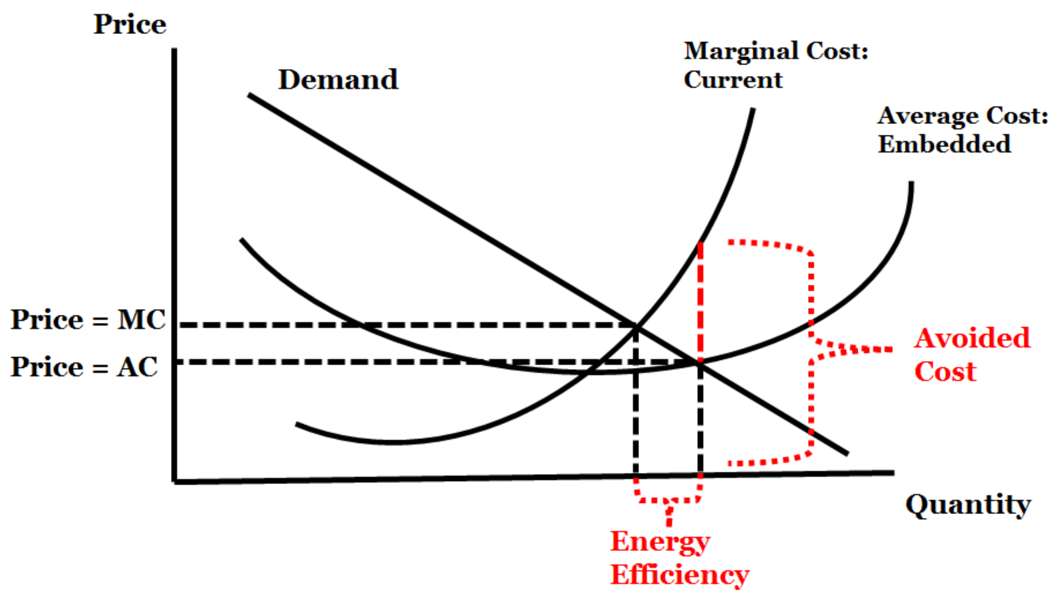


When utilities charge electricity prices set below their marginal costs, customers historically have demanded more electricity than what is considered economically efficient (e.g. the quantity that would be supplied if prices were set at marginal current cost). At the same time, utilities are charged by regulators to provide reliable and affordable service by pricing electricity at an embedded average cost, necessitating additional utility 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 in the 1970's and 1980's to incorporate EE programs in the generation planning process and economically reduce expected future loads. Cicchetti[5] supports the concept that pricing below marginal current costs is related to consumer over-consumption, pointing out that if prices are set at or above marginal costs, there would be little cost justification for regulators to require utility sponsored energy efficiency programs.

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: note that the avoided cost captures the total difference between marginal current and average embedded cost). 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 current cost.

[5] Cicchetti, Charles J., Going Green and Getting Regulation Right. (Vienna, VA, Public Utilities Reports, Inc., 2009), pp 122 to 125.

Figure 3: Consumption Reduction After Implementation of Energy Efficiency



While this relationship is not new, it highlights the fundamental basis for the cost-effectiveness of energy efficiency programs for ratepayers as well as utilities. However, the financial consequences are not aligned between ratepayers and utility management and shareholders. For ratepayers, energy efficiency programs can forestall the need for investment in new assets and can delay the need for rate increases. For utilities, EE programs will reduce utility earnings in the short-run and may reduce the long-term growth rate of the company. This is an important distinction because investing in new assets versus EE programs can produce very different financial results. Consideration of the earnings impacts of investments in EE becomes important for utility management as well as regulators. 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[6]. 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 that is closer to being economically "right-sized" or efficient. Since regulatory policy seems to favor encouraging EE programs while setting electric rates below the marginal current cost of production, utilities will be forced to manage under contradictory or competing objectives (e.g. satisfying artificially-high demand while pursuing programs that undermine growth in demand).

These contradictory objectives raise the following questions:

> How should utilities be compensated for EE programs that reduce consumer demand for electricity?

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

Should utilities be allowed to recover the cost of existing investments (e.g. lost margins)?

Can a utility be successful over the long run in reducing customer demand to an economically-efficient level?

Answers to these questions can be obtained through the construction of a theoretical model to examine the financial outcomes to a utility that pursues EE versus a utility that builds supply-side assets to satisfy customer demand. The theoretical model also helps compare one EE regulatory recovery mechanism with another.

Utility Compensation for Reducing Consumer Demand for Electricity

EE programs function as assets in that they produce results (e.g. energy and capacity reductions) for customers over many years. By making specific adjustments to a utility financial model, one uncovers the impact on utility earnings under alternate regulatory recovery mechanisms for EE programs. The objective in this section is to understand how these regulatory recovery mechanisms operate relative to one another.

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. The word "reasonable" is used 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 points out the key drivers of revenue requirements, i.e., fixed and variable costs, return on rate base, taxes, depreciation and earnings (kWh sales and the level of rate base) for the utility. 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) $NI = P \cdot Q - VC \cdot Q - FC - T - D - I$

where:

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

Taking a total differential of (2) produces:

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

Assuming no price changes, relatively constant unit costs, and no change in taxes[7], then set $\Delta P = 0$; $\Delta VC = 0$; $\Delta D = 0$, $\Delta I = 0$, and $\Delta T = 0$. This reduces ΔNI to:

(4) $\Delta NI = P \cdot \Delta Q - VC \cdot \Delta Q - \Delta FC$
$= (P - VC) \cdot \Delta Q - \Delta FC$

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

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.[8]

[7] While a simplifying assumption, revenue requirements are generally adjusted to cover tax effects in a rate proceeding. Changes in taxes do not affect the underlying strategy relative to changes in net income.
[8] 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

These regulatory models include: shared savings, percent of program costs, and percent of avoided costs.[9]

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

where,

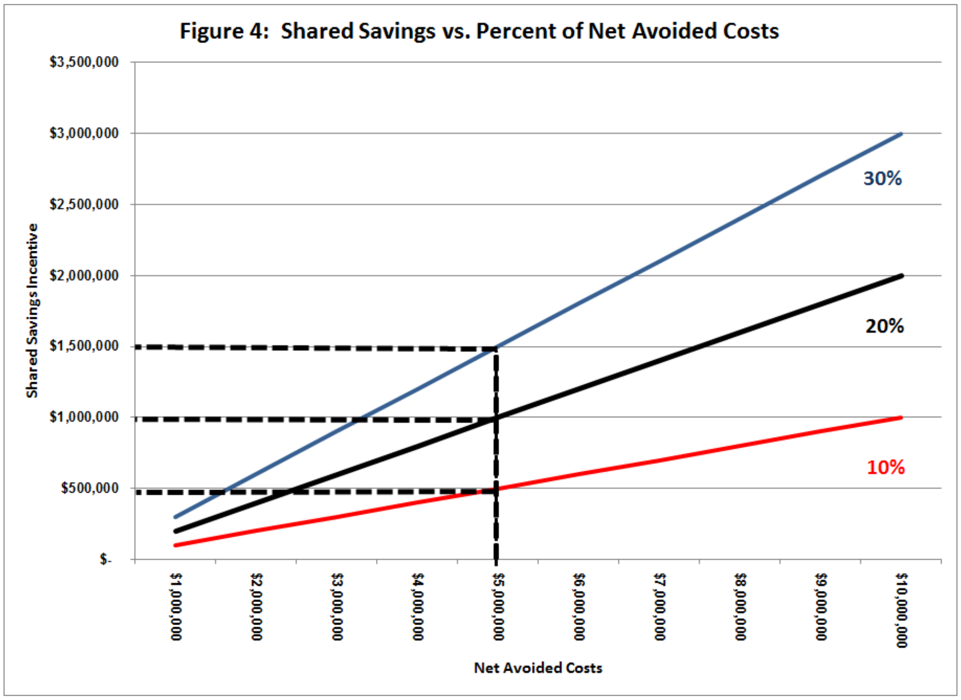
SS = shared savings incentive
s = shared savings percentage
AC = PV (avoided costs) per unit of EE
PC = PV (EE program costs) per unit of EE
Q(EE) = amount of achievable energy efficiency or demand-side management

Q(EE) represents the difference between Q(AC-C) and Q(MC-E) 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 Utility Cost Test (UCT) of the program or portfolio of programs (a reflection of the cost-effectiveness) and the shared savings percentage.

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).

[9] 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.



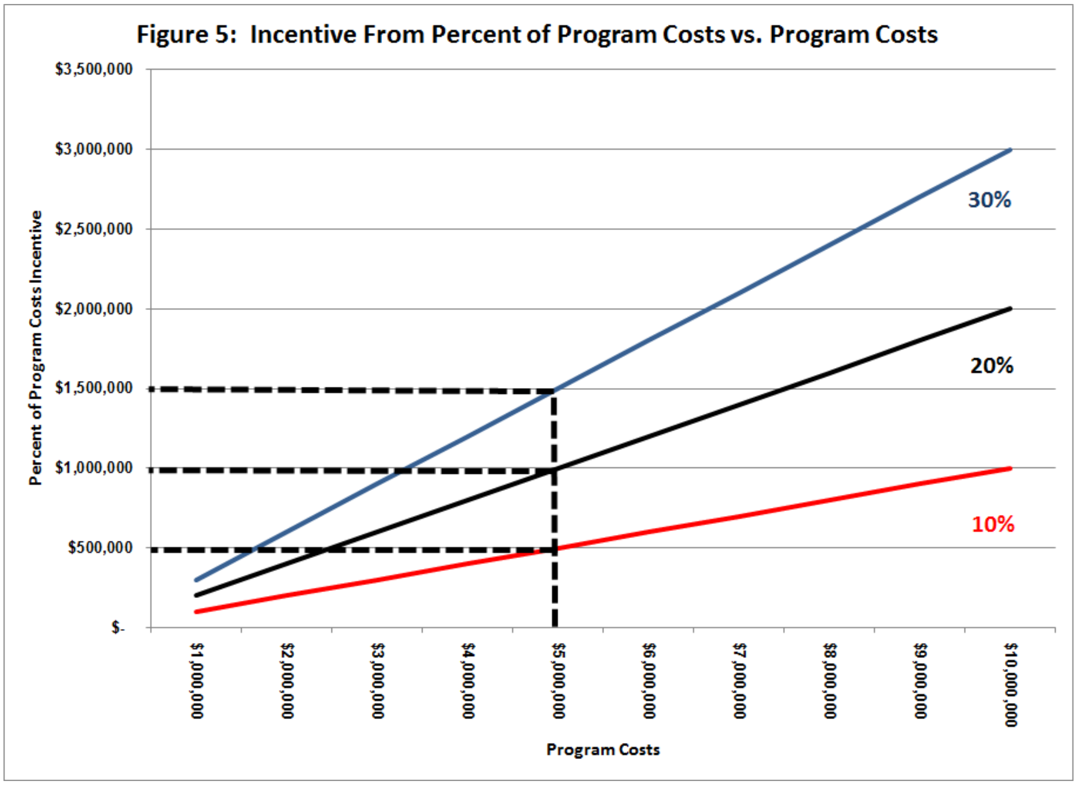
The percent of program cost regulatory mechanism provides the utility with a financial incentive based on a set percentage of EE program costs. This can be expressed as:

(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.



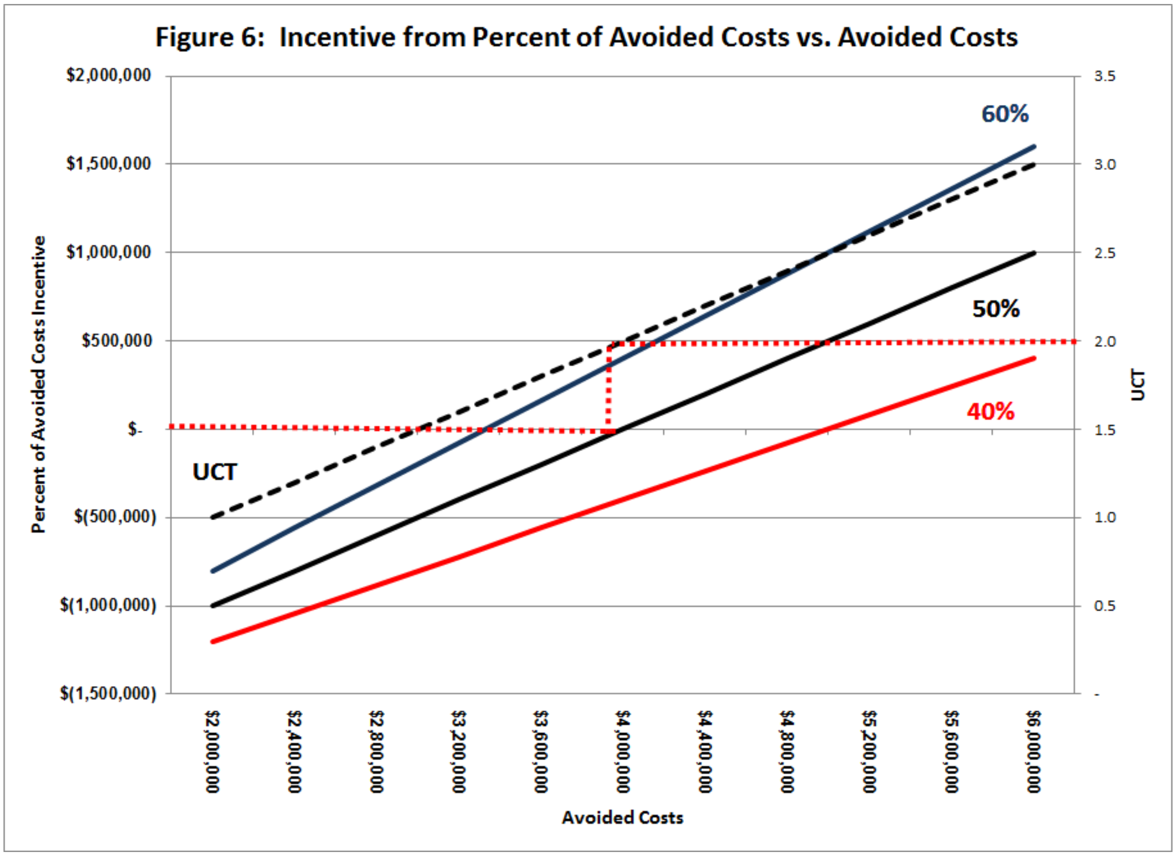
Lastly, the percent of avoided cost regulatory mechanism is different (and riskier for the utility) from the previous two mechanisms because there is no explicit recovery of EE program costs. Under this approach, revenues are computed as a percent of the present value of the avoided costs. However, the 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*.



While each of the methods may include recovery of lost margins, discussion of the issue of lost margins due to reductions in utility sales is deferred to the next section.

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

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

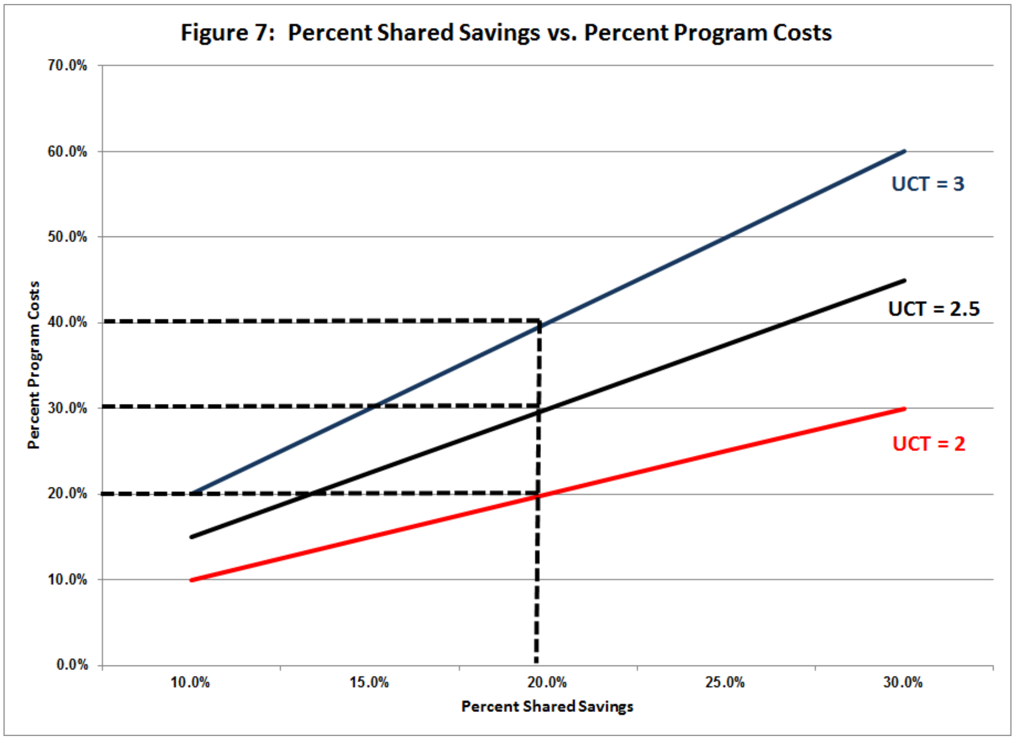
Based upon these equations, the conditions that would equalize the incentive to the utility across the separate mechanisms are the following:

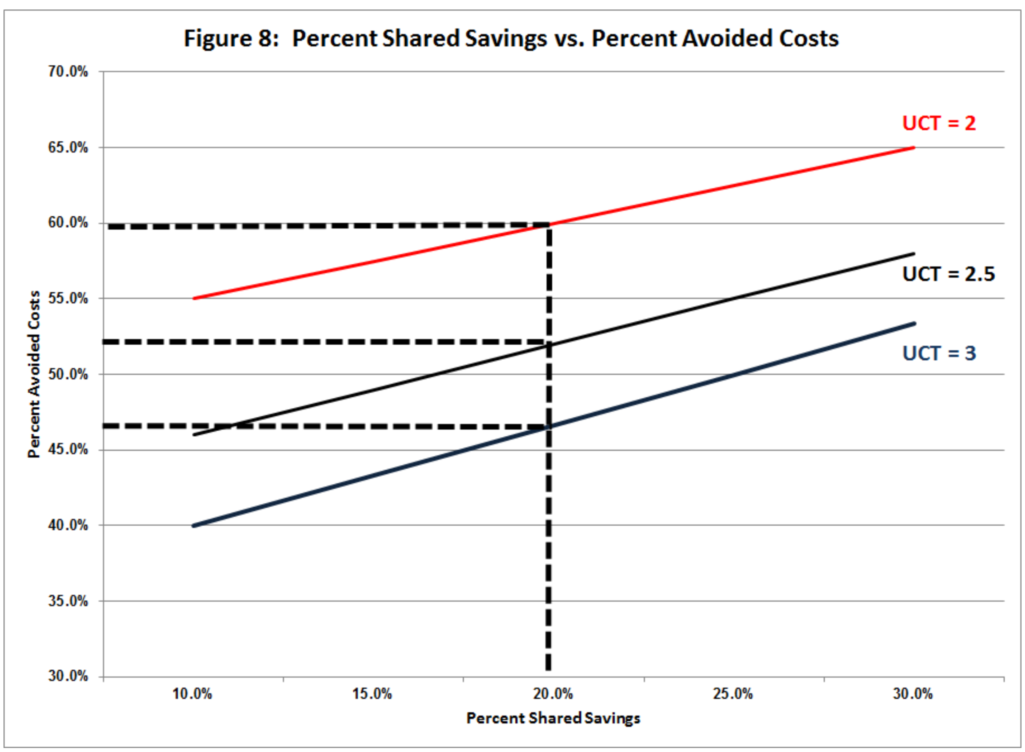
	<u>SS</u>	=	<u>PPC</u>	=	<u>PAC</u>
(12)	s	=	p /(UCT – 1)	=	(z · UCT – 1) / (UCT – 1)

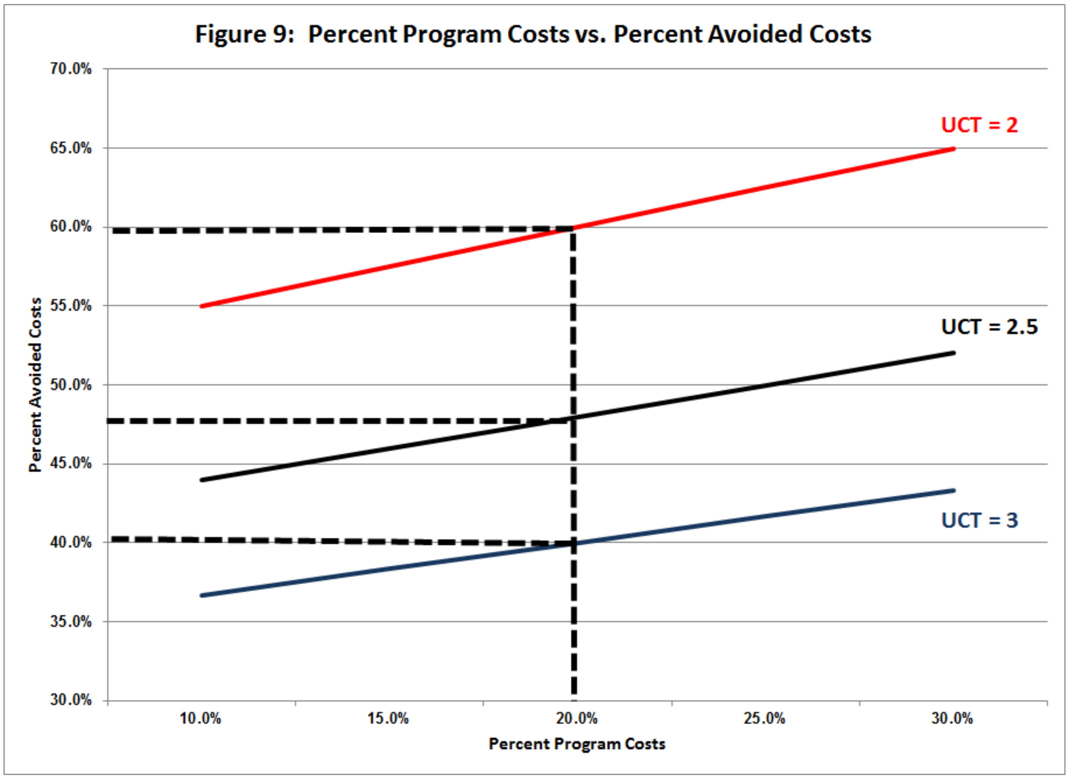
where,

UCT = utility cost test or (AC / PC)

Alternatively, in terms of s, p = s · (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%.







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.[10] 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.

Changes to the assumptions will obviously alter the results, but the examples provide insights on the interrelationships across the different energy efficiency regulatory recovery mechanisms.

Figure 10: Example of Earnings Under Each Regulatory Recovery Model with UCT = 2

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

[10] 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: Example of Earnings Under Each Regulatory Recovery Model with UCT = 3

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

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 have made 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.

The severity or even the existence of the negative financial consequences of lost margins from the implementation of energy efficiency programs has been debated many times before utility regulatory commissions. Whether or not one believes in the existence of lost margins, it is an issue for utilities and represents an impediment to the implementation of energy efficiency measures and programs. As such, it has become an issue that regulators have tackled by either ignoring, implementing a form of decoupling, or allowing recovery of lost margins for a period of time as a mechanism to keep the utility financially whole.

With minor alterations, equation (1) can be used to examine the need to include recovery of lost margins.

To begin, subdivide Q into two parts as follows:

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

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 be based upon 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:

$$(14) \ NI = (P - VC) \cdot Q - (P - VC) \cdot Q(EE') - FC - T - D - I$$

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.[11] This demonstrates (see Figure 12) that lost margins are a real cost to the utility and deserve attention by regulatory agencies.

Figure 12: 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)	100,000,000	100,000,000	Amount of Achievable Energy Efficiency Q(EE)
(kWh)	0	1,000,000	Amount of Energy Efficiency Achieved Q(EE')
(kWh)	1,100,000,000	1,099,000,000	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. 14)

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 will 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

[11] 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 current 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.

Future Research

The analyses in this paper highlight how to evaluate earnings equivalency from a percent of shared savings, program costs, or avoided costs for investments in EE. This ignores the question of the appropriate level of earnings that a utility should be allowed an opportunity to earn for implementing energy efficiency. Should it be set at a level equivalent to that on an asset or at a different level? This presumes that there is also equivalency in the risk of investment in EE versus the risk of investment in new assets. Is there a difference in the level of risk associated with the implementation of energy efficiency? Should there be an adjustment (either up or down) applied to any of the EE recovery mechanism percentages to account for those differences if they exist? These questions are an area of research for future investigation.

Unmasked

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 recovery mechanism, one of the primary impediments to EE adoption has focused on determining what (if any) incentives should be paid to utilities. This paper provides the tools to enable one to assess the level of incentive across different regulatory recovery mechanisms.

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 need to build assets to a level that is above the economically efficient level as long as only cost-effective programs are implemented and rates are set on embedded costs. With appropriate regulatory treatment, utilities will pursue cost-effective EE in order to reduce demand toward the economically-efficient quantity.

Regulatory policies that create efficiency resource standards may raise concerns about implementation of EE that is not cost-effective. Arbitrary energy efficiency resource standards or mandates introduce new market inefficiencies that ultimately harm consumers and leave the energy market once again with an artificial level of demand and investment.

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