Utility System Benefits of Energy Efficiency: Current Experience in the U.S.

Brendon Baatz, American Council for an Energy-Efficient Economy, Washington D.C.

Abstract

Energy efficiency programs provide a wide range of benefits to program participants, utility systems, and society as a whole. While the valuation of some of these benefits is relatively straightforward, valuing others presents unique challenges. However, it is critical to include all relevant benefits in benefit-costs analysis to ensure an optimally efficient level of energy efficiency deployment in a utility service territory. If energy efficiency is undervalued and under deployed, utility systems will incur higher costs and customers will pay higher rates.

This report details the wide range of benefits of energy efficiency to the U.S. electric utility system, including traditional avoided cost of energy as well as many other economic benefits including non-energy benefits. The report examines the range of values for each benefit while also detailing the difference in specific methodologies employed to value benefits. For this research, we reviewed benefit quantification methods and assumptions for twenty-four states in the United States. The review is not limited to existing methods but also provides specific information regarding the value of these benefits in various regions of the county.

Many states lack coherent policy regarding which utility system benefits should be included in cost-effectiveness testing. As a result, utilities and jurisdictions omit relevant benefits, leaving cost-effective energy efficiency and significant cost savings on the table. The goal of this review is to provide policymakers with ample evidence of the quantification and value of these benefits. The report provides a strong foundation of the benefits, quantitation methodologies, and existing values used by program administrators in the United States today.

Introduction

We define utility system benefits as the energy and nonenergy benefits accruing to the utility system, and all customers in that system. Table 1 illustrates the utility system benefits we discuss in this paper. For example, utility system benefits include traditional avoided costs such as avoided energy and capacity as well as other benefits of implementation of energy efficiency programs. These benefits include avoided or deferred T&D infrastructure, which can be substantial and extend to all ratepayers in a utility system through reduced rates in later years. While avoided energy and capacity costs are a critical component, utility system benefits are more than just these avoided costs.

Table 1. Utility system benefits

Benefit	Description
Avoided cost of energy	Avoided marginal unit of energy produced
Avoided cost of capacity	Avoided cost of generating capacity
Avoided cost of T&D	Value of avoiding or deferring the construction of additional T&D assets
Avoided cost of ancillary services	Value of avoided ancillary services required to operate. A primary example would be spinning reserves.
Avoided cost of environmental compliance	Avoided cost of compliance with existing and future environmental regulations

Benefit	Description
Demand reduction induced price effects (DRIPE)	Value of energy or capacity market price mitigation or suppression resulting from reduced customer demand
Utility nonenergy benefits	Value of cost savings to a utility from energy efficiency programs. These benefits include reduced arrearage carry costs, reduced insurance premiums, or reduced cost of reconnections
Avoided cost of renewable portfolio standards	Value of a reduced cost of compliance with renewable portfolio standards as electricity sales decrease

Methodology

For this study we reviewed publicly available energy efficiency planning and evaluation materials and integrated resource planning studies in over half of the US states. Although we did not try to collect data from every state, we covered program administrators in nearly every region of the country. Our review focused on information and data specific to the benefits calculated for energy efficiency programs. We also examined relevant state public service commission orders and recent national studies. Based on our findings, we discuss each utility system benefit of energy efficiency in detail, specifically how prevalent it is in program screening and the methodology used to estimate it.

Avoided Cost of Energy

Typically, avoided cost of energy is the avoided cost of a wholesale market energy purchase or the avoided cost of production, generally composed of fuel and avoided variable operations and maintenance costs. In the context of energy efficiency program evaluation, the avoided cost of energy is the marginal cost of production for the incremental unit of energy avoided through an energy efficiency program. There are differences between short- and long-run avoided costs of energy. In the short-run, the avoided cost of energy is the avoided unit cost on the market or unit production cost. Long-run avoided cost of energy may change as the source of avoided energy changes over time. For example, a short-run avoided cost of energy might be based on the marginal cost of production from a simple combustion turbine (CT). This cost is based on the known cost of fuel. A long-run avoided cost of energy might be based on the marginal cost of building and operating a combined cycle gas turbine (CC). A CC has lower variable costs of operation than a CT but a higher capital cost.

Methodologies to Estimate Avoided Cost of Energy

All states, jurisdictions, and utilities in our review included avoided cost of energy as a system benefit in cost-effectiveness screening. As expected, the avoided cost of energy values and methodologies differed by company and region; however there are two overarching approaches. First, unbundled utilities operating in wholesale energy market environments typically estimate avoided cost of energy using forward market forecasts and base avoided cost of energy on avoided market purchases. Second, most vertically integrated utilities outside of competitive wholesale markets use integrated resource planning modeling to estimate future avoided energy costs. These companies typically own and operate power plants. Integrated resource planning methodologies rely on comprehensive whole system modeling using assumptions of fuel prices, environmental regulations, weather data, forecasted demand, and other factors to determine future marginal prices.

Significant variance exists between the two overarching methodologies. While all integrated resource planning relies on modeling an entire production system to determine future prices, methodological approaches differ substantially among utilities or regions utilizing this approach, as does the extent to which T&D costs are included. The same is also true for companies and regions forecasting future market prices to estimate the avoided cost of energy. Finally, there are examples of jurisdictions that do not rely on integrated resource planning or wholesale energy market prices. Pennsylvania and New Jersey, for example, use forward projections of natural gas prices to estimate future avoided energy costs. Other methodological differences exist between jurisdictions. The most significant of these differences are variances of avoided cost of energy based on time of day or season, inclusion or assumptions related to line losses, and inclusion of costs related to compliance of environmental regulations. We discuss each of these differences later in this report.

Range of Avoided Energy Cost

We collected 20 observations for avoided cost of energy used in energy efficiency program screening. Figure 1 presents the range of estimated avoided cost from 2015 to 2030 for the 20 observations. The left side of each bar shows the 2015 nominal value; the right side shows the 2030 nominal value. The values are from publicly available data and do not represent a comprehensive list. The figure also does not include values for all examples listed above, as all methodological examples did not include values.

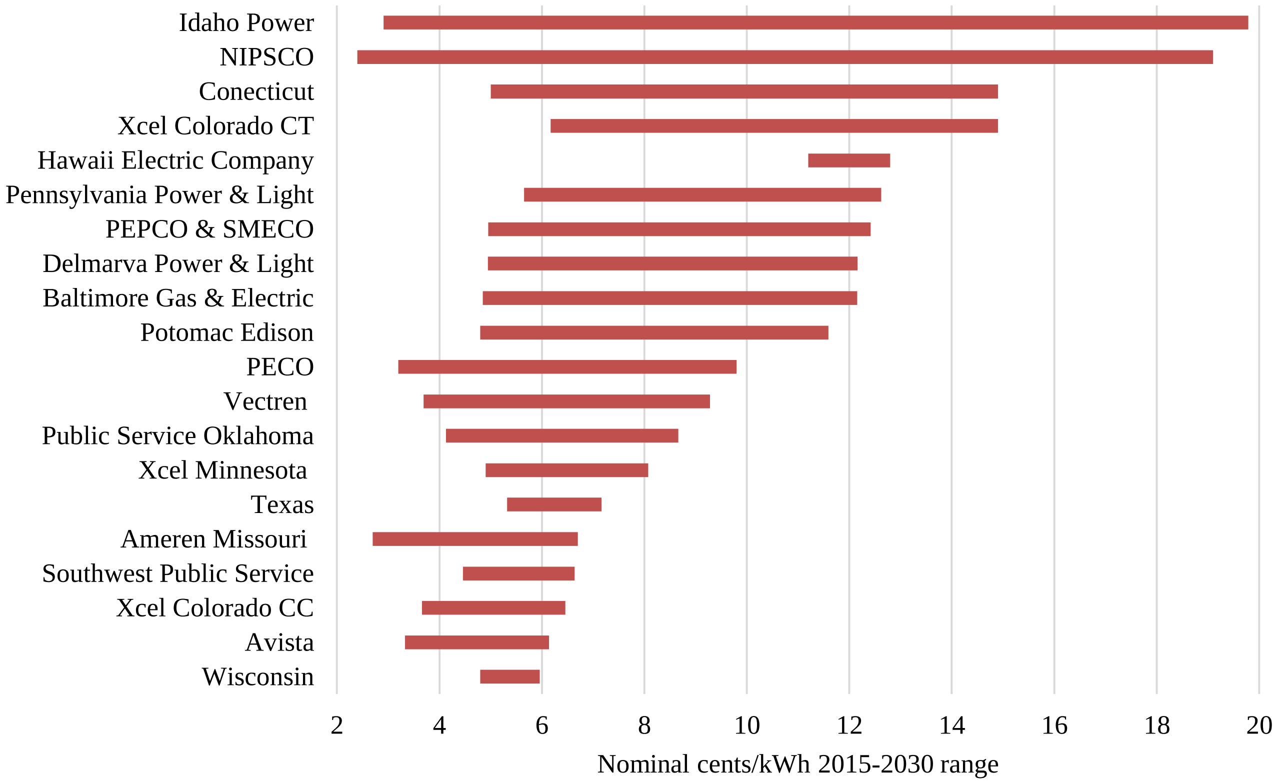

Figure 1. Avoided cost of energy 2015–2030 range for selected states and utilities in cents per kWh. We converted all real dollars to nominal dollars. If values were not clearly labeled, we assumed dollars were nominal.

Issues in Estimating Avoided Cost of Energy: Time, Natural Gas, and Line Losses

The cost of electricity varies throughout the day and year for both regulated and non-regulated utilities. As load grows, more expensive units are dispatched to meet demand. During peak demand hours, the most expensive units on a system will be dispatched to meet demand. While most states and utilities we reviewed differentiated avoided energy costs by time of day or year, many did not. Some simply averaged peak and nonpeak values to determine a single avoided cost.

Given historic volatility and variation among natural gas price forecasts, it can be difficult to use these forecasts when projecting avoided costs of electricity. In a 2010 paper, the National Regulatory Research Institute offered advice to regulators making planning decisions based on uncertain future natural gas prices (Costello 2010). The advice focused on two recommendations. First, regulators should require parties to submit a range of natural gas price forecasts instead of relying on a single best estimate. Second, regulators should require parties to forecast the risk associated with using the price forecasts. The quantification of risk between different forecasts can allow decision makers the opportunity to evaluate the differences under various natural gas price forecasts.

Avoided line losses are valued a number of different ways but are typically expressed as average line losses for either transmission or distribution, or both. Some utilities also calculate different line loss values for different customer classes. In our review of avoided cost methodologies, avoided line losses ranged from approximately 2% to 10%. While we found some utilities using marginal line losses, many used average line losses. As presented in a 2011 RAP report, using average line losses in calculating benefits of energy efficiency understates potential benefits of savings. According to the authors, because line losses are exponentially related to load, marginal line losses are greater than average losses, and line losses avoided by efficiency programs are more likely to occur during peak times. The difference between marginal and average line losses can be substantial and change throughout the day depending on load shape. Finally, line losses increase exponentially with load. Therefore, during the highest peak demand, losses are also at the highest point (Lazar 2011).

Avoided Cost of Generating Capacity

To determine avoided cost of capacity, the program administrator must determine what capacity is actually being avoided by the implementation of energy efficiency programs. Avoided capacity generally falls into three categories: avoiding the construction of a new asset, the purchase of an existing asset, or market purchases for capacity. The following sections explain in greater detail the differences between the three types of avoided capacity. Within the three types, there is variation in long-term and short-term avoided capacity. For example, in the short term, a utility may decide to purchase an existing asset because of the time needed to construct a new asset. But in the long term, a company may decide to build an asset.

The construction cost of a new power plant is the primary method of determining avoided capacity cost for utilities in jurisdictions not participating in wholesale capacity markets. As energy efficiency is expected to occur at the margin, the marginal generation resource is assumed to be the avoided capacity needed. Many utilities assumed a conventional combustion turbine would be the marginal unit needed to meet peak demand. However combustion turbines operate a limited number of hours per year and in many cases, a combined cycle unit is the marginal unit. Others may use the cost of implementing a demand response program as the cost of capacity for short-duration loads. Recent capital cost estimates for new combined cycle and combustion turbine power plants generally have fallen in the range of $950/kW to $1300/kW (SNL 2015). The U.S. Energy Information Adminstration estimates the cost between $900/kW and $1000/kW (EIA 2013). Other estimates we reviewed listed gas peaking plant total capital costs between $800 and $1,000 per installed kW and gas combined cycle between $1,006 and $1,318 per installed kW (Lazard 2014).

In the northeastern United States (and parts of the Midwest), generating capacity is procured through organized capacity markets. Estimating the avoided cost of capacity in a market environment is very difficult. There are numerous factors impacting the market price for capacity. A review of capacity market results in regional transmission operators (RTO) PJM, Independent System Operator New England, and New York Independent System Operator from 2006 to present shows wide variation year to year in capacity markets. Figure 2 shows some of the variability. This variation year to year does not generally show a linear trend of capacity prices, which would lend itself to a simple escalation factor for future prices. Instead, future prices must be modeled based on a number of factors regarding future likely scenarios for transmission builds, generation retirements, generation new builds, and fuel prices.

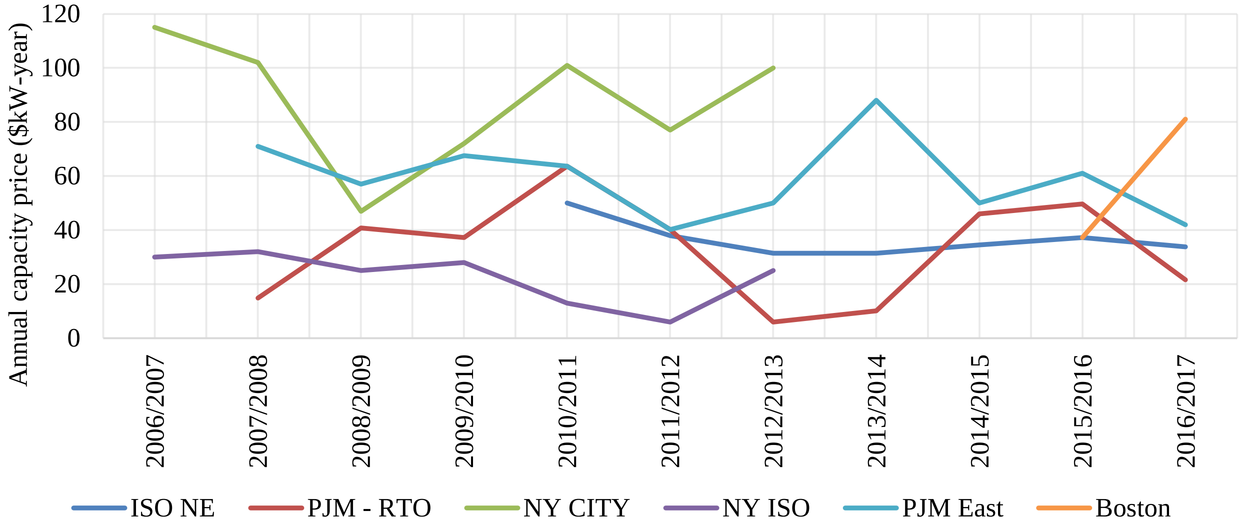

Figure 2. Capacity clearing prices in each RTO and select sub regions for commitment periods 2006–2017. *Source:* FERC 2013.

The purchase of existing market assets is also an option for some utilities. Existing generation may be less costly than a new build. For example, Dynegy Inc. recently acquired several existing power plants in the Midwest and New England. The Midwest plants were acquired for approximately $450 per kW, and the New England plants were acquired for $575 per kW (Qureshi 2014).[1] However a unit that has operated for many years has a shorter remaining life, and the annualized cost of capacity must take this into account. In another example of a higher-cost unit, the Fox Energy Center, a combined cycle unit in Wisconsin, was recently acquired by Wisconsin Public Service Corp for $741 per kW (Qureshi 2013).

Rise in Utility Generation Construction Costs

The Handy-Whitman Index of Public Utility Construction Costs is an annually published index for trends in utility construction costs. The index is designed to collect publicly available data reported to the Federal Energy Regulatory Commission to be a reasonably accurate measure of the cost of reproducing actual plant. The index is widely used by regulatory bodies, valuation experts, and regional transmission organizations to estimate trends in construction cost. To demonstrate the increase in utility construction costs in recent years, figure 3 graphs the index since 1991 for total steam production plant and gas turbo generators. These two categories represent the likely construction cost

1 The Midwest purchase included 11 power plants, of which 55% of capacity was natural gas fired and 45% was coal fired. The New England acquisition included 10 power plants, of which 58% of capacity was natural gas fired and 42% was coal fired. This transaction is currently awaiting final approval from the Federal Energy Regulatory Commission.

trends for an asset that would be avoided. We have also included the GDP deflator to show how these construction cost trends have compared with general inflation trends in the same time period. Figure 3 shows a significant upward trend in utility construction costs since 1991, with a large increase since 2003. The growth rate in construction costs for natural gas turbo generators experienced much higher growth rates than inflation.

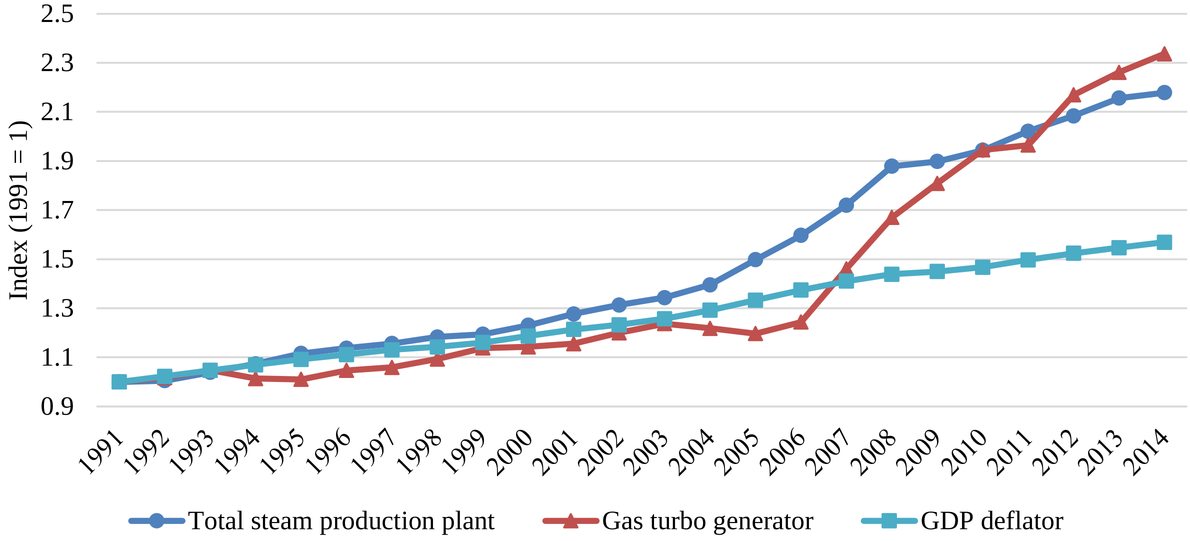

Figure 3. National average of generation construction cost indices. *Source:* Handy-Whitman 2014; BEA 2015.

Range of Avoided Capacity Cost

We collected avoided cost of capacity data for 17 states or utilities (some jurisdictions, such as Texas, assume a statewide value). Figure 4 shows the results for the avoided cost of capacity data collected.

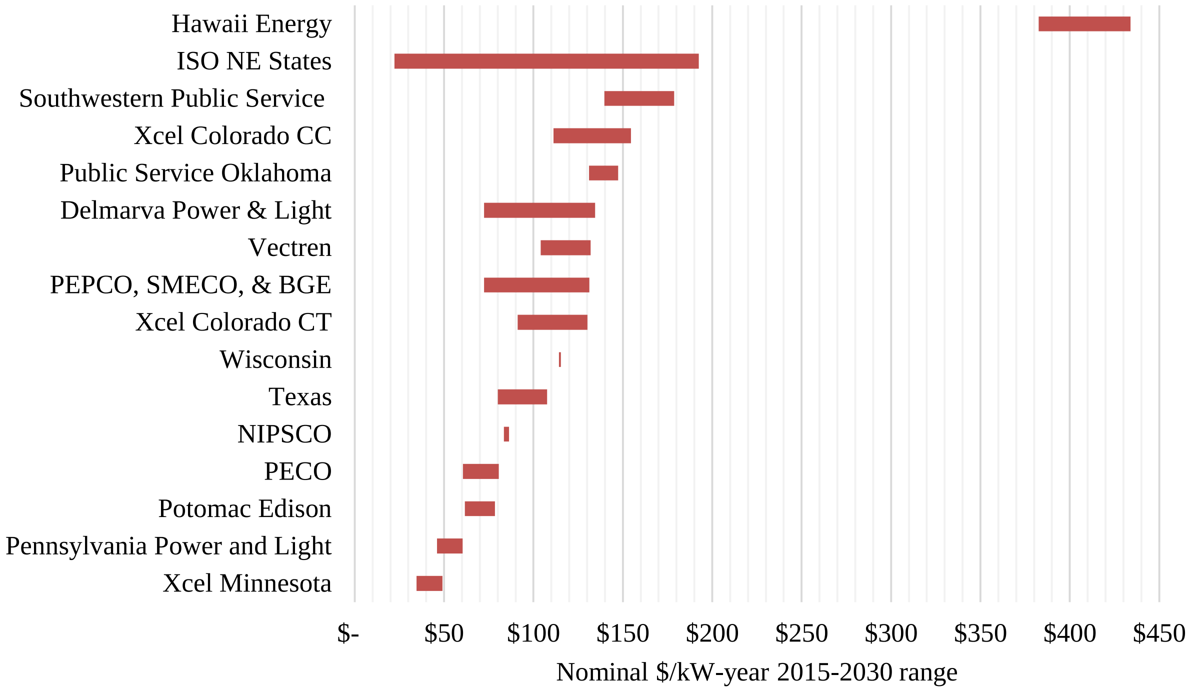

Figure 4. Avoided cost of capacity value range 2015–2030 for selected utilities and states.

Avoided Cost of Transmission and Distribution Capacity

Energy efficiency programs have the ability to reduce load in given areas for a utility system. Load reductions may reduce utility investments in T&D facilities over time as upgrades, maintenance, and new construction can be delayed or completely avoided. Avoided T&D costs are important when assessing the benefits of energy efficiency, as the economic value of these benefits can be substantial and are enjoyed by all ratepayers in a utility system, not just those who participate in programs.

In 2012 the Regulatory Assistance Project (RAP) published a paper on energy efficiency as a T&D resource (Neme 2012). The paper differentiated between active and passive deferrals of T&D investments due to energy efficiency. Passive deferral describes the deferral of T&D investments due to system-wide efficiency investments. RAP notes that passive deferrals are sometimes reflected in the avoided cost of T&D in efficiency program screening. Active deferrals refer to targeted investment of energy efficiency to defer or avoid building specific T&D facilities. The authors also highlighted the many instances in which energy efficiency programs allowed utilities to defer or completely avoid new T&D investments. In a notable example of a passive deferral, ComEd was able to reduce its projected T&D capital expenditures by nearly $1 billion after adjusting load forecasts to consider the impacts of system-wide energy efficiency efforts. The report also provides many examples of avoided T&D investments due to geographically targeted energy efficiency efforts.

A 2014 survey of methodologies used to estimate avoided T&D conducted by the Mendota Group on behalf of Xcel energy reveals the wide variation among utilities in making the calculation (Mendota 2014). While there was some commonality, significant differences in methodological approach are apparent. The study concludes there may not be a best practice method to determine avoided cost of T&D because many different methods may be capable of producing a valid estimate. The calculation of avoided T&D benefits is dependent on location, system-wide impacts, and time of day or year. Estimation of these costs requires complex system modeling. The study also notes while energy efficiency has the ability to defer or avoid T&D investments, the measures must be coincident with system peaks to achieve this purpose.

The Mendota report also collected data for 36 companies estimating avoided T&D benefits over the last three years. The estimates span most regions of the country except the southwest. The range of the avoided distribution was found to be $0 to $171/kW-year with an average avoided cost of $48.37. The range of the avoided transmission cost was found to be $0 to $88.64/kW-year with an average avoided cost of $21.21. Most avoided T&D cost estimates were between $40 and $60/kw-year with four companies assuming $0/kw-year.

Range of Avoided Cost of T&D

We collected 45 data points for estimates of avoided T&D used in efficiency program screening. Most estimates of avoided T&D were presented as a single or levelized value. Figure 5 displays the wide range of estimates for this benefit ranging from $0/kW-year to $200/kW-year. Of the 45 data points, 6 were $0/kW-year, meaning avoided T&D benefits were excluded from program screening. The majority of values were between $25 and $50 per kW-year. Of the estimates reviewed for this study, the highest level of avoided cost of T&D was reported in the northeastern region.

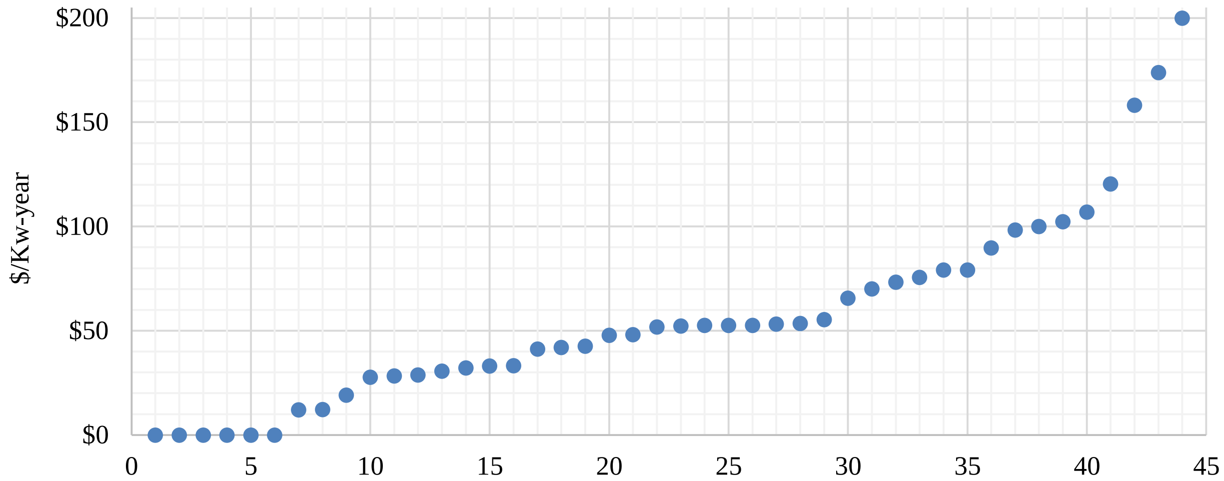

Figure 5. Survey of avoided cost of T&D values. Each point in the graph represents the avoided cost of T&D for a specific company or utility.

Avoided Cost of Ancillary Services

Ancillary services are defined as the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operations of a transmission system (PJM 2015). Ancillary services include reactive power and voltage support, spinning reserves, supplemental reserves, generator imbalance, energy imbalance, regulation and frequency response, and schedule, system control, and dispatch (FERC 2007). Energy efficiency, especially programs reducing peak load, have the ability to reduce the demand for ancillary services. The cost of ancillary services is traditionally collected in transmission rates but includes costs associated with generating capacity, energy, and transmission costs. In our limited review, we found jurisdictions that included avoided ancillary service costs in avoided cost of capacity, energy, and T&D.

Avoided Cost of Environmental Compliance

Power plants in the United States face environmental regulations from state and federal agencies. Examples of air emissions that are regulated include mercury, sulfur dioxide, nitrogen oxide, particulate matter, and ozone. The compliance costs for some of these rules can be substantial and have contributed to decisions to retire older coal-fired power plants. Energy efficiency has the ability to reduce power plant emissions by reducing electricity generation. Reduced emissions can translate into reduced compliance costs, a utility system benefit of energy efficiency. Quantifying this benefit can be difficult as compliance costs can be borne through emissions allowances, capital costs for new pollution-control equipment, and increased operating costs to sustain pollution control equipment. A recent report from the Regulatory Assistance Project notes it is important to consider most of these costs are internalized in market prices in long-run forecasts and should be handled carefully in avoided cost methodologies to avoid double-counting of benefits (Lazar 2013).

Utility efforts to estimate the cost of future environmental compliance has been largely focused on the forecasted avoided cost of carbon dioxide emissions and the avoided cost of compliance for the Cross State Air Pollution Rule. As with most avoided cost calculations, companies operating in wholesale market environments utilize different methodologies than traditional vertically integrated companies. In both instances, the avoided cost of compliance with future environmental regulations was usually embedded in the avoided energy costs.

In companies operating in wholesale markets, assumptions on future costs of emissions was usually included in economic simulations to determine wholesale market prices. Therefore, the wholesale market prices produced by these models included the avoided cost of environmental compliance for CO_2, NO_x, and SO_2. Assumptions on future prices of emissions varied and were not uniform among studies we reviewed. For vertically integrated companies, the most common methodology in our review was an assumption of carbon dioxide in dollars per ton to begin in a specific year. Many states and companies we reviewed used a similar methodology with varying assumptions on cost and start date of cost of compliance.

Demand Reduction Induced Price Effects

Energy efficiency programs also have the ability to reduce wholesale market prices for energy, capacity, and natural gas. When load is reduced in a jurisdiction operating in a wholesale market environment, demand for energy or capacity is also reduced, resulting in price suppression in the associated market. This concept is known as market price mitigation, price suppression, or demand reduction induced price effects (DRIPE). DRIPE benefits can be substantial, and inclusion of these benefits in program cost screening can increase the cost effectiveness of peak-focused programs by up to 15–20% (Synapse 2008). Also, like other utility system benefits, DRIPE benefits accrue to both participants and nonparticipants of utility-sponsored energy efficiency programs.

Currently, electric utilities in 15 states and the District of Columbia operate in competitive wholesale energy markets and rely on market purchases to meet retail customer demand.[2] The total population in these 16 jurisdictions represents nearly half of the total population of the United States. As of late 2014, 6 of the 16 jurisdictions calculate DRIPE benefits and include these benefits in cost-effectiveness screening for programs (Massachusetts, Rhode Island, Vermont, Connecticut, Delaware, Maryland, and District of Columbia). Of the remaining 10 states, 9 do not include any DRIPE benefits in cost-effectiveness screening.

The level of benefits passed on to retail customers from load-serving entities operating in

2 There are other states operating in competitive wholesale markets, but they are not unbundled retail choice states. For a utility to calculate DRIPE benefits, it would need to rely on market purchases to enjoy the benefits of reduced wholesale market energy prices. Therefore, utilities in states like Indiana, which serve retail load with self-scheduled generation resources, would not receive DRIPE benefits from energy efficiency.

wholesale energy markets is dependent on several factors, including wholesale power contracts, retail rate-making structures, and energy procurement processes. Wholesale power contracts can require load-serving entities to pay fixed prices for energy for years at a time without change. Retail rate-making structures often insulate retail customers from large swings in market prices to avoid rate shocks. Finally, energy procurement plans, like those filed in Maryland and Illinois, require utilities to hedge against real-time market prices by entering into fixed-price contracts for short periods of time. Because of this process, retail customers may not see the benefits of DRIPE in rates for at least a year or two. DRIPE benefits can also benefit retail customers in regulated states, to the extent the utilities in these states rely on wholesale energy markets to meet demand. These costs are often collected in fuel-adjustment clauses or regional-transmission organization bill riders.

Methodologies to Calculate DRIPE Benefits

There are very few published methods to calculate DRIPE benefits. The 2013 Avoided Energy Supply Costs in New Englad report relied on statistical methods at the state level based on various factors to determine energy DRIPE coefficients (AESC 2013). This approach allowed the application of a single coefficient as prices change. In Maryland, to determine future DRIPE benefits, market simulation models were used to forecast future energy and capacity values in specific zones located within regional transmission organizations (Exeter 2014). The simulations are conducted with and without energy efficiency to determine the difference in prices. The price difference in the zone is then adjusted to focus on the price difference in a specific utility territory. Statewide price impacts are also determined. One problem with this approach is it does not fully account for imports and exports, which can greatly impact prices.

Utility Nonenergy Benefits

Nonenergy benefits (NEBs), also known as nonenergy impacts (NEIs) or other program impacts (OPIs), are the benefits of energy efficiency programs not directly related to energy. Significant study and attention has been given to the societal NEBs provided by energy efficiency programs. These benefits include improved comfort, reduced illnesses and deaths from power plant emissions, improved productivity, and many others. In addition, NEBs also accrue to utilities directly in the implementation of energy efficiency programs. These benefits typically include reduced costs associated with service interruptions as low-income customers' reduced utility bills result in fewer situations of nonpayment of an electricity bill. Other utility sector NEBs from utility programs include reduced carrying costs associated with reduced arrearages and longer T&D component life due to lighter loading. Most utility NEBs are associated with low-income programs. Reduced costs of service interruptions and carrying costs for arrearages are both benefits realized through the implementation of low-income programs.

Very few jurisdictions or states in our review included utility-specific NEBs in program screening. According to our review of existing literature, only Rhode Island, New York, and Massachusetts explicitly calculate utility-specific NEBs (Woolf 2013). Several other states use an adder approach that included NEBs without explicitly quantifying them. The adder is generally between 10 and 15% of avoided cost of energy estimates. This approach adds a fixed percentage of total benefits to assume NEBs. However it is not clear if utility-specific NEBs are considered to be included in the added benefits in this approach.

In Massachusetts, a 2011 statewide study has provided the basis for NEB estimations (NMR 2011). The study relied on thorough literature reviews, company data, and interviews to determine Massachusetts-specific utility NEBs. Almost all of the utility NEBs explored in this study were related to the implementation of low-income programs. The study recommended specific values per participant per year for several NEBs. Table 2 presents the recommended annual values in Massachusetts from the 2011 NMR study.

Table 2. Massachusetts utility NEB value recommendations ($/MWh)

NEB	Annual value
Arrearages	$2.61
Bad debt write-offs	$3.74
Terminations and reconnections	$0.43
Customer calls	$0.58
Collections notices	$0.34
Safety-related emergency calls	$8.43

Source: NMR 2011

Avoided Cost of Renewable Portfolio Standard Compliance

Thirty states and Washington, DC, mandate electric suppliers to obtain a certain percentage of generation from renewable sources. The renewable portfolio standard (RPS) policies differ from state to state. As energy efficiency programs reduce energy demand, the level of energy required from renewable resources in these states will also be reduced. This will allow utilities to avoid some of these costs associated with meeting the RPS goal. While this benefit was not common in our review of avoided costs used in program screening, some states did estimate the avoided cost of RPS compliance.

Avoided RPS compliance costs were included in a 2014 Maryland avoided cost study. The avoided cost was based on estimating the future prices of renewable energy credits (RECs) to Maryland utilities and then multiplying this price by the annual percentage requirement for each type of REC. RECs in Maryland are differentiated by the type of renewable generation. Solar RECs are of the highest value, and then Tier 1 followed by Tier 2. Each REC represents a MWh of renewable energy and ranged from $0.50 to $4.50 per MWh. Avoided costs of RPS compliance are also included in the New England Avoided Energy Supply Cost study. This study assumes full compliance with RPS standards for each load-serving entity in the study with compliance costs estimated between $0.50 and $10 per MWh.

Other Potential Benefits

This report is not an exhaustive list of the utility system benefits accruing from efficiency programs. We have attempted to capture different methodologies for the most prevalent benefits being used across the country. Aside from the traditional utility system benefits discussed above, other benefits include increased reliability, reduced levels of risk, and fuel price hedging. Most of the other potential benefits are focused on the reduction of utility risk. A recent report on the risks associated with various utility generation options cited energy efficiency as the option with the least risk (Ceres 2014). Very few companies include the benefits associated with reduced utility risk in cost-effectiveness screening. No states or companies we reviewed explicitly calculated this benefit. However some states have considered risk benefits when determining the nonenergy benefit adders and in determining discount rates used for program screening.

Increased Reliability

Energy efficiency savings reduce peak demands and the strain on the utility system during hours of peak demand. The reduced demand on the system can prevent rolling blackouts. While it can be very difficult to quantify the benefits of reliability, the economic costs of power outages, even ones lasting only hours, can be substantial. The 2003 blackout in the northeastern United States resulted in losses of approximately $6.4 billion (Anderson 2003). While this example is of an extreme event, it nonetheless demonstrates the significant economic losses occurring from blackouts. While any system resource could reduce demand to prevent blackouts, energy efficiency can often reduce peak demand at the lowest cost (Molina 2014). No companies or states we reviewed quantified this benefit for cost-effectiveness screening.

Reduced Utility Risk

Energy efficiency programs have the ability to reduce utility risks on several fronts. First, utility risk of construction cost overruns is reduced when new power plants are avoided or deferred. Construction cost overruns for new power plants are not uncommon. Construction cost overruns are also not uncommon in new transmission projects. Energy efficiency investments have the ability to reduce or eliminate this risk if construction projects are avoided or deferred.

Energy Efficiency as a Fuel-Price Hedging Strategy

To avoid the risks associated with exposure to fluctuations in fuel prices, many utilities engage in fuel-price hedging. There are many fuel-price-hedging strategies available to electric utilities. Companies can enter into short- and long-term fuel-price contracts to lock in prices. Companies can also engage directly in natural gas or coal extraction to mitigate market price risks. Energy efficiency can also act as a fuel-price hedge through reduced demand at a known cost.

Energy Efficiency as a Fuel-Supply Risk-Reduction Strategy

Increased energy efficiency has the ability to reduce the level of fuel necessary for a utility at a given time. A demand reduction during peak times reduces the fuel-supply risk some utilities face because of constrained natural gas pipeline capacity. Natural gas pipelines are especially constrained in the Northeast and have led to high wholesale spot prices in the region during high-demand days. For example, PJM experienced significant generator forced outages due to natural gas supply interruptions during the polar vortex of January 2015. Wholesale energy prices increased dramatically partly because of the fuel supply interruptions caused by extreme cold.

Conclusions

We are able to draw several conclusions following the collection and review of various state policies and utility practices in avoided cost assumptions and calculations. First, the methodological approach to calculating utility system benefits is diverse. In states lacking specific methodological approaches or even definitions, significant differences exist between utilities. These differences can cause problems with comparability of program results within a state or among utilities in different states. Differences in assumptions, methodologies, and benefits greatly impact the net present value of the benefits in cost-effectiveness testing. While we would expect each utility to differ in avoided cost values because of location, generation mix, and other factors, in order to accurately compare programmatic performance among utilities in a state or nationally, common avoided cost methodologies should be employed.

A second conclusion we draw from this research is that nonparticipants benefit substantially from energy efficiency programs. While nonparticipants do not receive the immediate benefit of a bill reduction like participants do from installing energy efficiency measures, nonparticipants receive the economic benefit of reduced rates in later years because of the decision to pursue the least-cost, least-risk resource of energy efficiency.

A final significant conclusion we draw from this research is that many utilities and states exclude critical, substantial benefits from cost-effectiveness screening of programs. Over the course of our review, we found many occasions in which substantial benefits, such as avoided T&D, DRIPE, and avoided RPS compliance, are not quantified as a benefit of efficiency programs. Exclusion of benefits will adversely affect the program screening process and will result in a utility pursuing higher-cost, less-efficient resources to meet customer demand. This will raise rates on all customers in a utility system.

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