

Financial Impacts of a Combined Energy Efficiency and Net-Metered PV Portfolio on a Prototypical Northeast Utility

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Acronyms and Abbreviations

AEV	aggressive EE and PV
BAU	business-as-usual
CAGR	compound annual growth rate
CapEx	capital expenditures
C&I	commercial and industrial
DER	distributed energy resource
DG	distributed generation
DOE	Department of Energy
EE	energy efficiency
FAC	fuel adjustment clause
FINDER	FINancial impacts of Distributed Energy Resources
GRC	general rate case
ISO-NE	ISO New England
LBNL	Lawrence Berkeley National Laboratory
NAPEE	National Action Plan for Energy Efficiency
NE	northeast
NEM	net-energy metering
O&M	operations and maintenance
PUC	public utilities commission
PV	photovoltaic
ROE	return on equity
RPC	revenue-per-customer
RPS	renewable portfolio standard
T&D	transmission and distribution

Executive Summary

Reductions in electricity consumption from customer-funded energy efficiency (EE) programs and distributed photovoltaic (PV) are expected to dramatically increase over the next ten years. While EE programs and net-metered PV provide numerous utility, customer, and societal benefits, including utility cost reductions, lower customer bills, and achievement of clean energy public policy goals, they may contribute to stagnant or declining retail sales for electric utilities. Investor-owned utilities are concerned about stagnant or declining sales as they undermine existing regulatory and ratemaking approaches to cover fixed costs and may negatively impact utility profitability. Current retail rate designs allocate a large fraction of fixed costs to volumetric energy charges creating challenges for the utility's recovery of its fixed costs due to reductions in retail sales between rate cases.

Regulators and policymakers are interested in pursuing policies and strategies that don't undermine the utility's financial viability in the pursuit of public policy goals. Many statesⁱ are considering incremental changes to rate-of-return regulation to provide explicit incentives for successful achievement of EE savings goals, support of distributed energy resources, and better alignment of utility costs with revenue collection.

This report quantifies the combined financial impacts of EE and distributed PV on utilities and ratepayers, by building upon prior Lawrence Berkeley National Laboratory (LBNL) studiesⁱⁱ in four distinct ways. First, prior LBNL research has looked at the impact of EE and PV in isolation. This is the first effort to jointly assess the impacts of EE and PV. Second, the EE savings and PV penetration levels assumed in the study, though grounded in existing policies and forecasted PV adoption, are an upper-bound of sales and peak demand reductions representing an aggressive implementation and deployment scenario.ⁱⁱⁱ Third, the study models the hourly impacts of EE and PV on utility load and its subsequent reduction in utility costs depending on the timing and coincidence of the EE and PV savings. This represents a more granular modeling of the relationship between impacts of EE and PV on utility load and costs, and how that relationship changes at increasing EE and PV penetration. Fourth, the study relies on a more precise modeling of utility ratemaking, including customer class-level cost allocations, and the relationship between changes in customer class energy and peak demand, utility costs, and future rates.

ⁱ NCCETC (2016) counted 39 states considering changes to net metering compensation mechanisms, retail rate designs, or solar ownership structures during the first quarter of 2016.

ⁱⁱ See (Cappers and Goldman, 2009a; Cappers et al., 2009; Cappers et al., 2010; Satchwell et al., 2011; Satchwell et al., 2014).

ⁱⁱⁱ We characterize an aggressive scenario resulting in significant sales and peak demand reductions due to installation of efficiency measures and distributed PV systems; however this does not represent "load defection" or "grid defection" scenario. The terms "load defection" and "grid defection" have typically been used to describe the ability for customers to use distributed PV and electric storage systems to self-generate and disconnect from their electric delivery utility (RMI, 2014, 2015). From the utility's perspective, the implications of "load defection," "grid defection," and our aggressive scenario purely on the utility's loss of future retail electric sales are somewhat synonymous. However, customers in our aggressive EE and PV penetration scenario remain connected to the electric delivery utility's system because we don't assume that cost-effective, mass-market electric storage systems will be prevalent in the near term.

Specifically, we quantify the shareholder and ratepayer impacts for a northeastern, distribution-only utility (“NE utility”) that achieves aggressive EE savings and PV penetration levels (i.e., AEV scenario) compared to a Business-As-Usual (BAU) future. We also consider several ratemaking and regulatory mechanisms which have historically been used to address potential misalignments between utility profit achievement and motivation to pursue customer-funded EE programs (Satchwell and Cappers, 2015). These mechanisms may also be effective at mitigating similar misalignments with distributed PV. Specifically, in the AEV scenario, we model revenue decoupling; rate designs that collect a greater share of non-fuel costs via demand or customer charges (as opposed to volumetric charges); and targeted shareholder incentive mechanisms.

Key results of the analysis include:

- The aggressive EE and PV portfolios produce significant declines in the NE utility’s forecasted retail sales and peak demand. Retail electricity sales decline at -3.7% per year and peak demand declines at -0.1% per year during the ten year period that EE savings and PV installations ramp-up (2017-2026), compared to load growth absent EE and PV. Because the EE savings targets and PV penetration levels are specified in terms of a percent reduction of retail sales, they each reduce NE utility sales on a one-for-one basis. The peak demand impacts of EE and PV depend on the timing and coincidence of the EE and PV portfolios relative to the utility’s annual peak demand.
- In the aggressive EE/PV scenario, NE utility costs decrease by 3% (\$1.1B on a 20-year present-value basis at 7% nominal discount rate) compared to a business-as-usual (BAU) scenario given the modeled relationships between utility sales, peak demand, and the utility’s fixed and variable costs. Virtually all of the cost reductions (99%) are attributable to reduced costs of purchased power.
- In aggregate, utility collected revenues (i.e., total customer bills) decrease by \$1.7B (5%) compared to the BAU case (see red bar for Collected Revenues in bottom-left Figure ES- 1).

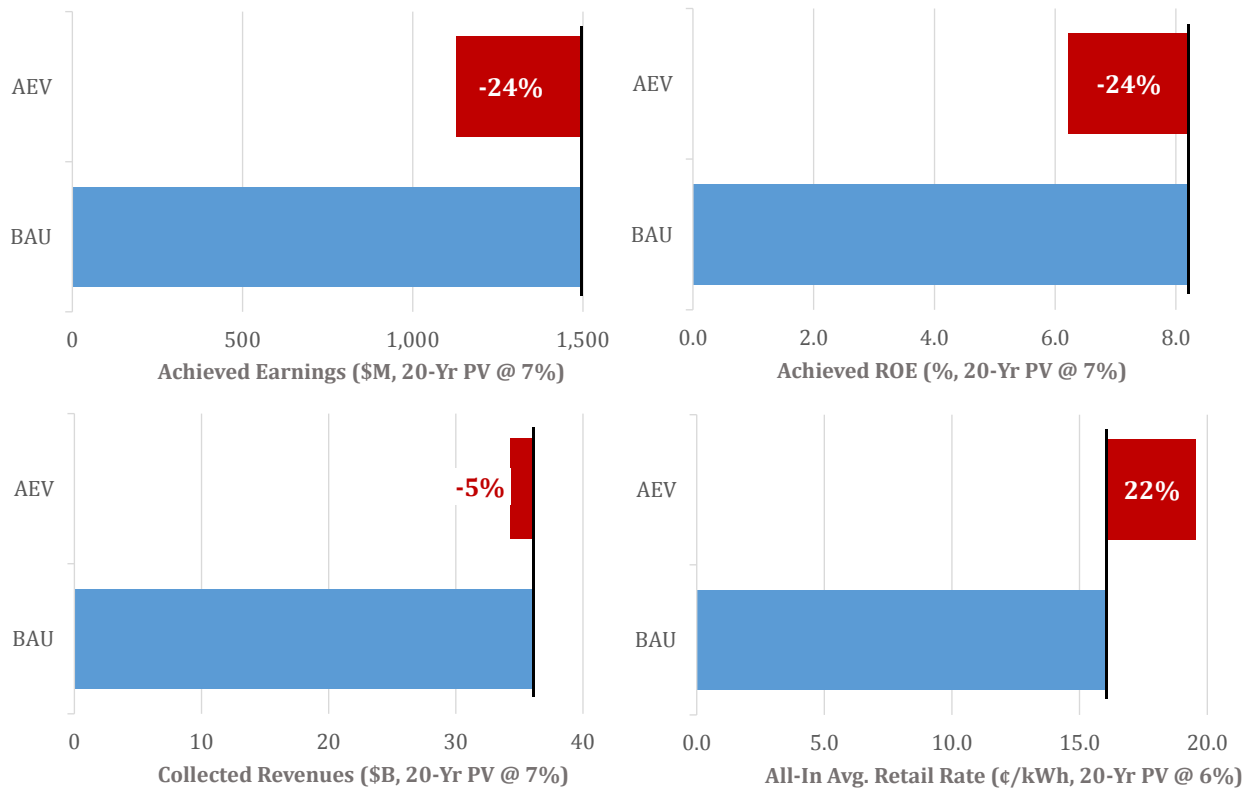


Figure ES- 1. Financial impacts of aggressive EE/PV portfolio (AEV) on NE utility earnings, ROE, collected revenues and all-in average retail rate

- From the NE utility shareholder’s perspective, the aggressive EE and PV portfolio results in a significant decline in achieved after-tax ROE and earnings. After-tax earnings achieved by the NE utility are \$364M lower (24%) and the NE utility’s average achieved ROE is 200 basis points lower (24%) in the aggressive EE/PV scenario compared to the BAU scenario over the 20-year analysis period (see red bar for Achieved Earnings and ROE in top-left and top-right Figure ES- 1).
- All-in average retail rates for the NE utility in the aggressive EE/PV scenario are 3.5 cents/kWh higher (22%) over 20 years than in the BAU scenario (see Figure ES- 1) or about 3% higher each year. This significant increase in average all-in retail rates is driven by several factors: (1) the utility’s revenues decrease more than their costs because the combined EE and PV portfolio reduces only a small portion of the utility’s non-fuel costs and (2) the utility’s remaining costs must be spread over significantly lower retail sales.
- These changes to ratemaking and alternative regulatory approaches are able to mitigate some or all of the negative financial impacts to utility shareholders that occur in the AEV scenario (see Figure ES- 2). Specifically, revenue-per-customer (RPC) decoupling, a significantly increased fixed customer charge, and a residential demand charge and increased commercial and industrial (C&I) customer demand charge all provide NE utility shareholders with additional revenues (\$803M or 2.2% of BAU revenues, \$568M or 1.6% of BAU revenues, and \$206M or 0.6% of BAU revenues, respectively) that restore some or all

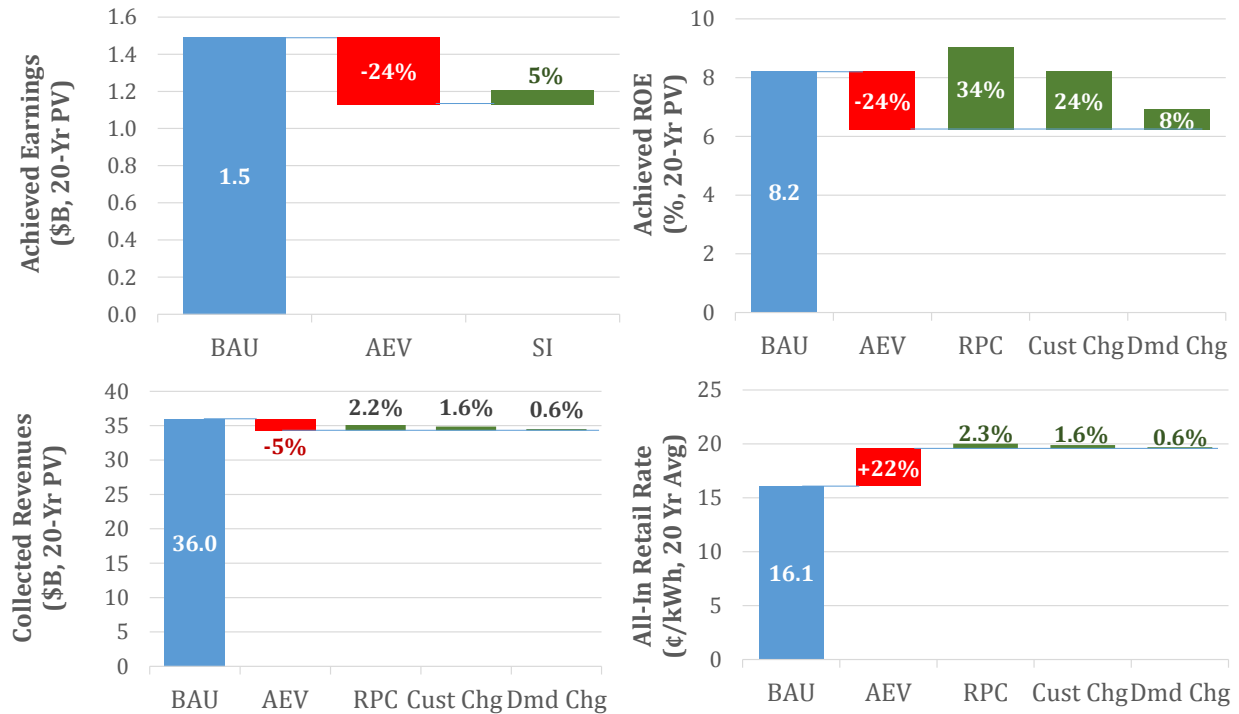
of the reductions in the achieved after-tax ROE of the NE utility (282 basis points, 200 basis points, and 69 basis points, respectively). Importantly, the RPC decoupling provides more than sufficient revenues to compensate the utility for revenue erosion in the AEV scenario. Moreover, the RPC decoupling mechanism does not alter retail rate design and therefore does not change customer economics in the same way as a demand or customer charge rate design. The demand charge and customer charge mitigation approaches modeled in this study shift revenue collection away from volumetric energy to a greater extent than utilities have proposed to date;^{iv} our results suggest that these ratemaking strategies have the potential to mitigate much of the earnings erosion that occurs in the AEV scenario.

- We also considered a targeted shareholder incentive in which the utility receives a portion (10%) of administered EE program budgets and capitalizes a portion (10%) of distributed PV systems (i.e., partial utility ownership of PV). This strategy provides additional shareholder returns (\$81M) that further mitigate the negative financial impacts on the utility that occur in the aggressive EE/PV scenario.
- Importantly, these mitigation measures further increase average all-in retail rates in the Aggressive EE/PV scenario by 0.1 to 0.5 cents/kWh (or 0.6% to 2.3%, respectively) in addition to the 3.5 cents/kWh increase in average all-in retail rates prior to the addition of mitigation measures.^v
- We also estimated bill impacts on participating and non-participating customers using illustrative EE program types and PV investments. Among those customers who never install EE measures or PV systems (i.e., non-participants), bills increase in the AEV scenario. For those customers that invested in energy efficiency measures in a utility program or invested in PV (i.e., participants), the magnitude of bill savings depends on the timing of that investment. The magnitude of bill savings also varies significantly depending on the particular EE program type or PV investment. For example, customers who invest in EE measures that produce modest energy savings (e.g., residential product rebate and low income programs) see higher bills over the 10 year analysis period since their savings are not large enough to offset the rising rates. Conversely, residential customers that invested in PV see lower bills during the entirety of the analysis period. Also, residential customers in a whole home retrofit program and C&I customers that invest in PV achieve lower bills during most of the analysis period.
- We also explored the change in participant and non-participant customer bills in the demand charge mitigation case and found that a demand charge does not increase non-participant customer bills and only modestly increases EE customer bills. However, such a change in rate design dramatically reduces the bill savings (i.e., increases customer bills)

^{iv} We increased the share of non-fuel costs collected via a customer charge from 18% to 75% for the residential customer class and from 11% to 75% for the C&I class and for a demand charge from 0% to 50% for the residential class and from 47% to 75% for the C&I class. Such changes in retail rate design are intended to be illustrative and not suggestive of what is reasonable or appropriate.

^v We do not present quantitative results for changes in average retail rates with the shareholder incentive mechanism. Qualitatively, we know that any increase in achieved earnings associated with a shareholder incentive mechanism will by definition result in an increase in average retail rates relative to the AEV scenario, all else being equal. Such an increase in average retail rates would most likely be related to the EE shareholder incentive as any additional costs from the utility PV ownership would be passed through to the PV customers only.

for PV customers because of the way that PV systems produce highly asymmetric reductions in energy and demand.



RPC - revenue-per-customer decoupling
 CustChg - increased customer charge
 Dmd Chg - residential demand charge and increased C&I demand charge
 SI - targeted shareholder incentives

Figure ES- 2. Efficacy of alternative ratemaking, revenue collection, and targeted incentive mechanisms to mitigate adverse financial impacts on utility shareholders

We draw several high-level policy implications from the study results. First, the financial impacts at the utility level and across all customer classes are directionally consistent with prior LBNL studies that looked at EE or PV in isolation, though the impacts are much greater in magnitude due to the combined effects of the more aggressive EE and PV savings. The significantly larger shareholder and ratepayer impacts primarily reflect how the aggressive EE and PV savings levels reduce utility revenues by a much greater amount than utility costs.

Second, the precise impacts of EE and PV on future utility load and cost growth depend upon numerous specifics about utility physical, financial, and operating characteristics and assumptions about the deferral value of EE and PV (e.g., capacity value, avoided transmission and distribution cost value). Our analysis relied on several assumptions about the timing of EE and PV load reductions relative to total utility load and the ability of EE and PV savings to defer a portion of growth-related non-fuel utility costs. There are numerous studies suggesting a wide range of possible avoided cost values for EE and PV.^{vi} Moreover, a prior LBNL study showed that financial impacts of net-metered PV are particularly sensitive to different assumptions about the value of PV

^{vi} See, for example, a meta-analysis of the value of PV in Hansen et al., 2013.

(Satchwell et al., 2014). Strategies to maximize the avoided costs of EE and PV could potentially mitigate rate impacts by producing greater cost reductions. Such strategies might include directing or incentivizing deployment of EE and PV through integrated distribution system planning or geographically targeted incentive structures and designing EE or demand response programs to focus on peak demand periods that drive many utility non-fuel costs.

Third, our analysis shows that a variety of approaches that constitute arguably “incremental” changes to utility business or regulatory models could be deployed to mitigate impacts on utility shareholders in a future pathway that includes aggressive efficiency savings and customer-sited PV deployment. The analysis of mitigation measures supports prior findings that ratemaking and incentive design matters. Mechanisms intended to mitigate the revenue erosion effect differ greatly in their design by either shifting utility revenue collection away from volumetric retail sales to customer counts or customer demand. Importantly, RPC decoupling can offset earnings erosion and do so in a way that does not directly impact the underlying customer economics.

Finally, these mitigation approaches may entail substantive tradeoffs. For example, decoupling and other mitigation strategies that involve changes to the way that the utility collects revenue may lead to increases in average retail rates. Important tradeoffs may also exist among competing policy and regulatory objectives. For example, rate designs that collect a greater portion of utility costs via fixed charges may better align utility fixed costs and revenue collection but may also negatively impact the economics and customer adoption of EE and DG by increasing payback times. Given the complex set of issues involved in implementing many of the possible mitigation measures, regulators may wish to address concerns about the ratepayer and shareholder impacts of EE and distributed PV within the context of broader policy- and rate-making processes.

1 Introduction

Customer-funded energy efficiency (EE) spending in the United States almost tripled from 2007 to 2014 (CEE, 2016; CEE, 2008) and EE programs in 16 states each generated more than a 1.0% annual reduction in utility sales in 2015 (Gilleo et al., 2015).¹ These savings levels will likely increase with spending on EE programs projected to double again from 2010 levels by 2025 (Barbose et al., 2013). Similarly, though at a smaller scale,² distributed photovoltaic (PV) penetration is projected to reach 2.9% of U.S. retail electric sales in 2020 with several states expected to see penetration rates in excess of 5% (GTM and SEIA, 2015). Many of the states with greater EE savings levels (i.e., greater than 1.5% per year) are also expected to see higher PV penetrations. While EE programs and net-metered PV provide numerous utility, customer, and societal benefits, including utility cost reductions, lower customer bills, and achievement of clean energy public policy goals, they also contribute to potential stagnant or declining retail sales for electric utilities.

Investor-owned utilities are concerned about stagnant or declining sales as they undermine existing regulatory and ratemaking approaches to cover fixed costs and may negatively impact utility profitability. Current retail rate designs allocate a large fraction of fixed costs to volumetric energy charges. This creates challenges for the utility's recovery of its fixed costs due to reductions in retail sales. Under traditional cost of service regulation, most utilities are not financially motivated to support aggressive EE savings goals and distributed generation (DG) enabling policies.

Regulators and policymakers are interested in policies and strategies that align public policy goals while maintaining the utility's financial viability. Most states are considering incremental changes to rate-of-return regulation to provide explicit incentives for successful achievement of EE savings goals, support of distributed energy resources, and better alignment of utility costs with revenue collection (Stanton, 2015).

There has been extensive work recognizing and describing the lack of a utility financial incentive to pursue energy efficiency under existing rate-of-return regulatory models (e.g., Moskovitz, 1989; Eto et al., 1994; Moskovitz et al., 2000; NAPEE, 2007) and more recent conceptual work regarding similar misalignments between utility profit motivations and distributed energy resources (e.g., Moskovitz et al., 2000; Kind, 2013; Graffy and Kihm, 2014). There has been limited work to date quantifying the financial implications of EE and PV for utility shareholders and customers that takes into account impacts on utility costs and revenues within the existing regulatory approaches. Lawrence Berkeley National Laboratory (LBNL) has published several quantitative analyses (e.g.,

¹ CEE reported electric and gas utility budgets of \$2.6B for energy efficiency in 2007 and \$6.9B in spending in 2014. We exclude load management/demand response program spending.

² Barbose et al., (2016) estimated the cumulative impacts of EE to be 15 times greater than the cumulative impacts of distributed PV through 2014.

Cappers and Goldman, 2009a; Cappers et al., 2009; Satchwell et al., 2011; Satchwell et al., 2014) quantifying the financial impacts of EE and distributed PV on utility shareholders and ratepayers, in isolation. However, many states with the highest level of savings from EE programs also have high PV penetration levels. Four of the top-ten ranked states for energy efficiency (CA, MD, NY, and MA) have PV penetrations that are well above the national average (Gilleo et al., 2015; GTM and SEIA, 2015).³

This report quantifies the combined financial impacts of EE and distributed PV on utilities and ratepayers, by building upon prior Lawrence Berkeley National Laboratory (LBNL) studies⁴ in four distinct ways. First, prior LBNL research has looked at the impact of EE and PV in isolation. This is the first effort to jointly assess the impacts of EE and PV. Second, the EE savings and PV penetration levels assumed in the study, though grounded in existing policies and forecasted PV adoption, are an upper-bound of sales and peak demand reductions representing an aggressive implementation and deployment scenario.⁵ Third, the study models the hourly impacts of EE and PV installations on utility load and its subsequent reduction in utility costs depending on the timing and coincidence of the EE and PV savings. This represents a more granular modeling of the relationship between impacts of EE and PV on utility load and costs, and how that relationship changes with increasing penetration of EE and PV. Fourth, the study relies on a more precise modeling of utility ratemaking, including customer class-level cost allocations, and the relationship between changes in customer class energy and peak demand, utility costs, and future rates.

We quantify the shareholder and ratepayer impacts for a northeastern, distribution-only utility that achieves aggressive EE savings and PV penetration levels over the next 10 years as compared to a business-as-usual (BAU) future. Historically, the northeast (NE) region has achieved high levels of energy savings; six states in the region (CT, ME, MA, NY, RI, and VT) adopted energy efficiency resource standards that obligate utilities to achieve specified savings goals (Gilleo et al., 2015). Similarly, four NE states have relatively high PV penetration levels that are expected to significantly increase over the next five years (MA, VT, DE, and NH) (GTM and SEIA, 2015). Historic activity levels for EE and PV in the NE are reflected in the assumptions used in the BAU case. All NE states have net-energy metering (NEM) policies in place in addition to various state-level incentives for distributed generation, which are key drivers for distributed PV deployment (NCCETC, 2016).

³ The ACEEE scorecard ranks states by their level of efficiency savings and presence of enabling policies.

⁴ See (Cappers and Goldman, 2009a; Cappers et al., 2009; Cappers et al., 2010; Satchwell et al., 2011; Satchwell et al., 2014).

⁵ We characterize an aggressive scenario resulting in significant sales and peak demand reductions due to installation of efficiency measures and distributed PV systems, but does not represent a “load defection” or “grid defection” scenario. The terms “load defection” and “grid defection” have typically been used to describe the ability for customers to jointly use distributed PV and electric storage systems to self-generate and disconnect entirely from their electric delivery utility (RMI, 2014, 2015). From the utility’s perspective, the implication of “load defection,” “grid defection,” and our aggressive scenario purely on the utility’s loss of future retail sales are somewhat synonymous. However, customers in our aggressive scenario remain connected to the grid because we don’t assume that in the near-term cost-effective, mass-market electric storage systems will be prevalent.

We also consider several ratemaking and regulatory mechanisms which have historically been used to address potential misalignments between utility profit achievement and motivation to pursue customer-funded EE programs (NAPEE, 2007). These mechanisms may also be effective at mitigating similar misalignments with distributed PV. Specifically, in the aggressive EE and PV (AEV) scenario, we model revenue decoupling; rate designs that collect a greater share of non-fuel costs via demand or customer charges; and shareholder incentives. These mechanisms are presently being discussed or have been implemented in several northeast states (IEI, 2014; Center, 2016).

We note several key boundaries of the study scope and method to distinguish it from cost-benefit studies and to ensure that the findings are interpreted and applied appropriately. First, the present study is not a detailed analysis of the value of EE and/or PV. In this study, we utilize the LBNL FINDER model, which is not a utility production cost or planning model.⁶ This financial model contains a relatively high level of detail in its representation of utility ratemaking and revenue collection processes, but less detail in its representation of the physical utility system. As a result, the impacts of EE and/or distributed PV on utility cost-of-service are based on a coarser set of assumptions than what might be possible with utility operations or planning models.⁷

Second, the analysis is focused narrowly on the financial impacts of EE and distributed PV on utility shareholders and ratepayers under existing models of utility regulation in the Northeast. Our analysis does not consider any broader societal benefits of EE and PV (e.g., reduced emissions, economic development, and energy security). Furthermore, by limiting the scope of our analysis to net-metered PV, we do not address potential impacts to utility shareholders or ratepayers that may occur under other compensation schemes (e.g., value-of-solar tariffs, feed-in tariffs).

The report is organized as follows: Section 2 provides an overview of the analytical approach. Section 3 describes the physical, financial, and operating characteristics of the northeast utility. Section 4 presents utility shareholder and customer impacts over time in a future scenario with aggressive efficiency savings goals and higher penetration of distributed PV (i.e., AEV scenario). Section 5 considers the efficacy of ratemaking and regulatory approaches to mitigate negative financial impacts. Section 6 analyzes participating and non-participating customer bills and section 7 summarizes key finding and identifies and discusses topics for future research.

⁶ See Section 2.1 for a description of the FINDER Model.

⁷ Satchwell et al. (2014) included numerous sensitivity analyses to examine how the financial impacts of PV would vary with alternate assumptions related to avoided costs.

2 Overview of Financial Model and Analytical Approach

For the present analysis, we used a *pro forma* financial model - the FINancial impacts of Distributed Energy Resources (FINDER) model - that calculates annual utility costs and revenues based on specified assumptions about the utility's physical, financial, operating, and regulatory characteristics (see Figure 1). The model was adapted from a tool initially constructed to support the National Action Plan on Energy Efficiency (NAPEE) and intended to analyze the financial impacts of EE programs on utility shareholders and ratepayers under alternative utility business models (NAPEE, 2007). LBNL has previously applied the model to evaluate the incremental impact of aggressive EE programs on utilities in the U.S. (Cappers and Goldman, 2009b; Cappers et al., 2009; Cappers et al., 2010; Satchwell et al., 2011) as well as the incremental impact of increasing distributed PV penetration on utilities in the northeastern and southwestern regions of the U.S. (Satchwell et al., 2014). Applications of the LBNL model and analysis of model outputs have been used as part of technical assistance to several state public utility commissions (PUCs) (e.g., Arizona, Nevada, Massachusetts, and Kansas). The FINDER model has also been used to support the State and Local Energy Efficiency Action Network (SEE Action) in regional workshops and training for state regulators and energy offices in the Midwest and Southeast. Through these various applications, the overall structure of the model has been reviewed and vetted by regulators, utility staff, stakeholders (e.g., consumer advocates), EE program administrators and PV installers. Most recently, the FINDER model was ported over to a more dynamic platform (Analytica) and expanded to include a more robust characterization of different rate classes within a utility service territory with increased disaggregation of customer usage patterns over time (i.e., 8760 load profiles).

2.1 FINDER model overview

The FINDER model quantifies the utility's annual costs and revenues over a 20-year analysis period in this study. Importantly, the model performs all cost calculations at the total utility level but has the ability to allocate those costs to different rate classes in order to assess differential revenue impacts. Key outputs include achieved return on equity (ROE) and earnings, average retail rates and customer bills, which can be used by utilities, policymakers, customer groups, and other stakeholders when assessing the impacts and implications of policy proposals and decisions.

Utility costs are based on model inputs that characterize current and projected utility costs over the analysis period. The model represents major cost categories of the utility's physical, financial, and operating environment, including fuel and purchased power, operations and maintenance, and capital investments in generation and non-generation assets (i.e., transmission and distribution investments). Some costs are projected using stipulated first year values and compound annual growth rates (CAGRs); other costs are based on schedules of specific investments (e.g., generation expansion plans). The model calculates the utility's ratebase over the analysis period, accounting for increases due to additional capital investments as well as decreases due to depreciation of existing assets. The model also estimates interest payments for debt and returns for equity

shareholders based on an authorized amount used to finance capital investments and includes taxes on earnings.

The utility's collected revenues are based on retail rates that are set in periodic general rate cases (GRCs) throughout the analysis period (see Figure 1). By default, the model assumes that a GRC occurs at some specified frequency (e.g., every three years); the model also allows the utility to file a GRC that may be triggered by a significant capital investment (e.g. new power plant, proposal to install advanced metering infrastructure).

GRCs are used to establish new rates for customers based on the revenue requirement set in a test year including an authorized ROE for capital investments, the test year billing determinants (i.e., retail sales, peak demand, and number of customers), and assumptions about how the test year revenue requirement is allocated to customer classes and among the billing determinants. The model allows for different types of test years (i.e., historical, current, and future test years).⁸ The particular rate design of the utility consists of a combination of a volumetric energy charge (\$/kWh), volumetric demand charge (\$/kW), and fixed customer charge (\$/customer) for a particular customer class. Model inputs specify the relative share of different types of utility costs that are to be collected from each of these three rate components.

The rates established in a GRC are then applied to the actual billing determinants in future years to calculate utility collected revenue in those years. The model accounts for a period of regulatory lag whereby rates that are established in a GRC do not go into effect until some specified number of years after the GRC. In between general rate cases, certain costs are passed directly to customers through rate-riders (e.g., fuel-adjustment clause or FAC). The model derives an average all-in retail rate metric which reflects the average revenue collected per unit of sales at the utility or customer-class level and accounts for periodic setting of new rates, rate-riders, and delays in implementing new rates.

The financial performance of the utility is measured by the achieved after-tax earnings and achieved after-tax ROE.⁹ We calculated the prototypical utilities' achieved after-tax ROE in each year as the current year's earnings divided by current year's outstanding equity (i.e., the equity portion of the ratebase).¹⁰ Achieved after-tax ROE may, and often does, differ from the utility's authorized ROE. The authorized ROE is typically established by regulators during a regulatory

⁸ Many states allow the utility to file an adjustment to its historical test-year costs during a GRC (i.e., pro-forma adjustment period) to update and correct them to better reflect expectations about normal cost levels. However, our model uses unadjusted historic test year values for ratemaking purposes.

⁹ Achieved ROE is considered to be a measure of how well a company is performing for its shareholders. Achieved ROE is dependent on several factors including the ratio of debt to equity which may artificially inflate a company's achieved ROE if the company is making investments mostly with debt. Achieved ROE is also a useful metric when comparing companies within an industry because the metric is normalized by outstanding shareholder equity.

¹⁰ The model does not take into account changes in financing costs that may result from under- or over-recovery of costs, which may impact ROE.

proceeding and is used in a GRC to determine the amount of return that a utility may receive on its capital investments. Actual utility revenues and costs may – and nearly always do – differ from those in the test year, leading to achieved earnings, and hence *achieved* ROE, that deviates from the authorized level.¹¹ In general, achieved ROE will be less than authorized ROE if, between rate cases, utility costs grow faster than revenues. Conversely, achieved ROE will generally be greater than authorized ROE if utility costs grow slower than revenues between rate cases.

FINDER calculates the prototypical utilities' achieved after-tax earnings as collected revenues minus costs in each year. Achieved after-tax earnings can be different than the utility's authorized earnings, because the *achieved* earnings are based on actual profitability in a given year and the *authorized* earnings are set in the GRC revenue requirement, based on the authorized ROE.¹²

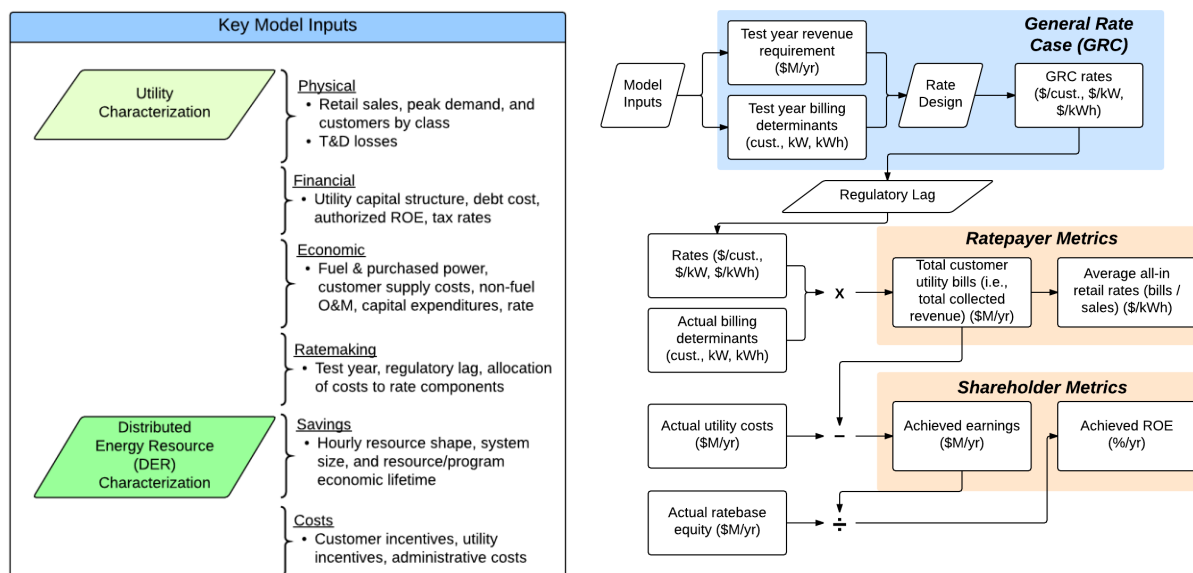


Figure 1. Simplified representation of the FINDER model: Key inputs and stakeholder metrics

Alternative regulatory mechanisms and rate designs can also be implemented in FINDER: decoupling mechanisms (i.e., sales based or revenue-per-customer), lost revenue adjustment mechanisms, and shareholder incentive mechanisms. Alternative rate designs (e.g., high fixed customer charge) are represented by changing the way utility revenues are collected among different billing determinants.

¹¹ In a GRC, utility rates are set such that the test-year revenue requirement produces earnings that are sufficient to reach the authorized after-tax ROE based on the test year costs and billing determinants.

¹² Technically, earnings are not explicitly authorized by state regulators in a GRC. They authorize a ROE, which when applied to the undepreciated portion of a utility's share of equity financed ratebase produces a level of earnings. For our purposes in this report we refer to that as *authorized earnings*.

2.2 Analytical approach

We estimate the financial impacts of a combined portfolio of aggressive EE savings target and PV penetration levels measured as the change from the northeast (NE) utility's costs and revenues under a business-as-usual (BAU) scenario compared to an "aggressive EE and PV" (AEV) scenario (see sections 3 and 4, respectively). The financial impacts, therefore, represent the impacts of the aggressive EE and PV savings achieved in the AEV scenario which are additional to the EE and PV savings assumed in the BAU scenario. If we were to compare the utility's costs and revenues in the AEV scenario to a case with no EE and PV savings, the financial impacts on shareholders and ratepayers would be much larger.

We also analyze several ratemaking and regulatory approaches for mitigating the potential negative financial impacts on utility shareholders that were only applied in the AEV scenario (see sections 5 and 6).

Finally, we report the combined portfolio impacts over a 20-year analysis period (2017-2036) using a 7% discount rate for utility shareholder metrics and a 6% discount rate for ratepayer metrics.¹³

2.3 Analyzing the effects of EE and PV on utility costs and revenues

The FINDER model derives the impacts of distributed energy resources (DER) through several key static and dynamic interrelationships. DERs impact utility billing determinants; specifically retail sales and peak demand, which has an effect on utility costs and subsequently retail rates. DERs reduce volumetric sales based on a direct relationship between the assumed annual DER penetration, expressed as a percent (%) of annual sales on a customer-class basis, and the utility's class-level sales. Reductions in the utility's peak demand are derived through dynamic relationships of several variables that take into account the specific timing of each DER relative to the utility's hourly load and takes into account potential differences in alignment between when the DER causes reductions in the utility's load (either through the customer's PV output or energy savings from installed efficiency measures) and the utility system annual peak demand.

The timing of DER savings and the utility annual peak demand is a key driver in the analysis of the joint impact of EE and PV on utility costs, retail rates and collected revenues. EE and PV reduce volumetric sales and customer peak demand. However, there are important differences in the timing of energy and demand reductions from EE and PV. EE programs tend to produce energy and demand reductions over many hours when affected end-uses are operating while PV reduces energy and demand only in hours when the PV systems operate (i.e., during the daylight hours). The timing of energy and demand savings from EE and PV is important to take into account as they

¹³ Discount rates selected for utility shareholder metrics represent the approximate weighted average cost of capital (WACC) for a regulated electric while a slightly lower discount rate was selected for average all-in retail rates intended to represent a lower opportunity cost for ratepayers.

relate to customer class and utility monthly and annual peak demands, which drive projections of future costs, retail rates, and revenues collected on a volumetric basis through energy and demand charges.

We note two particular feedback effects that the FINDER model does not account for in the present study and that would have potential implications for our results. First, we do not represent the feedback effects between retail rate impacts and EE and PV adoption rates. An increase in retail rates will improve the economics of EE and PV investment to customers (i.e., lower payback time for installed EE measures or PV system) which, all else being equal, would be expected to drive greater EE and PV adoption and thus lead to increased reductions in the utility's future load. Second, we do not represent the feedback effects of changes in retail rate designs on customer load shapes that would also result in greater or lesser EE and PV adoption, all else being equal. Instead, we construct an annual EE and PV penetration forecast that is adhered to regardless of these or other exogenous factors.

3 Prototypical Northeast Utility Characterization

In this section, we describe the key assumptions used to model the northeast (NE) utility in the BAU case and present 10-year projections of the utility’s costs (i.e., revenue requirement), average retail rates, collected revenues, shareholder earnings, and ROE without PV. The prototypical NE utility is intended to generally represent a distribution utility in the northeast with operating, financial, and regulatory characteristics that are regionally representative (see Table 1). Historically, many Northeast states have set and achieved relatively aggressive energy savings goals while customer-sited PV deployment rates are increasing in a number of these states.

Table 1. Characterization of a prototypical NE utility: Key Inputs and values

Key Input	Value
Asset Ownership	Distribution-only
2017 Retail Sales Level / CAGR	20,816 GWh / -0.2%
2017 Peak Demand Level / CAGR	4,205 MW / 1.0%
2017 Retail Customer Count / CAGR	1,341,516 / 1.0%
Purchased Power and Customer Supply Costs CAGR	3.3%
Non-fuel Operations & Maintenance Costs CAGR	1.8%
2017 Ratebase (net accumulated depreciation)	\$2.8B
2017 All-in Retail Rate Level	13.4 ¢/kWh
Frequency of General Rate Case Filings	Every 3 years
Regulatory Lag ¹⁴	1 year
Test Year	Historic
Authorized ROE	10.0%
Debt and Equity Share	48%:52%
Weighted Average Cost-of-Capital	7.87%

The NE utility is a “wires-only” utility in a restructured northeastern state that owns and operates the distribution network, but does not own transmission or generation assets. The utility serves as the default supplier of generation service for customers within its distribution service territory and all energy and generation capacity required to serve those customers is procured through market purchases.¹⁵

We developed a 20-year cost and load forecast for the prototypical NE utility by starting with the 2015 general rate case filing of National Grid in Massachusetts (MA) (“Mass Electric”) (Utilities, 2014). The general rate case filing included a cost-of-service study that provided reasonable starting year cost levels, starting year class-level retail sales, peak demand, and customer counts, and class-level cost allocations and rate designs. Growth in retail sales and peak demand are based

¹⁴ Regulatory lag is the period of time between the filing of a GRC and when new rates take effect.

¹⁵ We do not uniquely model the supply costs of customers that contract with competitive retail energy suppliers. Because publicly available information on the supply costs in retail competitive markets is not available, we assume that those commodity costs would be comparable to those incurred by customers taking default service from the NE utility.

on MA statewide average annual growth rates in the 2015 ISO New England (ISO-NE)'s Forecast Report of Capacity, Energy, Loads, and Transmission (England, 2015). We also relied on the 2015 Synapse Avoided Energy Supply Costs in New England (AESC) report for current and future projections of energy and capacity costs (Hornby et al., 2013). Data from Mass Electric were used to seed many of the elements of our initial utility characterization. However, we relied heavily on broader regional source material to inform how those elements should be altered to better reflect the general northeast operating and financial conditions for electric utilities. ***The prototypical NE utility used in this analysis is not intended to represent Mass Electric.***

The revenue requirement and customer supply costs of the NE utility total \$2.8B in 2017 and grow 2.7% per year, on average, to \$3.6B in 2026 (see Figure 2).¹⁶

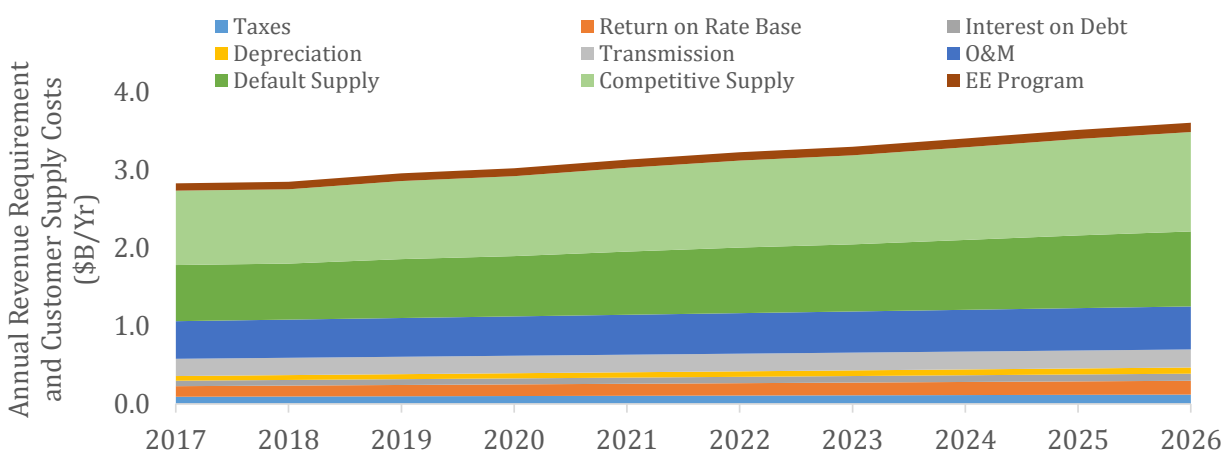


Figure 2. Annual revenue requirement and customer supply costs of prototypical NE utility

The NE utility has retail sales of 20,816 GWh and 4,205 MW of peak demand in 2017. In the BAU, retail sales are projected to decline by -0.2% per year from 2017 to 2026, driven, in part, by existing supporting EE and PV policies that result in modestly increasing EE program participation and penetration of distributed PV systems (see Figure 3). Utility peak demand increases by about 1.0% annually and includes reductions in peak demand from forecasted modest penetrations of EE and PV in the BAU. Importantly, these projected growth rates in retail sales and peak demand are consistent with expected load growth in the northeast United States. For example, the ISO-NE 2015 CELT Report forecasts an annual decline of -0.04% in retail sales and 0.54% per year peak

¹⁶ The revenue requirement used to determine base retail rates in the model does not include the power supply costs associated with competitive suppliers who purchase power for non-default service customers (i.e., competitive supply customers), although those costs are included for reference in Figure 2. Transmission costs are the ISO-NE access charges that are collected from NE utility customers in base retail rates. Transmission costs are referenced as a separate cost in Figure 2 because they are not included in the NE utility's ratebase.

demand growth for the northeast region through 2024, inclusive of the effects of EE and distributed PV.¹⁷

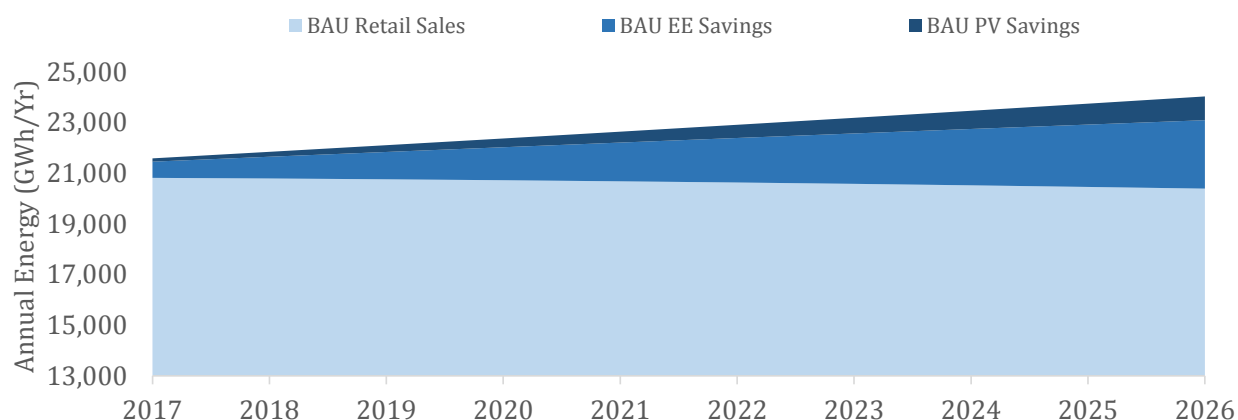


Figure 3. Annual retail sales including contributions of EE and PV savings of prototypical NE utility

Default customer and competitive supply costs (i.e., energy and capacity) account for around 60% of the total costs and grow at 3.3% per year. The NE utility purchases all energy and capacity for default service customers through wholesale market purchases. Annual energy and capacity costs are based on forecasted peak, off-peak, and capacity prices in the AESC report (Hornby et al., 2013).¹⁸ Default customer supply costs are also inclusive of the costs to meet a mandated RPS obligation that starts at 12% of annual retail sales in 2017 and increases by 1% of annual retail sales each year of the analysis period (reaching 21% in 2026).

The NE utility also makes regular distribution system investments to maintain its distribution network and meet modest demand growth. We assume such investments represent 33% of total utility capital expenditures and grow at 1.0% per year through 2018 then increasing to 1.5% per year growth through 2026.¹⁹ Distribution system investments are reflected in the return on rate base, depreciation, taxes, and debt interest cost categories shown in Figure 2.

The NE utility collects these costs through a variety of rates and riders. Supply costs for default service customers are recovered via a fuel adjustment charge (FAC) that directly passes through the costs to customers and collects them annually in the year that they are incurred. “Non-fuel

¹⁷ We did not use the regional ISO-NE load forecasts because it did not match the underlying cost assumptions that are based on a MA utility. ISO-NE 2015 Forecast Report of Capacity, Energy, Loads, and Transmission Regional System Plan is available at: <http://www.iso-ne.com/system-planning/system-plans-studies/celt>

¹⁸ See Appendix B. <http://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england>

¹⁹ The increase in annual cost growth rates of 0.5% in 2019 reflects a higher cost inflation rate in the long-term. Our distribution system investment costs do not assume large, lumpy distribution system investments, like advanced metering infrastructure.

costs” (i.e., all costs except purchased power and customer supply costs) are recovered via base utility retail rates set at the time of a GRC and take effect one year after the general rate case. We assume a rate design for the prototypical NE utility based on Mass Electric’s 2015 rate case filing for the three major customer classes. Table 2 shows the percentage of non-fuel revenues collected via an energy, demand²⁰, and customer charge for the residential, commercial and industrial (C&I), and street lighting classes.

Table 2. Customer class rate designs for a prototypical NE utility: Share of non-fuel revenue collected via energy, demand and customer charges

Residential Class			Commercial & Industrial Class			Street Lighting Class		
Energy	Demand	Customer	Energy	Demand	Customer	Energy	Demand	Customer
82%	0%	18%	42%	47%	11%	7%	0%	93%

Figure 4 shows the annual amounts of non-fuel collected revenues compared to annual non-fuel costs. Non-fuel costs are higher in all years than non-fuel collected revenues due to several factors. First, non-fuel revenues are based on the amount of each rate component (e.g., ¢/kWh) and the billing determinant (e.g., retail kWh sales). Thus, growth in non-fuel revenues is based on growth in billing determinants between rate cases. Energy, demand, and customers grow at a lower rate than the projected growth in non-fuel costs (1.8% per year). Second, the test year and regulatory lag assumptions result in a multi-year period between when costs are incurred and when they are reflected in new retail rates. The implication of regulatory lag results in the “see-saw” effect in Figure 4, in which non-fuel revenues noticeably increase in the year after new rates are implemented. As a general matter, this potential under-collection of non-fuel costs is an issue for most regulated utilities and often occurs even in the absence of aggressive EE programs and distributed PV penetration.²¹

²⁰ FINDER employs a non-coincident monthly peak demand charge.

²¹ Under traditional cost-of-service regulation, reliance on historic test years provides utilities with an economic incentive to reduce non-fuel costs between rate cases.

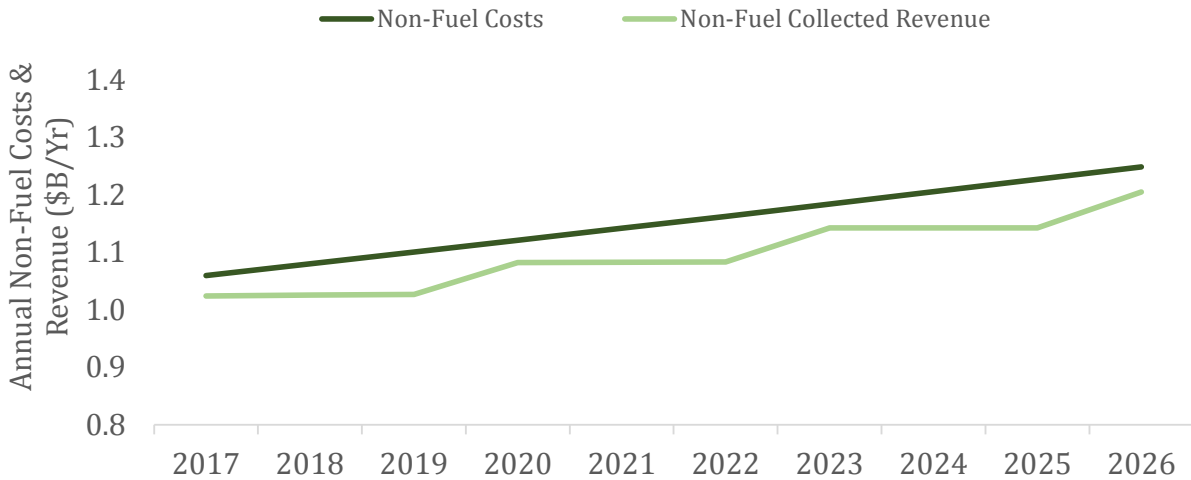


Figure 4. Annual non-fuel costs and collected revenue for a prototypical NE utility

The NE utility’s achieved after-tax ROE and achieved after-tax earnings are lower than authorized levels over the entire analysis period (see right axis of Figure 5). Specifically, the utility achieves an average after-tax ROE of 7.8% from 2017 to 2026 compared to its authorized ROE of 10.0%. Total achieved after-tax earnings, on a PV basis discounted at 7%, are \$843M over the 2017 to 2026 period and achieved earnings are less than authorized earnings. The under-earning is due to the underlying difference between the growth rates of non-fuel costs and non-fuel revenues discussed earlier, which is consistent with prior studies (e.g., Satchwell et al., 2014) and industry reports (e.g., EEI 2013).

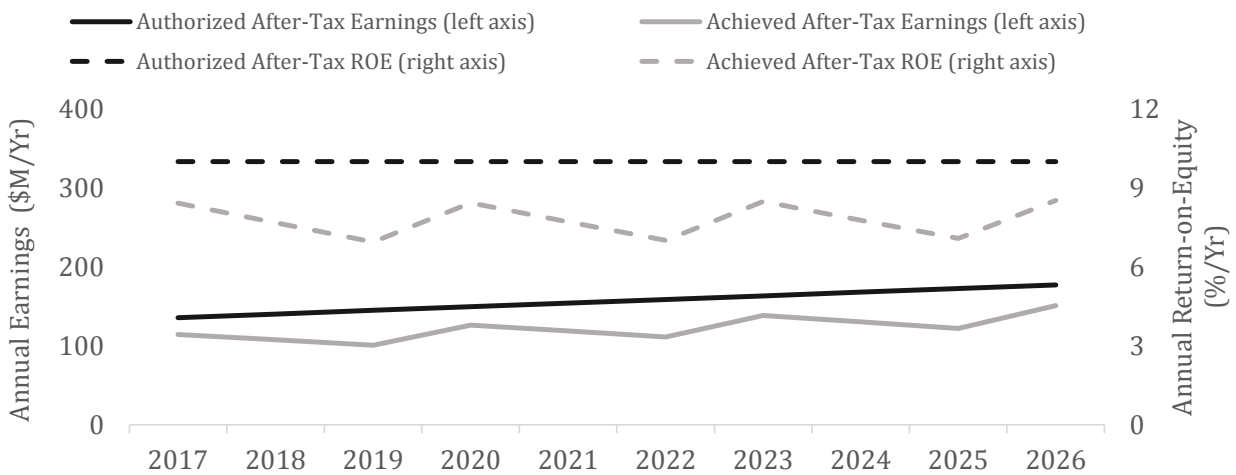


Figure 5. Authorized and achieved earnings and ROE for a prototypical NE utility

4 Financial Impacts of a Combined Aggressive EE and PV Portfolio on a Prototypical NE Utility

In this section, we describe a future scenario (AEV) in which state regulators have established much more aggressive savings goals for EE programs and the utility predicts that there will also be much higher penetration of distributed PV compared to the BAU case. Energy savings and PV penetration ramp-up over the ten year analysis period (i.e., 2017 to 2026). We report financial impacts on a 20-year present value basis in order to capture “end effects” (i.e., the impacts of EE and PV measures installed during 2017-2026 continue well into the years afterwards).

4.1 Aggressive EE portfolio assumptions

We assume that 100% of the EE measures are derived from ratepayer funded programs administered by the utility, which is the dominant model in the Northeast.²² These EE programs are an input assumption in the FINDER Model and characterized by customer-class portfolio annual savings, costs, measure lifetime, and hourly shape.

Table 3. Energy efficiency savings target for a prototypical NE utility in aggressive EE/PV scenario (first year share of total utility annual retail sales without EE and PV)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2.00%	2.25%	2.50%	2.60%	2.70%	2.80%	2.90%	3.00%	3.10%	3.10%

Table 3 shows the annual savings target starting at 2.0% percent of total utility annual retail sales in 2017, ramping up to 3.1% in 2025. These targets are reported as percent of total retail sales, not incremental to any EE or PV savings in the BAU scenario. Currently, six NE states (CT, ME, MA, NY, RI, and VT) have an energy efficiency resource standard (EERS) mandating a specific percentage of energy savings from EE programs. The EERS targets for 2015 range from 0.8% in NY to 2.6% in MA. The NE utility savings goal of 2.0% in 2017 is essentially double the level of existing EE program savings assumed in the BAU scenario. The 2025 savings goals represent an extrapolation of MA savings goals, which are the most aggressive in the region. The aggressive EE portfolio savings targets are meant to be representative of an aggressive EE scenario for utilities in the entire NE region.

The remaining EE portfolio input assumptions are specific to savings and costs at the program- and portfolio-level. Our starting place for the residential and C&I portfolio measure lifetimes and costs is LBNL’s Cost of Saved Energy database (Billingsley et al., 2014; Hoffman et al., 2015). We specifically used 2013 MA statewide average residential and C&I portfolio program administrator costs (i.e., sum of administrative and measure incentive costs) and portfolio average measure

²² There are a few notable exceptions. For example, the state of Vermont has a third-party program administrator – Efficiency Vermont. In New York, both NYSERDA and utilities administer efficiency programs

lifetimes. We then compared the MA statewide values to program administrator costs of other utility administrators in the northeast and made adjustments to align the starting year costs with the regionally representative starting year savings level (i.e., 2.0% total retail sales).

We assume a 2017 program administrator cost of \$43.50/lifetime-MWh for the residential portfolio and \$21.30/lifetime-MWh for the C&I portfolio, which is within the range of program administrator costs for states in the NE region with aggressive EE savings goals (see Table 4). We assume these costs escalate at 1.0% per year through 2018 and 1.50% per year through 2026, reflecting short- and long-run cost inflation. We also assume a residential portfolio average measure lifetime of 9.2 years and C&I portfolio average measure lifetime of 15.6 years, based on MA 2013 program measure lifetimes. The assumed costs, measure lifetimes, and savings levels produce a total EE program budget for the utility of \$187M in 2017, which then almost doubles to \$370M in 2026.

Table 4. Program administrator costs for energy efficiency portfolios by NE state and prototypical NE utility in aggressive EE/PV scenario (\$/Lifetime MWh)

Customer Class	NE	MA	ME	RI	VT
Residential	\$43.50	\$74.40	\$31.50	\$57.00	\$32.80
C&I	\$21.30	\$21.30	\$17.70	\$28.00	\$32.60

The FINDER Model also assumes an hourly shape for the EE residential and C&I portfolio that represents the relative share of energy savings in each hour of the year and determines the timing of when EE portfolio savings reduce monthly and annual customer class non-coincident peak demand. MA EE program administrators report ex ante seasonal peak and off-peak savings values. We used a savings-weighted average of the 2014 MA program administrator values and applied them to the respective seasons, peak, and off-peak hours to develop residential and C&I portfolio hourly shapes.

4.2 Aggressive distributed PV market penetration assumptions

Utilities in the northeastern United States are not, at present, directly responsible for the delivery of customer-sited PV. Our analysis is consistent with this experience, where we assume 100% of the customer-sited PV is delivered by third-party (i.e., non-utility) entities. Distributed PV is an input assumption in the FINDER model and is characterized by annual market penetration, system capacity factors, ownership types, hourly shape, and integration costs.

Table 5. Market penetration levels for distributed PV for a prototypical NE utility in aggressive EE/PV scenario (first year share of total utility annual retail sales without EE and PV)

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
0.73%	0.90%	1.01%	1.06%	1.13%	1.19%	1.26%	1.31%	1.38%	1.40%

Table 5 shows our assumed annual PV penetration rates as a percent of total annual retail sales that starts at 0.73% in 2017 and ramps up to 1.40% in 2026.²³ The PV deployment rates are based on forecasted penetration in MA through 2020 (GTM and SEIA, 2015), assuming continuation of existing state and federal enabling policies (e.g., tax credits and NEM compensation). We chose MA state forecasts because it represents the most aggressive current and forecasted PV penetration in the NE region. We extrapolated the state-level 2020 forecasted penetration to 2026 assuming a slight decrease in annual growth, which is meant to represent increased market saturation and tapering tax credits for distributed PV.

Projecting future growth in customer-sited PV is a highly speculative exercise as it is based in part on policy drivers as well as consumer preferences and attitudes. For comparison, GTM and SEIA (2015) forecasted distributed PV penetration at 2.9% of U.S. retail electric sales by 2020, with a handful of states (e.g., CA, HI, AZ) accounting for the majority of the growth in PV penetration levels.

Finally, we note that PV penetration is driven, in large part, by the economics of ownership. Any increase or decrease in utility rates and/or change to NEM compensation may affect the value of such investments resulting in a lower or higher growth in distributed PV, all else being equal. We do not model this feedback-loop and instead take PV penetration rates as an input assumption. We discuss the financial impacts on the utility of directional changes in PV penetration levels in qualitative terms (e.g., adverse financial impacts on utility shareholder increase as PV penetration levels increase, all else being equal).

To determine the total capacity of installed PV and number of systems installed to meet annual PV penetration rates, we assume a 14.8% and 12.9% capacity factor for residential and C&I systems, respectively. The distributed PV capacity factors come from NREL's System Adviser Model and are specific to MA.²⁴

We also assume that the utility incurs an additional cost to integrate distributed PV resources production (e.g., procuring additional and more flexible energy and capacity resources). We assume a \$3/MWh integration cost based on an average value at 2-3% penetration (Luckow et al., 2015). We assume an hourly shape for the PV to determine the timing of PV impacts on hourly sales using NREL's PV Watts to derive an hourly shape using MA weather and default PV system characteristics (e.g., 20-degree tilt).²⁵

²³ These PV market penetration rates are reported as a % of retail sales without any incremental EE or PV savings in the BAU scenario.

²⁴ <https://sam.nrel.gov/>

²⁵ <http://pvwatts.nrel.gov/>

4.3 Impacts on retail sales and peak demand

The aggressive EE and PV portfolios produce significant declines in the NE utility’s retail sales and peak demand. Retail sales decline by 3.7% per year and peak demand declines by 0.1% per year during the ten year period (i.e., 2017-2026) as EE savings and PV installations ramp-up (see Figure 6). Because the EE savings targets and PV penetration levels are specified in terms of a percent reduction of retail sales, they each reduce NE utility sales on a one-for-one basis. As shown in Figure 6, the relative contribution of the EE portfolio to reducing utility loads is larger than the PV portfolio because of our forecast of greater EE savings than PV market penetration. Note that the EE and PV savings depicted in Figure 6 are incremental to the BAU portfolio savings from EE and PV.

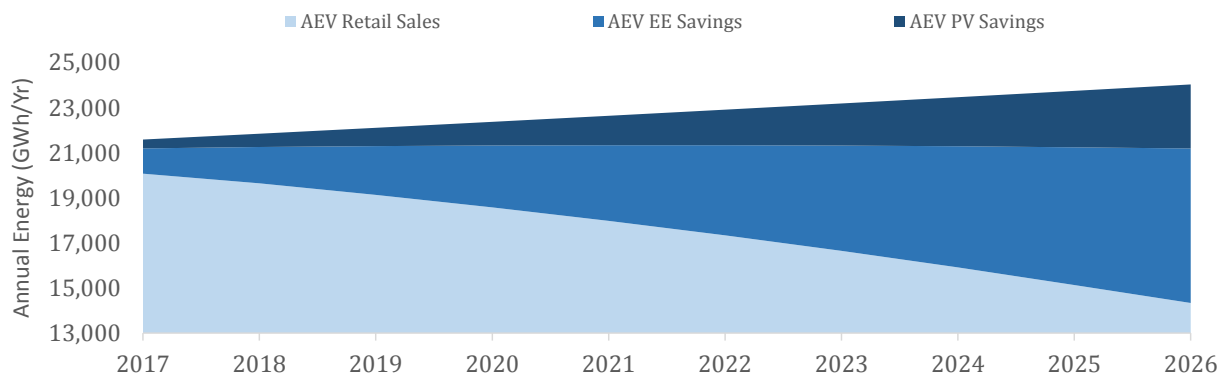


Figure 6. Forecasted retail sales and EE and PV savings for a prototypical NE utility in the aggressive EE/PV scenario

The impacts of EE and PV on peak demand depend on the timing and coincidence of the EE and PV portfolios relative to the utility’s annual peak demand. Figure 7 shows the forecasted annual peak demand for a NE utility from 2017 to 2026 and the coincident peak demand savings attributable to the aggressive EE and PV portfolios. The prototypical NE utility used in this analysis has a system peak that occurs in the summer months (i.e., June, July, and August) generally between 4 and 6pm *prior to the addition of EE and PV savings*. Energy efficiency programs typically reduce energy in more hours than PV programs because EE programs target end uses with more hours of operation while PV programs are limited to hours with sunlight. The coincident peak demand impact of distributed PV is quite modest compared to EE resources – a 36 MW reduction for PV compared to a more than 700 MW reduction for EE in 2026. Because the timing of maximum EE savings and maximum PV output does not coincide perfectly with the utility’s annual peak demand, EE and distributed PV resources reduce utility coincident peak demand on a less than one-for-one basis.²⁶

²⁶ In fact, the timing of the utility system peak changes as the analysis period progresses due to the effects of increased penetration of EE and PV. This is why the size of the EE and PV coincident peak demand impacts in Figure 7 is reduced between 2018 and 2019, just as incremental EE and PV energy savings are ramping up.

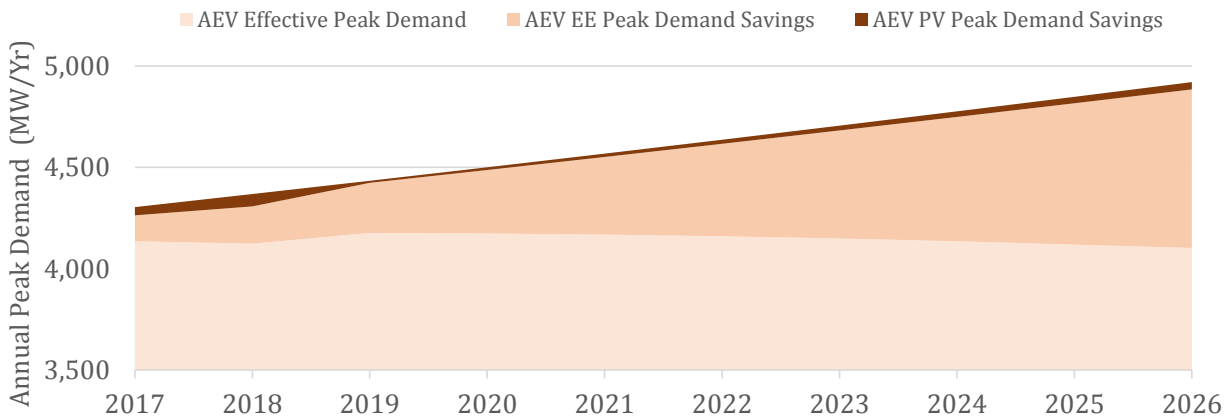


Figure 7. Forecasted annual peak demand and EE and PV savings for a prototypical NE utility in the aggressive EE/PV scenario

4.4 Impacts on utility costs

The FINDER Model calculates changes in the utility revenue requirement under the aggressive EE and PV scenario, including accounting for changes in retail sales and peak demand. In the aggressive EE/PV scenario, the NE utility is able to reduce its purchased power costs for energy and capacity. For RPS compliance, the NE utility purchases fewer renewable energy credits to meet the RPS with EE and PV compared to the BAU scenario based on reduced retail sales. More aggressive deployment of EE and PV also reduces purchased power costs at the bulk power system level. Since EE and distributed PV are located at the customer premises, reductions in sales and peak demand at the bulk power system level are greater than at the customer level due to transmission and distribution (T&D) network losses. For the NE utility, we assume average losses of 4%.

The NE utility owns and operates distribution facilities, and makes investments in its distribution system to meet increasing energy, demand, and customer growth (i.e., “growth-related CapEx”) or to replace aging infrastructure (i.e., “non-growth-related CapEx”). We assume that the NE utility will continue to make non-growth-related CapEx investments regardless of the level of energy, demand, and customer growth (e.g., replace broken or poorly operating infrastructure) as it must maintain a minimum level of distribution service and reliability. However, we assume a portion (33%) of investments are growth-related CapEx and the addition of EE and PV reduces this growth-related CapEx proportional to reductions in annual peak demand, leading to corresponding reductions in returns on ratebase, depreciation expenses, interest, and taxes.

Given the modeled relationships described above, the NE utility’s costs are reduced by 3% (\$1.1B on a 20-year present-value basis at 7% discount rate) in the aggressive EE/PV scenario, with

further details on the underlying source of cost reductions listed in Table 6. Virtually all of the cost reductions (99%) are attributable to reduced costs of purchased power. The relatively small decrease in non-fuel costs compared to reductions in purchased power costs (i.e., “fuel”) have important implications for the financial impacts on utility shareholders and ratepayers.²⁷

Table 6. Sources of reduced utility costs in the aggressive (AEV) scenario as modeled in FINDER

Cost Category	Impact
Purchased Power	Reduced energy and capacity market purchases
	Reduced transmission access charges
	Reduced RPS procurement costs
	Reduced losses
O&M	None
Depreciation	Reduced distribution system CapEx
Interest on Debt	Reduced distribution system CapEx
Return on Ratebase	Reduced distribution system CapEx
Taxes	Reduced distribution system CapEx
	Reduced collected revenue
	Reduced achieved earnings

We note two important likely impacts of the aggressive EE and PV scenario on utility costs that we do not represent within this study. First, retail sales and peak demand reductions may put downward pressure on competitive energy and capacity costs (i.e., “demand reduction induced price effects” or DRIPE), which would result in lower total purchased power costs. Hornby et al. (2015) forecasted DRIPE for the northeast region’s energy and capacity costs and showed a small reduction in energy prices in only the first four years of its forecast (i.e., 2015 to 2018). Furthermore, no reduction in capacity costs was found because ISO-NE is forecasted to be in an excess capacity situation for the foreseeable future. These findings are similar to other studies of the impacts of distributed generation on wholesale energy and capacity prices in the NE region (Berkman et al., 2014). However, all of these analyses have focused on penetration levels of EE and PV well below those that are modeled in the AEV scenario. To apply DRIPE in our analysis would either require applying the same very small impact found by previous research studies or attempting to extrapolate the results to higher penetration levels well outside the range and time frame used in those original analyses. Given the uncertainty of the precision associated with an application of these different approaches, we chose not to apply DRIPE at all. The implication is that our reported impacts on energy and capacity costs are likely a lower bound estimate under such high penetration of EE and PV systems.

Second, distributed PV may require additional investments in a utility’s T&D system because of its location close to customer loads and the new potential for two-way power flows for which

²⁷ If we assumed that a higher portion of CapEx costs were growth-related (i.e., higher than 33%), we would expect greater cost reductions in the AEV scenario and a somewhat higher proportion of non-fuel cost reductions relative to purchased power cost reductions, all else being equal.

distribution systems were designed to accommodate. Various T&D planning studies are beginning to address this issue. Although they apply a range of approaches to perform such analyses, all come to the same conclusion; results are primarily driven by the detailed conditions of particular distribution feeders (Mills et al., 2016). Furthermore, it is unclear if the investment in EE by a customer on the same distribution feeder with a PV system or even by one without a PV system will have an exacerbating or mitigating effect on the need for additional T&D investment. Given the limits of the existing literature in terms of the uncertainty in the direction and magnitude of impacts coupled with the absence a detailed distribution-system planning study for our NE utility at the modeled EE and PV penetration levels, we do not model any additional T&D investments to accommodate PV. We also do not attempt to predict the implications of this decision on our results.

4.5 Impacts on collected revenues

The NE utility collects revenues from customers based on billing determinants (i.e., sales, demand, and customer count) and the rates for each billing determinant (i.e., \$/kWh, \$/kW, and \$/customer). The impacts of EE and distributed PV on total utility collected revenues are thus a function of changes in billing determinants and changes in the rates for each billing determinant caused by EE and PV. The change in billing determinants is simply the reduction in retail sales and peak demand while the change in rates reflects the net effect of EE and PV on test-year costs (i.e., revenue requirements) and billing determinants used within each general rate case (GRC).

Savings from EE and distributed PV reduces “fuel” and “non-fuel” revenues and are important to distinguish in understanding the impacts to utility shareholders and ratepayers. Because purchased power and supply costs (i.e., “fuel” costs) are a direct pass-through to customers via a fuel adjustment clause (FAC) mechanism, there is a one-for-one and contemporaneous reduction in fuel costs and fuel revenues. As such, the NE utility perfectly collects fuel-related revenues from customers to match fuel costs; any downward change in fuel costs from EE and distributed PV leads to lower fuel-related revenues collected from customers.

However, non-fuel costs and non-fuel revenues are not perfectly matched due to the differences between cost structure and retail rate design (i.e., many fixed costs are allocated to volumetric energy and demand rates) and the GRC process (i.e., new rates that are set in a GRC take effect with a lag). It is the change in non-fuel collected revenues relative to the change in non-fuel costs from EE and PV that ultimately translate to adverse impacts on utility shareholder ROE and earnings.

To illustrate, Figure 8 compares the non-fuel revenues of the NE utility under the aggressive EE and PV scenario to the corresponding reductions in non-fuel costs (i.e., revenue requirement). Throughout the analysis period, the utility’s non-fuel revenue requirement consistently exceeds collected non-fuel revenues by \$60-212 million annually. This occurs, in part, because of the greater assumed growth rate in non-fuel costs for the NE utility than billing determinants and the result that distribution system costs are not greatly reduced via the EE and PV savings.

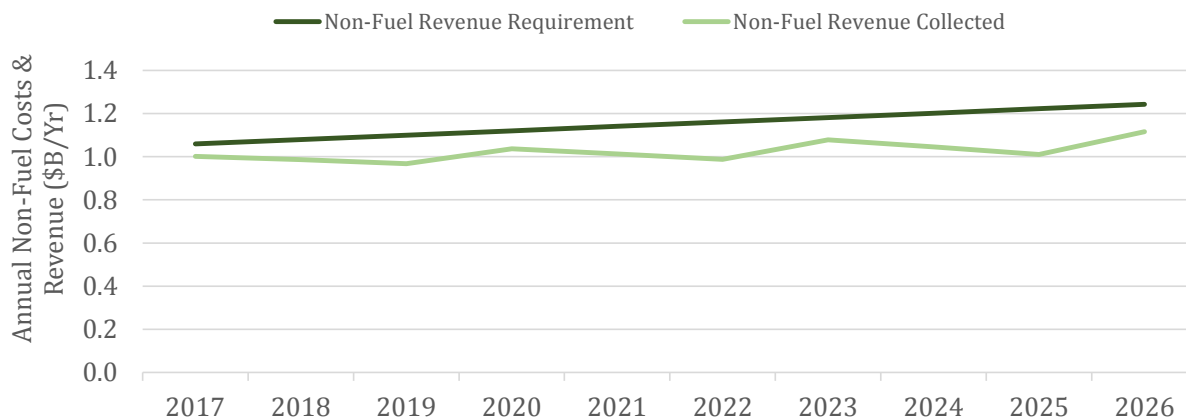


Figure 8. Reduction in prototypical NE utility non-fuel revenue requirement and collected revenues in the aggressive EE/PV scenario

4.6 Impacts on ROE and earnings

EE and distributed PV may reduce shareholder earnings through two separate means. First, if aggressive deployment of EE and PV reduces utility revenues more than utility costs, then net revenues or earnings are likewise reduced (i.e., the “revenue erosion effect”). Second and separately, EE and PV savings may also diminish future earnings opportunities by reducing or deferring capital investments that would otherwise contribute to the utility’s ratebase (i.e., the “lost earnings opportunity effect”).²⁸ Potential mechanisms exist for mitigating earnings erosion and/or providing the utility with additional earnings opportunities (see section 5).

Figure 9 shows the earnings impacts for the NE utility over 20-years on a present-value basis. The after-tax earnings achieved by the NE utility are \$364M (24%) lower in the aggressive EE/PV scenario compared to the BAU scenario.²⁹

²⁸ An increase in earnings is valuable to shareholders only if the return on future investments is greater than the cost of equity (Koller et al., 2015), which presently would be the case for most utilities. The prototypical NE utility in our analysis, however, may present a case in which the ROE of future investments may not cover the cost of equity, in which case the deferral of future capital investments would benefit shareholders. See (Kihm, 2009) for a discussion of the motivations for a utility to invest in capital in a future with increased EE when returns on future investments are greater or less than the cost of equity.

²⁹ EE and PV savings ramp-up over ten years (i.e., 2017 to 2026) but we report earnings impacts over 20-years (i.e., 2017 to 2036) to capture the full value of capital investment deferrals that continue beyond the initial 10-year period when EE measures and customer-sited PV are installed. These “end-effects” are limited to deferred distribution system investments for the NE utility, given that the utility does not own generation.

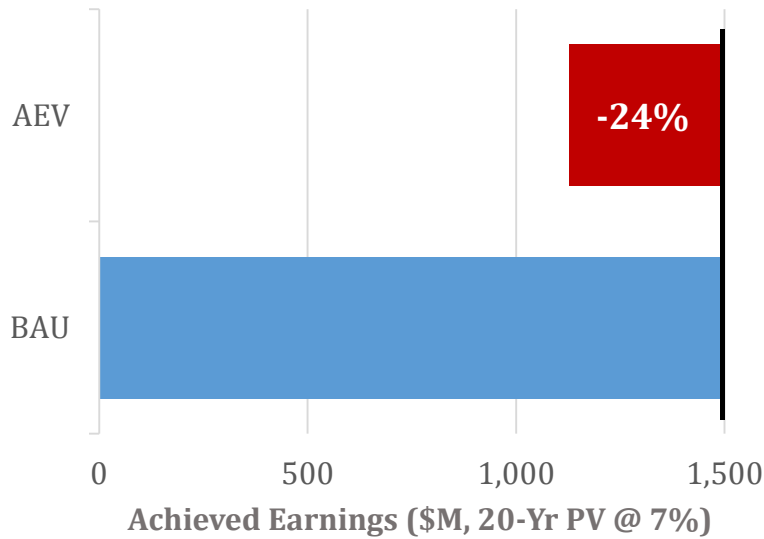


Figure 9. Impacts of aggressive EE/PV scenario on achieved earnings of the prototypical NE utility

It is important to recall that the NE utility achieved ROE is below its authorized ROE in the BAU scenario: average achieved ROE of 8.2% over 20 years compared to an authorized ROE of 10% (see section 3).³⁰ The addition of aggressive EE program savings and increased customer-sited PV penetration exacerbates those underlying conditions, leading to further erosion of ROE.

The NE utility’s average achieved ROE is 200 basis points lower (or average achieved ROE of 6.2%) in the AEV scenario compared to the BAU scenario over 20 years (see Figure 10). In relative terms, this represents a 24% reduction in average utility shareholder returns over the 20 years.

³⁰ This occurs primarily because the utility’s projected costs are growing faster than their revenues due to existing regulatory practices (e.g., use of historic test years, one-year lag in approving new rates filed as part of a GRC)

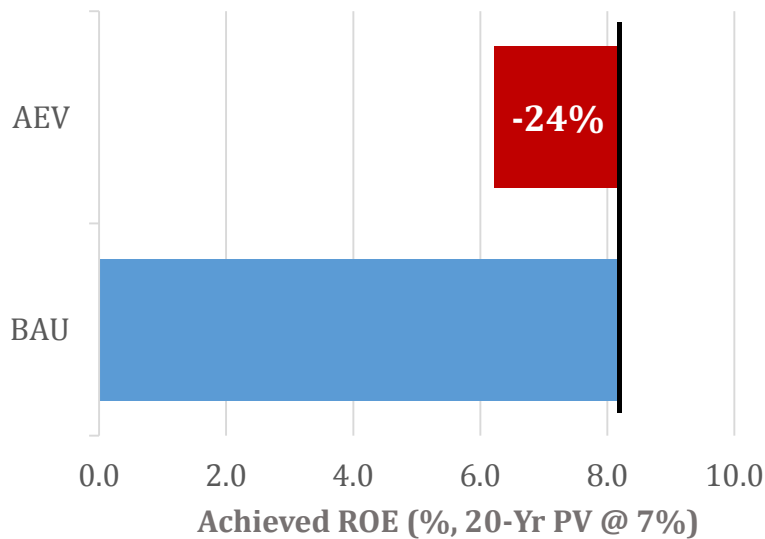


Figure 10. Impacts of the aggressive EE/PV scenario on the prototypical NE utility’s achieved average ROE

4.7 Average retail rate impacts

Within the timeframe of our analysis, EE program savings and customer-sited PV impacts both affect average, all-in rates of retail customers in two, inter-related ways. First, they affect the retail rates set within each GRC through the net result of reductions in the test-year utility costs and billing determinants used to establish rates. EE program savings and customer-sited PV generally tend to reduce utility costs by less than revenues collected from reduced utility sales. As a result, average retail rates established through each GRC increase with the addition of EE and PV. Second, EE program savings and customer-sited PV impacts both affect average all-in retail rates in the years between GRCs, though this effect is simply a mathematical artifact. Average all-in rates are, by definition, equal to total collected revenues divided by total retail sales in any given year. Retail sales (the denominator) are reduced due to the incremental increased annual investment in EE and PV on the system. Because of these lower volumetric energy billing determinants, the revenues collected on an annual basis will also be reduced. However, the reductions in revenues are necessarily smaller than the reductions in retail sales, given that some portion of revenues are derived from fixed customer charges (which are unaffected by EE and PV) and demand charges (which are only marginally affected by EE and PV).

For the NE utility, the all-in average retail rate in the aggressive EE/PV scenario is 3.5 cents/kWh (22%) higher over 20 years than in the BAU scenario (see Figure 11). All-in average retail rates in the AEV case start at 14 cents/kWh in 2017 and increase by 3% per year, on average, over the 20-year analysis period.³¹ This significant increase in average all-in retail rates is driven by two

³¹ The 3% growth rate is a compound annual growth rate that smooths the significant year-to-year increases in retail rates when new rates take effect. As a point of reference, all-in average retail rates increase by 2% per year in the BAU scenario.

factors: (1) the combined EE and PV portfolio reduces only a small portion of non-fuel costs; and (2) the dramatic decrease in utility retail sales over which the remaining utility costs are spread.

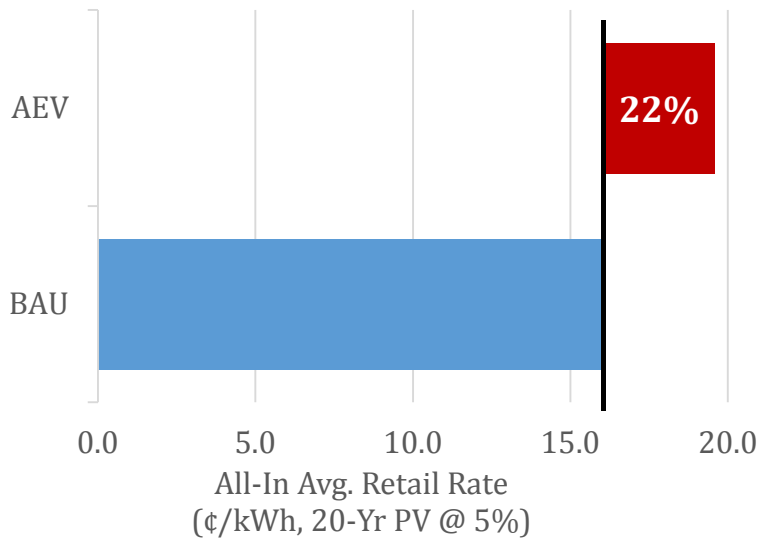


Figure 11. Impact in all-in average retail rates for the prototypical NE utility in the aggressive EE/PV scenario

5 Efficacy of Shareholder Mitigation Approaches

In this section, we examine the effectiveness of several regulatory/ratemaking strategies that are commonly proposed to mitigate the financial impacts on utility shareholders of aggressive pursuit of EE and distributed PV (see Table 7). The regulatory and ratemaking strategies are typically discussed in connection with EE programs but have analogues that might apply to PV. Our quantitative analysis is illustrative and is not intended to be exhaustive of all potential mitigation approaches that could be considered.³² The approaches examined in this study specifically target the adverse impacts on utility shareholders from EE and customer-sited PC, associated with revenue erosion and lost earnings opportunities. It is important to recognize that these mitigation strategies that may benefit utility shareholders may also exacerbate the rate impacts on customers, exemplifying an important tradeoff that can often arise.³³ Importantly, we do not suggest regulators *must* take action to mitigate shareholder impacts. Rather, we illustrate the extent to which common mechanisms may mitigate the shareholder impacts, if such action were deemed appropriate and necessary by the regulator.

We examine each of the mitigation options in Table 7 in isolation considering whether they effectively address adverse impacts on shareholders. Our analysis of mitigation measures focuses on the AEV scenario and assesses changes from the BAU set of conditions. We gauge the effectiveness of each mitigation measure in terms of the extent to which it restores shareholder earnings, shareholder ROE, and/or average customer rates to the levels that occur under the BAU case.

³² In particular, we do not look at different customer-sited PV ownership models nor do we analyze how renewable portfolio standard compliance strategies could mitigate utility shareholder and customer impacts (Satchwell et al., 2014). We do not consider value of solar tariffs, non-fuel cost trackers, formula rates, multi-year rate plans, or various other options identified in the literature (Bird et al., 2013; Lowry et al., 2013; Kihm and Kramer, 2014). Lastly, more fundamental changes to the regulatory model (e.g., the introduction of a distribution system operator or major changes in the roles and responsibilities of electric utilities) are not within our scope (Satchwell and Cappers, 2015; Barbose et al., 2016).

³³ In this study, we characterize ratepayer impacts by the change in average all-in retail rates and customer bills. However, we note that ratepayers may be impacted in other important ways. For example, mechanisms that allocate a greater share of risks to ratepayers may result in negative impacts that are not immediately or clearly reflected in customer rates and bills.

Table 7. Regulatory and ratemaking mitigation strategies

Mitigation Measure	Description	Revenue Erosion	Lost Earnings Opportunity	Increased Rates
Revenue-per customer (RPC) decoupling	Revenue decoupling is implemented by setting a revenue per-customer target in rate cases and adjusting rates annually between cases to collect revenues at the target level	●		○
Increased demand & customer charges	An increased share of non-fuel costs is allocated to demand or fixed customer charges	●		○
Shareholder incentives	Utility shareholders receive additional earnings for the successful achievement of policy goals (in this case, related to EE and customer-sited PV deployment)		●	○

● Primary intended target of mitigation measure ○ May exacerbate impacts of EE and customer-sited PV

5.1 Strategies that mitigate the “Revenue Erosion Effect”

The traditional electric utility business model in the United States provides a financial incentive for the utility to increase electricity sales between rate cases, due to a heavy reliance on volumetric energy charges to recover both variable and a sizable portion of fixed costs.³⁴ This is commonly referred to as the “throughput incentive” (Moskovitz, 1989), which is the same as the “revenue erosion effect” described in section 4.6.

Historically several regulatory tools have been used to mitigate utility disincentives to pursue energy efficiency, including various forms of revenue decoupling, lost revenue adjustment mechanisms, and changes to retail rate design. Several of these designs have recently been discussed to mitigate utility concerns regarding adoption of distributed PV (Barbose et al., 2016). Our analysis focuses on a subset of these types of mitigation mechanisms with a design common in the NE region.

We model a **Revenue per customer (RPC) decoupling mechanism** that allows utility revenues to

³⁴ If a majority of both variable and fixed utility non-fuel costs are allocated to rate components based on volumetric sales, then any increase in sales between rate cases should compensate the utility for more than its associated increase in variable non-fuel costs (because there is also a component of non-fuel costs embedded in the rate that is unaffected by changes in sales). Thus collected revenue between rate cases should grow faster than costs resulting in higher achieved earnings for the utility.

change with the current number of customers, rather than utility revenues changing based on retail sales and demand (The Regulatory Assistance Project, 2011). The authorized revenue-per-customer is determined during each general rate case by dividing some or all test year non-fuel costs by the number of customers in the test year. Between rate cases, this authorized revenue-per-customer amount is multiplied by the number of customers in a given year to arrive at total authorized non-fuel revenue. The utility then typically uses a balancing account to collect the difference between actual collected revenue and the authorized total non-fuel revenue under the decoupling mechanism. This balancing account is then applied on a volumetric energy basis to adjust retail rates without any lag to ensure that the full amount of the balancing account is collected in the year that it is calculated. This ensures that the utility fully collects its total authorized non-fuel revenue each year under the decoupling mechanism. Revenue decoupling is common in the NE; five states have approved the mechanism for at least one utility (CT, MA, NY, RI, VT) and it is currently under consideration in two more states (DE and PA). We employ an RPC with current year balancing account design in this analysis as it is a common form of revenue decoupling in the NE (IEI, 2014).

We also model changes to rate design that includes an **increased customer charge**. A customer charge is a fixed fee that does not vary with energy consumption and increases the proportion of utility revenues collected on a per-customer basis relative to revenues collected on the volume of retail sales (Wood et al., 2016). Fixed customer charges have been an ever-present, albeit small, component of retail rate design. However, many electric utilities across the US have recently proposed to increase them either for all customers or some subset of customers with DG. In the first quarter of 2016, 18 states saw proposals for customer charge increases, including three in the northeastern U.S. (Center, 2016). We designed an increased customer charge scenario by changing the share of non-fuel costs allocated to the customer charge in our base retail rate design. We increased the share of non-fuel costs collected via a customer charge from 18% to 75% for the residential customer class and from 11% to 75% for the C&I class.³⁵ We did not change the street lighting customer class rate design, as it collects 93% of non-fuel costs via a customer charge in the BAU case. The six-to nearly seven-fold increase in the customer charge in this analysis represents an upper bound of non-fuel cost allocated to a customer charge. The largest increases to fixed charges that have been recently proposed by utilities roughly doubles the customer charge (Wood et al., 2016). Thus, the scenario is meant to be illustrative of the likely greatest extent to which an increase in the revenue collected via a customer charge can mitigate the revenue erosion effect.

We also model an **increase in demand charges** targeted at C&I customers as well as the introduction of a demand charge for residential customers. A demand charge is a fee for electricity usage during a specified time interval (e.g., one hour) intended to collect utility revenues based on the volume of a customers' contribution to coincident or non-coincident peak demand (i.e., kW). Demand charges are common among large C&I customers and have been in place for many years,

³⁵ Note that in this scenario, we also reduced the volumetric charge for both customer classes such that the total amount of non-fuel costs collected via all charge types did not exceed 100%.

but are uncommon among residential customers. Conceptually, demand charges have been discussed as a means to mitigate the revenue erosion effect (Hledik, 2014). However, at present, only a handful of utilities have proposed some form of residential demand charge. To explore the potential impacts of demand charges, we increase the share of non-fuel costs allocated to a non-coincident monthly demand charge from 0% to 50% for the residential class and from 47% to 75% for the C&I class. Again, such a change in retail rate design is intended to be illustrative and not suggestive of what is reasonable or appropriate.

Rate design approaches to mitigate the revenue erosion effect essentially shift utility revenue from reliance on volumetric energy consumption to customer count or volumetric demand. Thus, the relative growth rate of each billing determinant, before and after the mitigation measure is applied, will drive its effectiveness.³⁶ If customer growth is expected to outpace sales growth after taking into account the effects of EE and PV between rate cases, then the application of an RPC decoupling mechanism or increased reliance on customer charges should increase utility revenue collection, all else being equal. The impact of increased reliance on demand charges likewise can increase utility collected revenues provided demand growth outpaces sales growth between rate cases.

In the AEV case, the utility's collected revenues over the analysis period are 34.3B (20-year PV), which is 1.7B (5%) less than under the BAU. All three mitigation approaches increase the NE utility's collected revenue from customers relative to the AEV case without the mitigation approach (see Figure 12). Specifically, the application of an RPC decoupling mechanism provides the utility with an additional \$803M of revenue on a PV basis over 20 years, which represents an additional 2.2% of revenue in the AEV case. Likewise, increasing the customer charge for residential, C&I customers provides \$568M (1.6%) of additional revenue. The RPC decoupling mechanism provides more collected revenue to the NE utility compared to the increased customer charge, because the RPC decoupling mechanism shifts all non-fuel costs whereas the increased customer charge only allocates a fraction of non-fuel costs. The demand charge scenario also increases utility collected revenue amounts with an additional \$206M (0.6%). From a shareholder perspective, allocating more non-fuel costs to the demand charge is less effective than allocating them to a customer charge, which is unaffected by EE and PV savings levels.

³⁶ If the application of these mitigation measures affects the average all-in retail rate, it is highly likely, as previously alluded to, that this will have a feedback effect on the customer economics (e.g., payback time) of investing in EE and/or rooftop PV which will ultimately impact the likelihood that the EE and PV penetration goals are actually achieved. Quantifying this effect is beyond the scope of this study but has been addressed elsewhere (see Darghouth et al. (2016)).

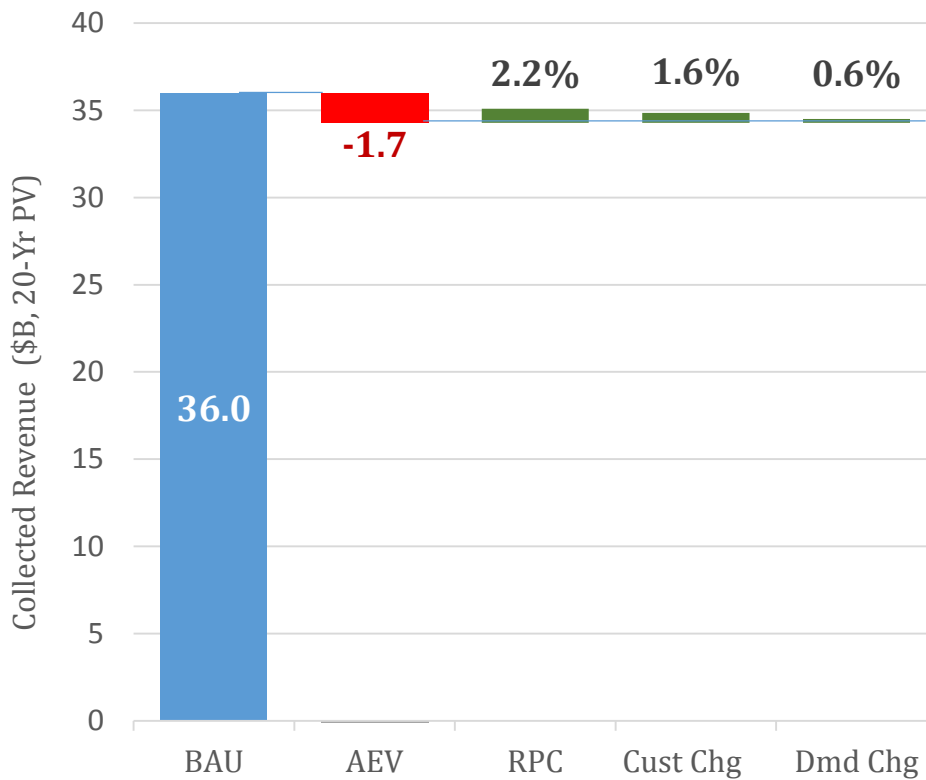


Figure 12. Impact of measures intended to mitigate revenue erosion on collected revenue

We also assess the extent to which the mitigation strategies impact average all-in retail rates. In the AEV scenario, all-in average retail rates are 19.5 cents/kWh over the analysis period, an increase of 3.5 cents/kWh (22%) compared to the BAU case. We expect all-in average retail rates to increase with mitigation measures relative to the AEV case because increased revenues to the utility associated with the mitigation measures is spread over the same sales base (see Figure 13). The introduction of an RPC decoupling mechanism increases all-in average retail rates by 0.5¢/kWh (2.3%) over a 20 year time horizon. If instead the utility increased the share of costs allocated to customer charges, average all-in retail rates would increase by 0.3¢/kWh (1.6%). In this case, a larger fraction of the non-fuel revenue is now tied to customer growth, but not all of it as is the case with an RPC decoupling mechanism. If the demand charge portion of retail rates were increased, 20 year all-in average retail rates would rise by 0.1¢/kWh (0.6%). It is important to note that the increases in average all-in retail rates from the mitigation measures is in addition to average rate increases associated with the aggressive EE and PV scenario results.

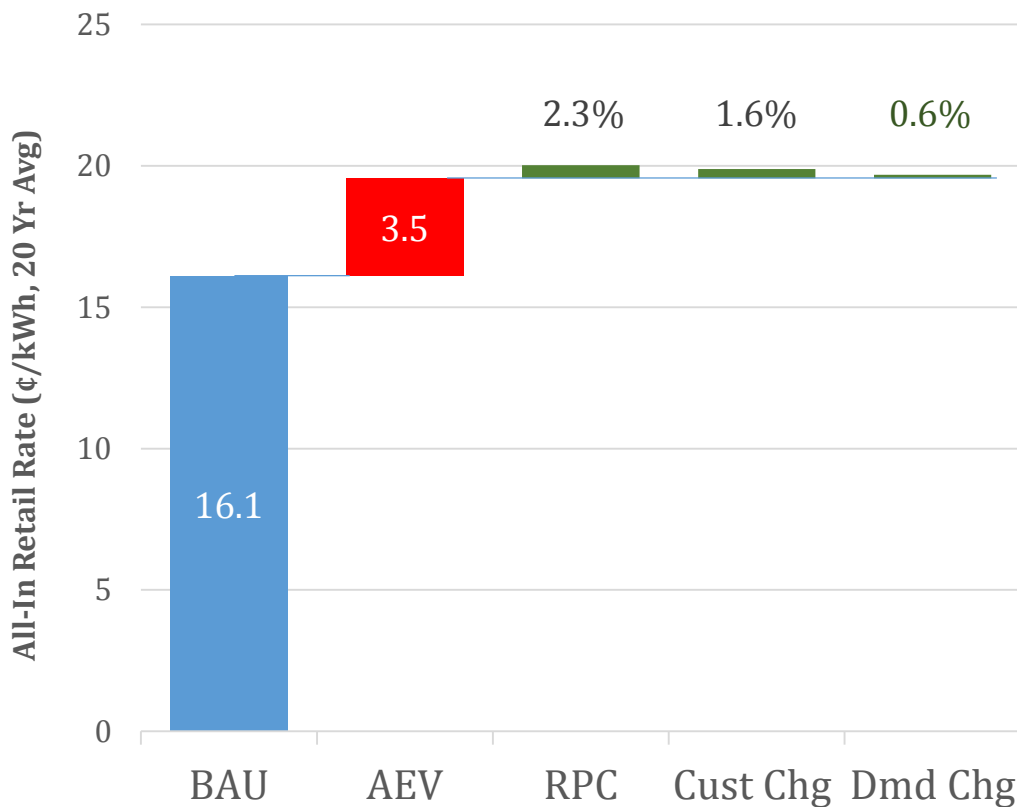


Figure 13. Impacts of revenue erosion mitigation measure on all-in retail rates

Figure 14 shows the increase in the utility’s achieved ROE associated with these three mitigation measures. In an aggressive EE/PV scenario, the utility’s average achieved ROE decreases to 6.2% (see red bar in Figure 14). Applying an RPC decoupling mechanism increases ROE by more than 280 basis points (34% of utility’s achieved average ROE in the BAU scenario), which more than offsets the 200 basis point erosion in ROE in the aggressive EE/PV scenario. Since both changes in retail rate design (i.e., increased customer charge and increased demand charge) had a smaller impact on revenue than RPC decoupling (see Figure 13), it is likewise not surprising that they have a smaller impact on the utility’s achieved ROE. The very high customer charges that we modeled could increase the utility’s achieved ROE by about 200 basis points (24% of utility’s achieved average ROE in the BAU scenario), while very high demand charges would increase the achieved ROE by about 69 basis points (8% of utility’s achieved average ROE in the BAU scenario) in the aggressive EE/PV scenario.

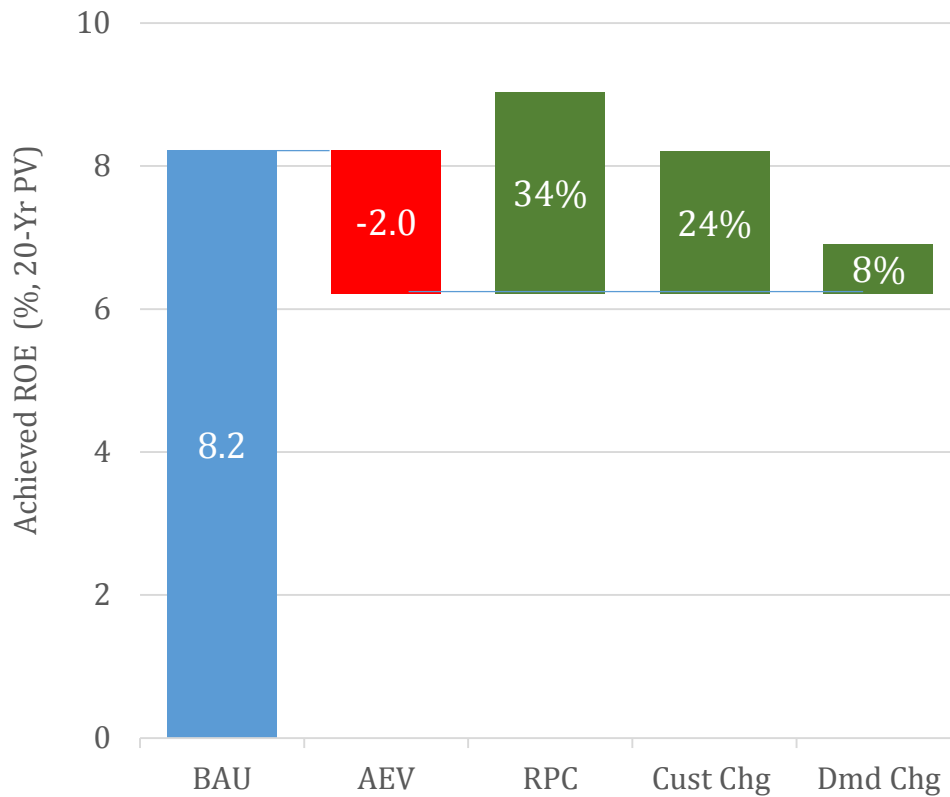


Figure 14. Impacts of revenue erosion mitigation measures on achieved ROE

The designs for the RPC decoupling mechanism as well as retail rates were chosen *a priori* based on common designs observed in the NE region. They were not designed with any knowledge of their contribution to revenues and ultimately ROE. We believe that the achieved ROE is a useful metric to focus on because it normalizes the change in collected revenue by the shareholder equity. We see from Figure 14 that two of the three mitigation measures (i.e., RPC decoupling and higher customer charge rate design), as designed and implemented in this analysis, more than compensate the utility for reductions in its achieved ROE in the aggressive EE/PV scenario.

5.2 Strategies that mitigate “Lost Earnings Opportunities Effect”

Under traditional regulation, EE and distributed PV also erode the utility’s opportunity to generate earnings from incremental capital investments to the extent that they defer or avoid capital expenditures by the utility (i.e., the “lost earnings opportunity effect”) One potential solution is to allow the utility the opportunity to collect additional revenues for successful achievement of energy savings goals from EE and/or customer-sited PV, thereby creating positive earnings opportunities for the utility.

Shareholder incentive mechanisms for EE have been used in many forms over the past two decades (NAPEE, 2007). Depending on their specific design, shareholder incentive mechanisms may encourage utilities to meet or exceed energy savings targets (e.g. performance bonus), to invest shareholder funds in EE programs (e.g. cost capitalization programs), or to pursue efficiency options that produce the greatest net benefit (e.g., shared net benefits). Shareholder incentives for EE have generally been implemented in conjunction with utility-administered EE programs although several states with third party administration of energy efficiency (e.g., VT, HI) have offered moderate incentives for successful accomplishment of efficiency goals (Cappers et al., 2009).³⁷

The customer-sited PV market has been dominated almost exclusively by third-party entities. As policymakers and regulators have set goals for distributed PV and offered financial incentives or attractive rates (e.g., net metering) to encourage PV, utilities have not been directly compensated for the foregone capital investment due to the success of such activities. Given this history, we do not model any type of financial incentive that inures to the utility for successful achievement of PV goals because at least as of the time this research was performed, investor-owned utilities in the Northeast were predominantly not in the customer-sited solar business and did not receive any financial compensation for successful achievement of solar penetration goals by third-party providers.

However, we model a case in which the NE utility owns a portion of distributed PV systems, thereby earning its authorized rate of return on the investment. Allowing customer-sited PV to become a regulated investment opportunity for utilities may involve full utility ownership of customer-sited PV assets, as recently proposed by utilities in the Southwest (e.g., Arizona Public Service and Tucson Electric Power) or may consist of utility financing of customer investments, similar to Public Service Electric and Gas (PSE&G)'s Solar Loan Program.³⁸ Utility ownership or financing of customer-sited PV may raise a variety of significant policy and regulatory questions, including whether a regulated utility should be allowed to provide a service similar to that provided by unregulated, private sector companies. Moreover, in some states that have restructured, regulators no longer allow investor-owned utilities to own generation (as in our NE utility), in which case utility ownership of customer-sited generation may be prohibited or would require special authorization.³⁹

³⁷ In many states that have moved toward 3rd party administration of EE programs, state regulators have implemented a decoupling mechanism for utilities (e.g., Vermont, Hawaii, Oregon) but have not mitigated utility lost earnings opportunities in part because the utility is not directly or ultimately responsible for the successful achievement of EE savings goals by third-party administrators.

³⁸ Under the PSE&G Solar Loan program, the regulated utility provides loans to residential and commercial customers to purchase PV systems (which are net-metered), and the utility is allowed to add the cost of the program to its ratebase.

³⁹ See Wiser et al. (2011) for examples of utility ownership of customer-sited PV, including the MA Green Communities Act of 2008, which allows the state's regulated electric distribution companies to construct, own, and operate up to 50 MW of solar generation each.

Putting aside those important policy questions, we assume for the purpose of our analysis that the regulated utility is allowed to own customer-sited PV⁴⁰ and earn its authorized rate of return on those assets. Prior quantitative analysis of such a case by the authors (Satchwell et al., 2014) included two scenarios: one in which the utility owns 100% of customer-sited PV capacity in their service territories, and another in which it owns 10% of PV capacity.⁴¹ In this analysis, we only model a 10% ownership case as it is the more likely scenario to evolve in the Northeast over our analysis time horizon, given the current policy environment. The utility is assumed to receive additional revenues from customers with PV systems that are owned or financed by the utility, and those revenues are assumed to be sufficient to provide the utility both a return *of* and *on* its investment. We assume that this investment in distributed PV is amortized over its assumed useful lifetime (i.e., 20-years in this analysis) and financed at the utility's regulated capital structure, which means that the utility earns a return on the equity portion of the investment. Thus, the shareholder incentives modeled are granted to the utility for the successful achievement of energy savings goals as well as partial achievement of PV savings goals. Specifically, we assume that the utility is authorized to collect a shareholder incentive that is equal to 10% of the annual EE program administration cost, where these additional revenues go directly to utility earnings. We also assume that regulators allow the utility to own 10% of the installed PV capacity.

We focus on the impacts to shareholder ROE and earnings over the full 20-year analysis period, given that the lost earnings opportunities associated with EE and PV occur over the lifetime of these resources and particularly in the latter years of the analysis period. Therefore, the effect of the shareholder incentive mechanisms should be quantified over a comparable time period to fully capture their contribution to offset the foregone earnings opportunity.

As shown in Figure 15, implementation of the modeled shareholder incentive mechanisms increase the utility's collected revenue by \$136M on a present value basis over 20-years (0.4%). This translates into an additional \$81M (5%) of earnings on a present value basis, as depicted in Figure 16. The increase in collected revenues and subsequent increase in earnings reflects both the additional revenues from the EE shareholder incentive mechanism and the return on the equity portion of the utility owned distributed PV.⁴² It is important to note that the extent of revenue and

⁴⁰ We assume that customer-sited PV costs \$2.41/W^{dc} in 2017 for residential systems and \$2.1/W^{dc} in 2017 for non-residential systems (Fu et al, 2016). These costs reflect all module and installation costs except the installer's profit margin. We specifically exclude the profit margin because that is calculated separately in the FINDER model based on the utility's authorized rate of return and capital structure. We also assume that the utility is able to take advantage of the federal investment tax credit (ITC) for installations as would be the case for systems owned by any commercial entity, including a regulated utility. We model the incremental impacts of ratebasing the distributed PV systems on utility shareholders and, therefore, do not take into account any effects of tax normalization.

⁴¹ Distributed PV systems are assumed to be installed behind the customer-meter and interconnected via a standard net metering arrangement; thus the impacts on utility billing determinants under this mitigation scenario are the same as in the AEV case.

⁴² Because these incentive amounts are collected via an annual balancing account mechanism, they are contemporaneously reflected in the utility's earnings.

earnings gains are a function of the design of the modeled shareholder incentive mechanism, where greater or lesser increases in earnings could be achieved simply by increasing or decreasing the specified share of program administration costs offered as a bonus or the portion of PV capacity owned by the utility.⁴³

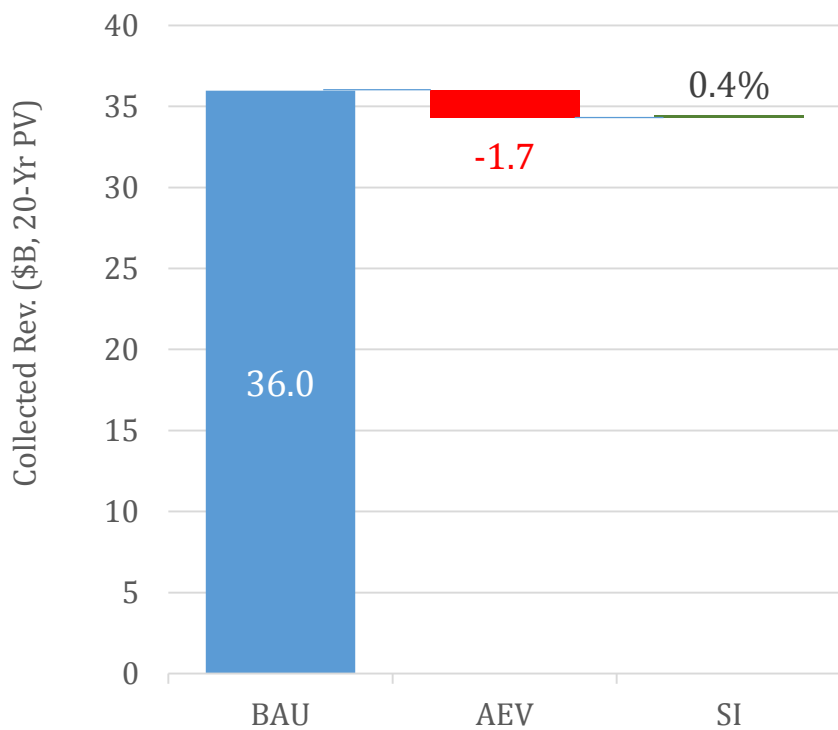


Figure 15. Impacts of shareholder incentives on collected revenue

⁴³ This analysis focuses solely on change in achieved utility earnings as the metric around which shareholder incentive mechanisms are designed. This concentration on shareholder returns may not be comprehensive enough to assess whether a shareholder incentive mechanism would produce the regulator’s desired outcomes. Investment risk, scale, and return are key variables to consider when comparing alternative investments and may suggest other shareholder incentive designs that better maintain shareholder value in the face of reduced future earnings opportunities (Kihm et al., 2016).

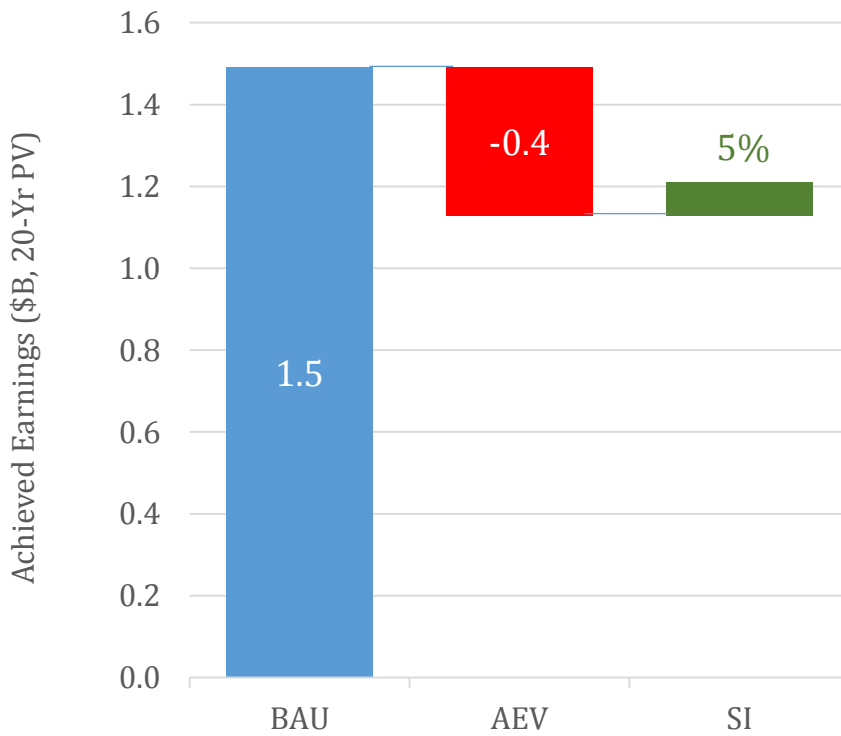


Figure 16. Impact of shareholder incentives on achieved earnings

We do not present quantitative results for changes in average retail rates. Qualitatively, we know that any increase in achieved earnings associated with a shareholder incentive mechanism will by definition result in an increase in average retail rates relative to the AEV scenario, all else being equal. Such an increase in average retail rates would most likely be related to the EE shareholder incentive as any additional costs from the utility PV ownership would be passed through to the PV customers only.⁴⁴

Thus, shareholder incentive mechanisms present a similar tradeoff for policymakers that are trying to align and balance public policy goals: increased earnings to shareholders which cause somewhat higher rates for customers.

⁴⁴ We do not present rate impacts as the incremental changes to average rate impacts for the utility PV ownership mitigation case are assumed to fall solely on PV customers. Thus changes to average rates for *all* customers (which is what the FINDER model estimates) are not a meaningful measure.

6 Participant and Non-Participant Bill Impacts

From the customer's perspective, an investment in energy efficiency or solar PV reduces utility bills by lowering the quantity of electricity consumed. Customer bill savings are an important economic driver for EE and PV adoption as they are a key determinant of EE measure and PV system payback times.

Regulators and policymakers are also concerned about potential increases in retail rates from high penetrations of EE and distributed PV which may adversely affect customers that do not invest in PV systems or EE measures (i.e., non-participants) more than customers that do (i.e., participants). This potential cost shifting effect has made some regulators and policymakers hesitant to increase ratepayer-funded EE program budgets or support policies for greater distributed generation penetration (e.g., net energy metering arrangements). Therefore, analyzing and understanding changes in customer bills can address a key barrier to expanding EE and DG activities (SEEAAction, 2011).

Moreover, analyzing bill impacts on participating and non-participating customers illustrates how the outcomes of achieving broader societal goals may vary among distinct groups of customers. In addition to assessing net benefits of clean energy policies, policymakers and regulators are also concerned about the distributional effects of existing and alternative ratemaking and regulatory approaches on different groups of customers.

A number of studies have looked at the impacts of energy efficiency or solar PV on participant and non-participant bills, but never jointly. Several studies have examined customer bills under net energy metering (NEM) compensation mechanisms for solar PV as compared to other compensation mechanisms for exported generation (e.g., feed-in-tariff, wholesale energy market prices). These studies primarily focus on residential customers and are based on state-specific rates and policies (e.g., Darghouth et al., 2011; Darghouth et al., 2013). Woolf (2013) analyzed customer bill impacts among EE participating customers with quantitative examples illustrating foundational concepts. However, the existing studies on bill impacts of energy efficiency programs focus on short-time horizons (e.g., 3-5 years) and either disregard entirely or assume a very simple and static feedback effect between changes to billing determinants (e.g., lower retail sales) and changes in retail rates.

This analysis builds on the financial impacts assessed in sections 4 and 5 of this report that summarized the NE utility's collected revenues in the BAU and AEV cases but did not break out results for participants and non-participants or consider the impacts on customers' timing of investments in EE and PV in the BAU and AEV scenarios. For example, customers with different initial energy and peak demand levels may experience different bill impacts, regardless of their decision to invest or not. Customers who chose to invest early versus those who invest later in the analysis period may also see varying bill impacts. The choice of investment itself (e.g., EE vs. PV)

also plays a pivotal role in the magnitude of bill reductions. Finally, regulatory and ratemaking strategies that are intended to mitigate the effect of declining sales on a utility's ability to fully recover its fixed costs (e.g. increased reliance on customer or demand charges) may have varying bill impacts across these customer subpopulations.

This analysis uses the annual class-level retail rates for energy (¢/kWh), demand (\$/kW), customer (\$/customer), and balancing accounts (¢/kWh) derived in sections 4 and 5 as the basis for a customer bill analysis. Our goal is to quantify the diversity of impacts on the present value of annual electric bills during the ten year analysis period (2017-2026) based on a customer's decision whether or not to invest in energy efficiency or solar PV.⁴⁵

6.1 Analytical approach

We develop an analytical approach intended to be illustrative of the range of potential customer bill impacts. We do not model the entire population of customers for the NE Utility but instead develop representative characterizations of sub-populations of customers that are likely to participate in several types of EE programs or invest in PV systems.

We create sub-populations of customers based on their usage profiles relative to the class average that are eligible to participate in a single EE program (e.g., commercial rebate program targeted at smaller business/industrial customers, custom rebate program targeted at large C&I customers, residential low-income program, residential consumer product rebate program) or install a PV system (see Figure 17 and Figure 18).⁴⁶ Each subpopulation's unique EE or PV investment generates average annual energy and billing demand savings expressed as a percent of usage for the class average customer. For example, we assume that the typical low-income residential customer of the NE utility uses less electricity than the average of all residential customers. To more accurately characterize bill impacts of participating in a low-income program, we assume that the typical low-income residential customer that is eligible to participate in a low-income EE program consumes 83% of the residential class average as their baseline and reduces their annual energy and system coincident demand level by 10% based on the measures installed in that program. Similarly, we assume that all residential customers eligible to participate in an EE product rebate program (e.g., lighting measures such as CFL or LED) have an initial usage level that is comparable to the class average and reduce their annual energy and peak demand by 2.3% based on measures installed in that program. For residential customers that have the potential to install a solar PV system, we assume that it is sized to reduce their annual energy usage by 100% but does not affect their system coincident billing demand (Darghouth et al., 2017). However, we assume that participation in a specific EE program or investment in a solar PV system is mutually

⁴⁵ We chose to calculate customer bills from 2017 to 2026 because it represents the period in which customers are making EE and PV investments.

⁴⁶ This is a simplifying assumption that allows us to illustrate and isolate the impacts of participation decisions to invest in specific EE or PV technologies. Clearly, customers of various sizes may invest in both PV and undertake EE measures.

exclusive and independent. In other words, a participating customer only has the option of investing in EE measures offered in a specific EE program or installing a PV system.

Annual energy and demand savings for the illustrative EE programs and PV systems come from several sources. We primarily relied on the Massachusetts' EE program administrator 2014 and 2015 reports for program savings. We also reviewed the 2009 residential energy consumption survey (RECS), which was the most recently available dataset, to estimate average low-income energy consumption across the northeast region (EIA 2009). PV system savings were assumed at 100% of the class-average residential customer's annual energy due to the fact that net-metering arrangements incentivize solar systems to offset annual energy use, though we acknowledge this is an upper-bound assumption as many jurisdictions do not allow customers to size PV systems to exceed average annual energy consumption. C&I PV system energy savings are from Davidson et al. (2015) that calculates average C&I system size based on available roof space and other assumptions. PV system demand savings come from Darghouth et al. (2017) simulating the PV system profiles and their coincidence with utility system peak.

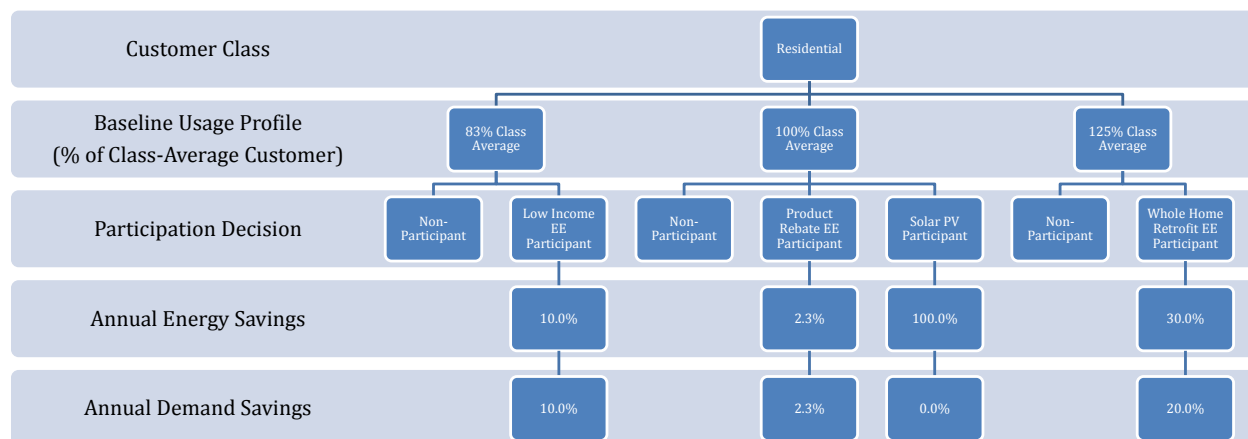


Figure 17. Participant & non-participant customer sub-population characteristics: Residential class

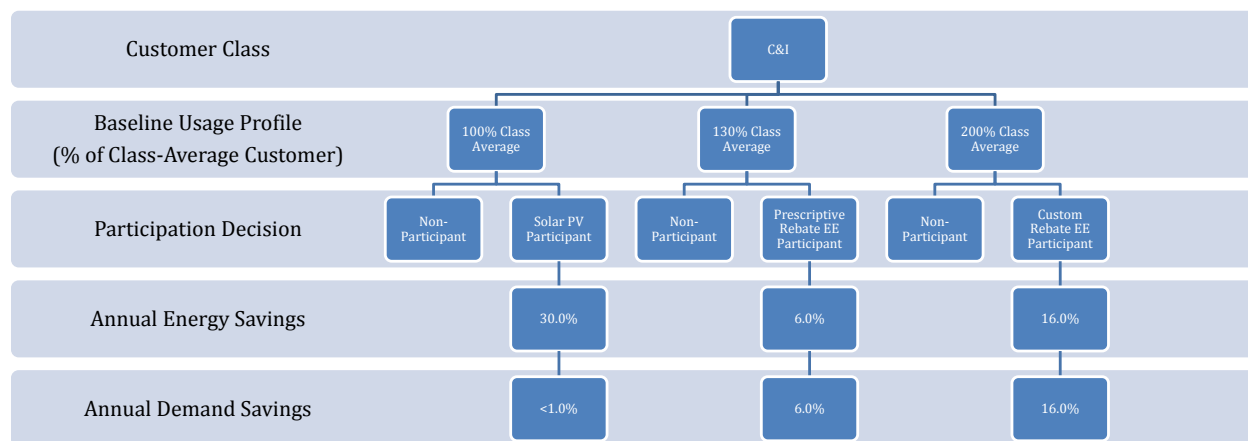


Figure 18. Participant & non-participant customer sub-population characteristics: C&I class

In addition, the timing of when an EE or PV investment is made matters for calculating customer bills as the annual retail rate increases are greater in later years of the analysis period due to the cumulative EE and PV portfolio effects. To illustrate the timing element, we differentiate customers based on when this participation decision is made to meet the incremental AEV savings goals, as follows:

- **Non-Participant:** A customer that did not invest in EE or PV prior to the start of our analysis period, and also chose not to participate during the analysis period in either the BAU or AEV scenarios;
- **Prior Participant:** A customer who invested in EE or PV prior to the start of our analysis period (2017-2026) and does not make any additional subsequent investments during the analysis period; and
- **New Participant:** A customer who invested in EE measures through a utility program or PV system at some point during the analysis period in the AEV scenario.

We assume that annual energy and demand savings from the EE programs and PV systems persist at the same level after the investment is made through the remainder of the analysis period. Conceptually, this means that we are assuming that the prototypical NE utility is achieving its aggregate savings goals over time by simply reaching more customers in that class rather than achieving deeper savings on a per customer basis over time.

Figure 19 shows the methodology to calculate annual bills for these different cohorts of customers based on the timing and impact of their investment decisions. Specifically, customer bills for each of the customer subpopulations are derived annually by multiplying each rate component (i.e., ¢/kWh, \$/kW, and \$/customer) by its respective billing determinant (i.e., per customer annual kWh retail sales, per customer annual kW peak demand) where the total utility bill reflects the sum of all revenue collected via base rates and balancing accounts (see Figure 19). For both residential and C&I customers classes, although not explicitly shown, balancing account costs are collected via an energy charge and included in the energy portion of a customer's annual bill. It is important to note that we assume all customers within a rate class (e.g., residential customers) face the same retail rates, regardless of participation in an EE or PV program. For participating PV customers, we assume a net-energy metering (NEM) compensation policy is in place that allows annual net metering credits from excess PV production to offset an equal amount of annual energy consumption with no carryover from one year to the next.

Our approach illustrates the diversity in bill impacts over time as compared to simply assuming a single class-average customer who chooses whether or not to invest in EE or PV at a single point in time during our analysis period. By keeping the savings percentage on a per customer basis for specific EE and PV investments static over time, we can more accurately quantify the impact of rate changes over time on both participants' and non-participants' bills due to the impact on utility costs of achieving higher aggregate EE savings goals and PV market penetration.

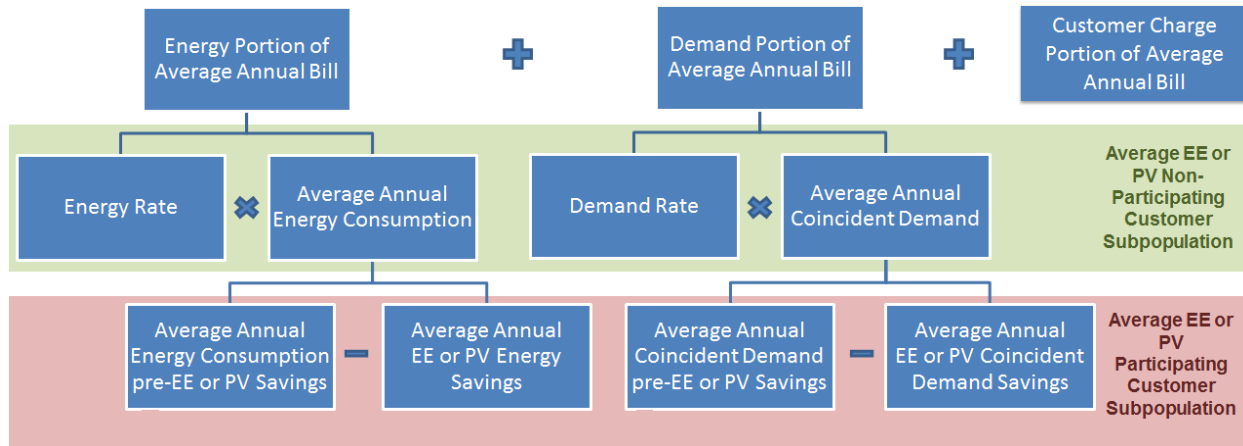


Figure 19. Bill calculation methodology for program participants and non-participants

6.2 Impacts on participants and non-participants

For each of the customer sub-populations that are eligible to participate in the selected EE programs or can install PV systems, it is important to understand the basis of comparison for any bill metrics that will be reported, as their participation status with respect to time and scenario matters, as follows:

- **Non-Participants** – These customers do not invest in EE or PV during the analysis period. Thus, we calculate bill impacts using the difference in rates in the BAU and AEV scenario, holding annual energy and demand constant. Results for non-participants, therefore, represent the effects of rate increases associated with the achievement of the AEV savings goals.
- **Prior Participants** – We calculate bill impacts as the difference between bills under AEV scenario rates with and without annual energy and demand reductions attributable to the prior investment in EE or PV. Results for prior participants represents the combined effect of retail rate increases associated with the achievement of AEV savings goals and reductions in customer consumption from existing EE or PV investments.
- **New Participants** – We calculate the bill impacts as the difference in utility bills in the BAU vs. AEV scenario accounting for energy and demand savings that result from EE or PV investments and changes in rates between BAU and AEV case. Results for new participants represent the effect of the decision to make an EE or PV investment during the analysis period.

Non-participants see their bills increase, relative to bills that would have occurred under the BAU scenario, by 16% on a present value basis over the course of the 10 year analysis period (see Figure 20).⁴⁷

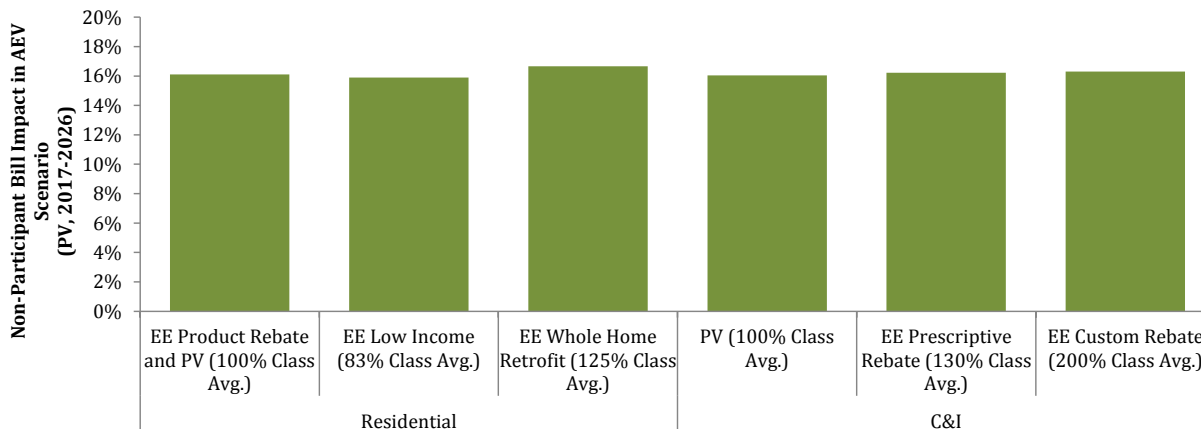


Figure 20. Non-participant bill impacts in AEV scenario

Prior participants experience bill savings that are driven by their prior EE and PV investments (see Figure 21). Those customers that already invested in energy efficiency measures see smaller bill savings (i.e., between 2 and 29% for residential and between 6 and 15% for C&I) than those customers who invested in solar PV systems (i.e., 95% for residential and 25% for C&I). Such prior investments provide a hedge against the rate increases that occur in the AEV case. Because the EE programs elicit more modest savings, they provide a smaller hedge than solar PV, which covers 100% of residential customer’s annual usage and 30% of C&I customer’s annual usage. The larger bill savings from PV investments are due to the way PV systems under a net-metering arrangement are designed to meet as much of a customer’s annual energy use as possible.⁴⁸

⁴⁷ We observe little difference in bills among non-participating customers that are eligible to participate in various EE programs and whose initial consumption levels are characterized relative to residential and C&I class averages (e.g. low income customers whose usage is 83% of residential class average or large C&I customers eligible for custom rebate program whose initial usage is 200% of C&I class average). This is because rates are designed to be revenue neutral to the class average customer and we are scaling energy and demand by the same amount, thus maintaining similar ratios relative to class average.

⁴⁸ C&I customer PV systems cover a small proportion of annual energy use than residential customer PV systems because C&I customer sites are limited by the amount of available rooftop space.

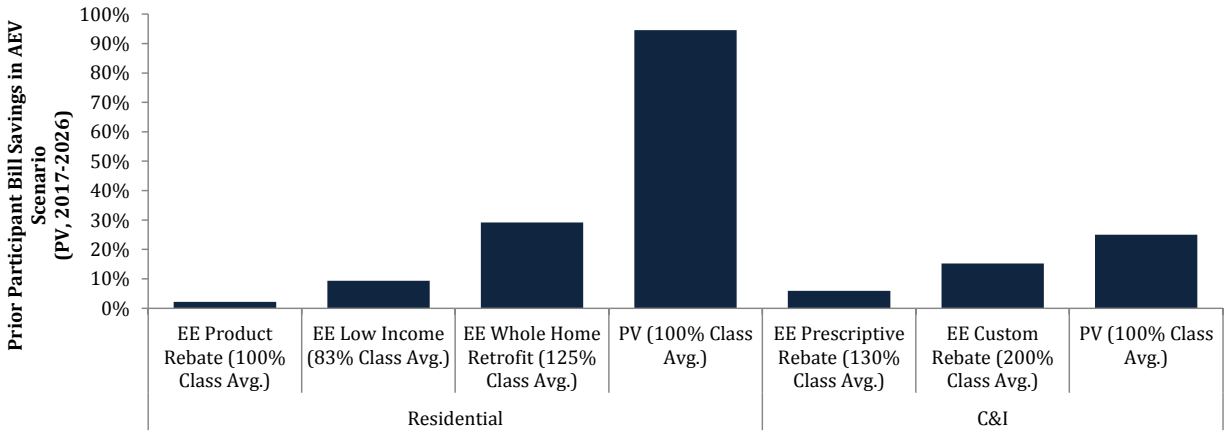


Figure 21. Prior participant bill savings in the AEV scenario

New participants make investments in EE measures through the utility program or invest in PV systems with the expectation that they will experience bill savings relative to their bills in the BAU case. However, new participants are also exposed to and face the increases in rates that occur in the AEV scenario. Given that new participants are investing in EE or PV at some point in the analysis period, it is important to understand how the timing of when such investments occur within the 10 year analysis period affects changes in their aggregate electric utility bills. To do this, we quantify the present value of different 10 year streams of annual bills (2017-2026). The basis of comparison is always the present value of the 10 year stream of a particular customer’s annual bills in the BAU scenario absent any investment in EE or PV. Then, we calculate the present value of different 10 year streams of annual bills in the AEV scenario based on the year when that customer chose to participate in selected utility EE programs (e.g., low-income, residential product rebate, C&I custom or prescriptive rebate) or made a PV investment. By comparing the present value of a 10 year stream of annual bills in the BAU scenario with the present value of a 10 year stream of annual bills in the AEV scenario, we are able to not only see the impacts of the higher rates associated with the AEV scenario but also how the timing of when an EE or PV investment is made affects a customer’s aggregate bills over time.

This comparison is made using heat maps in Figure 22 and Figure 23. The years that are color coded in green imply that EE or PV investments undertaken in the year shown of the AEV scenario by a new participant result in a lower present value of customer bills over the entire 10 year analysis period compared to the present value of customers over the entire 10 year analysis period in the BAU case. Alternatively, years in red show results where the 10-year present value of customer bills are higher in the AEV scenario compared to the BAU case when the investment in EE or PV is made in that year. Entries in yellow indicate that an investment in EE or PV in that given year in the AEV scenario produce a 10-year present value of bills that are comparable to the 10-year present value of bills in the BAU case.

For example, to meet the utility’s PV goals in the AEV scenario, more and more residential customers must invest in a solar PV system each year. If a residential customer invests in a PV system in 2018 (assuming their usage is at the class average level), their entire load is only exposed to the higher rates in 2017. In the later years of the analysis period (2018 to 2026), this residential customer with a PV system faces increasing rates but their utility bill will be very low due to the sizing of the residential PV system (i.e., assumed to be 100% of annual retail sales) and the application of net-energy metering. This results in a net reduction of ~80% in the 10 year present value of their utility bills. If the customer chooses to install a PV system much later in the analysis period (e.g., 2026), their entire load is exposed to the higher rates under the AEV scenario in all but the last year of the analysis period. In that case, the bill savings in 2026 nearly offsets the bill increases that occur in the nine previous years from the higher AEV scenario rates, but bill savings are less than if the customer invested in the PV system earlier.

With respect to residential Product Rebate and Low-Income EE programs, the annual energy and demand savings are too small to keep pace with the rate increases, regardless of when the investment is made. The same is true for Prescriptive Rebate EE programs on the C&I side. Thus, residential customers participating in these types of EE programs will see higher bills in the AEV scenario compared to the BAU scenario regardless of when they chose to invest during the analysis period (early or late). In contrast, participants in Whole Home Retrofit program that invest prior to 2023 or C&I Custom Rebate program participants that invest prior to 2018 see lower aggregate bills in the AEV scenario compared to the BAU case.

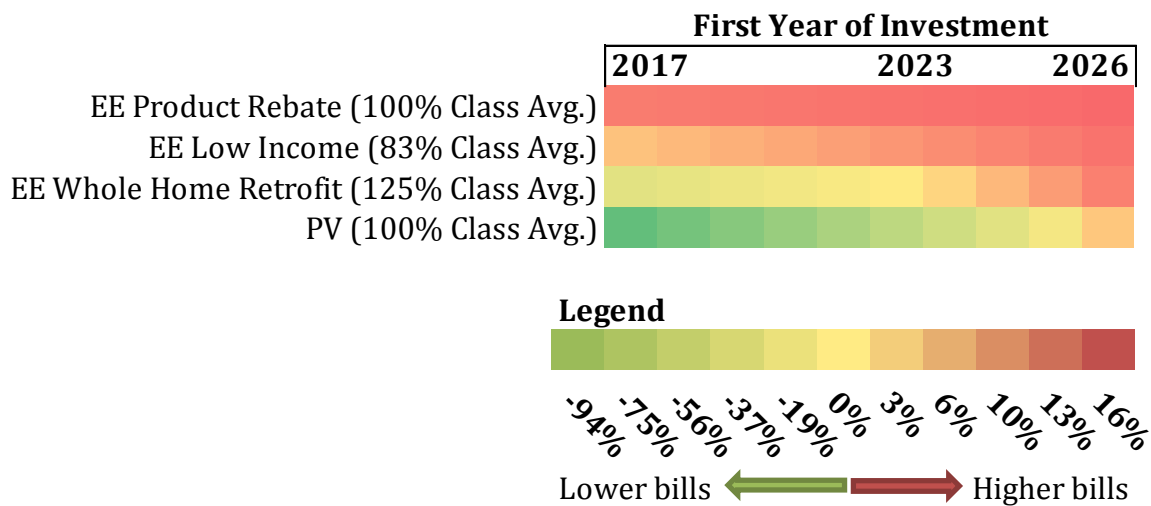


Figure 22. Residential new participant bill impacts in AEV scenario

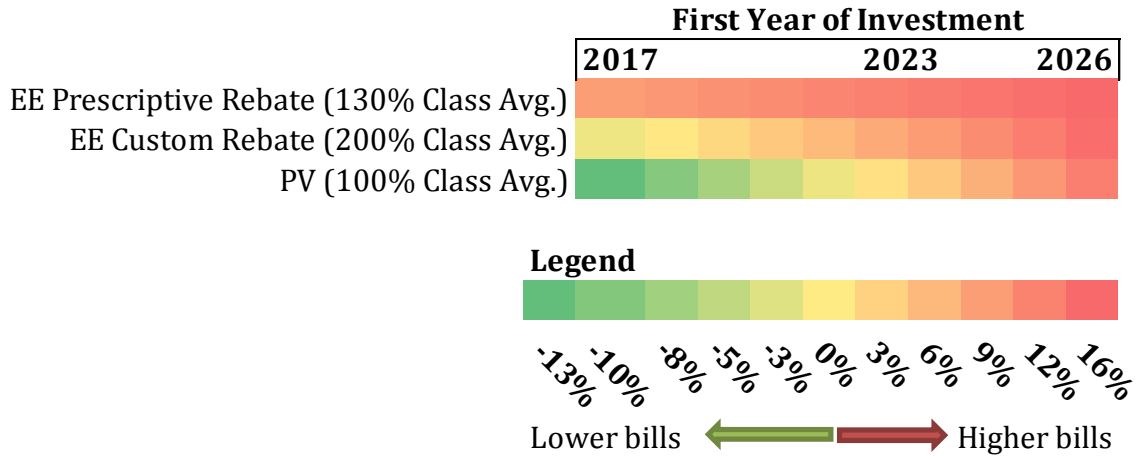


Figure 23. C&I new participant bill impacts in AEV scenario

6.3 Impacts of greater reliance on demand charges

One ratemaking approach that the utility could undertake to mitigate the revenue erosion effect that occurs in the AEV scenario is to shift revenue collection away from volumetric energy charges to volumetric demand charges. In our analysis, adding a residential demand charge and increasing the C&I demand charge collect more revenue, thus resulting in higher total customer bills. By applying this new rate design in the AEV scenario, we can assess changes in electric utility bills for different customer groups (non-participants, prior participants and new participants) facing higher demand charges. Our goal is to understand who is affected and better understand why they are affected.

For Non-participants that are eligible for various EE programs, the change in rate design has a very modest impact on their 10-year stream of annual bills (see Figure 24) – slightly positive in the case of residential customers and slightly negative in the case of C&I customers. Not surprisingly, these customers still face higher bills. Retail rates are designed to be revenue neutral to the class-average customer in this study. Because all non-participating customers are scaled up or down from the class-average with respect to both energy and demand, the impact of greater reliance on demand charges have very minor effects on the size of their bill impacts in the AEV scenario.

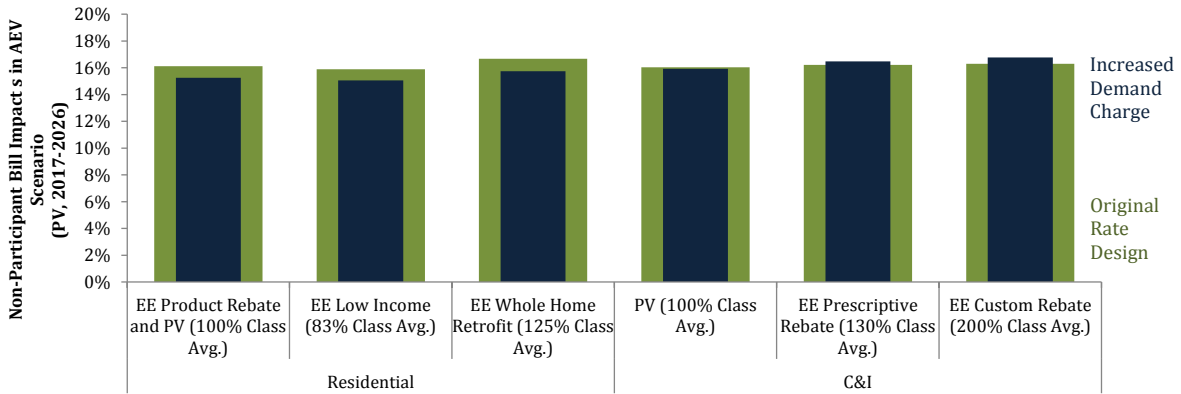


Figure 24. Non-participant bill impacts in the AEV scenario under existing and alternative rate design (increased demand charge)

Prior participants that invested in EE measures through utility programs experience little change in bill savings under a demand charge rate design. In this illustrative analysis, we assume that EE programs produce comparable energy and demand impacts on a percentage basis (see Figure 17 and Figure 18). Thus, a movement towards greater reliance on demand charges should have virtually no impact on bill savings that inures from the investment in such EE measures. In contrast, prior participants with PV systems see a relatively larger change in customer bills (see Figure 25). PV systems, which typically have peak production at times different from customer peaks, do not reduce customer demand nearly as much as energy. This creates an erosion of bill savings equal to 20% for residential PV customers and 9% for C&I PV customers in the AEV scenario under a demand charge rate design.

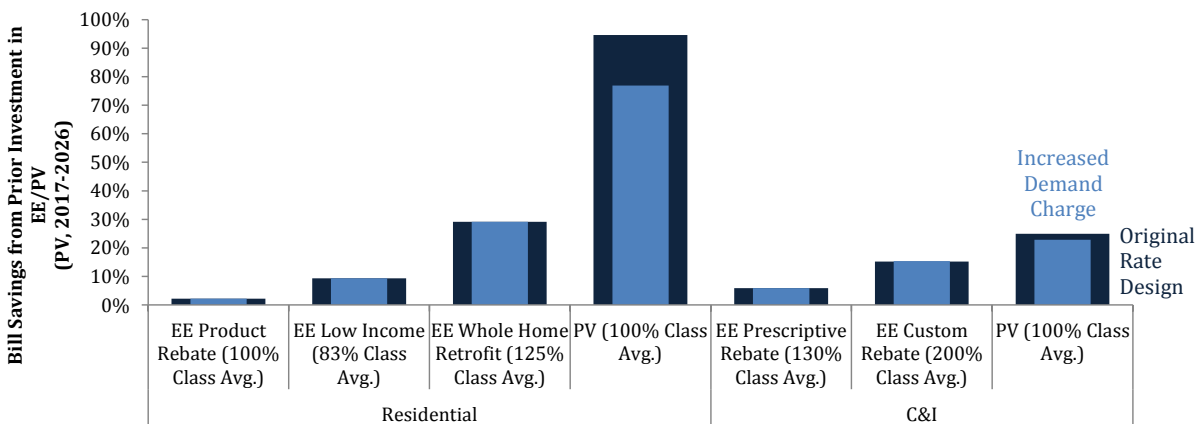


Figure 25. Prior participant bill savings in the AEV scenario under existing and alternative rate designs (increased demand charge)

A demand charge rate design also changes the magnitude and timing of new EE and PV investment decisions. For new participants, the savings associated with residential Product Rebate, Low

Income and C&I Prescriptive Rebate EE programs are modest and do not offset the rising retail rates, even when those rates rely more heavily on demand charges (see Figure 26 and Figure 27). C&I customers participating in the Custom Rebate EE program and residential customers participating in the Whole Home Retrofit program under higher demand charge would see later investments achieve slightly lower utility bills compared to the original rate design.

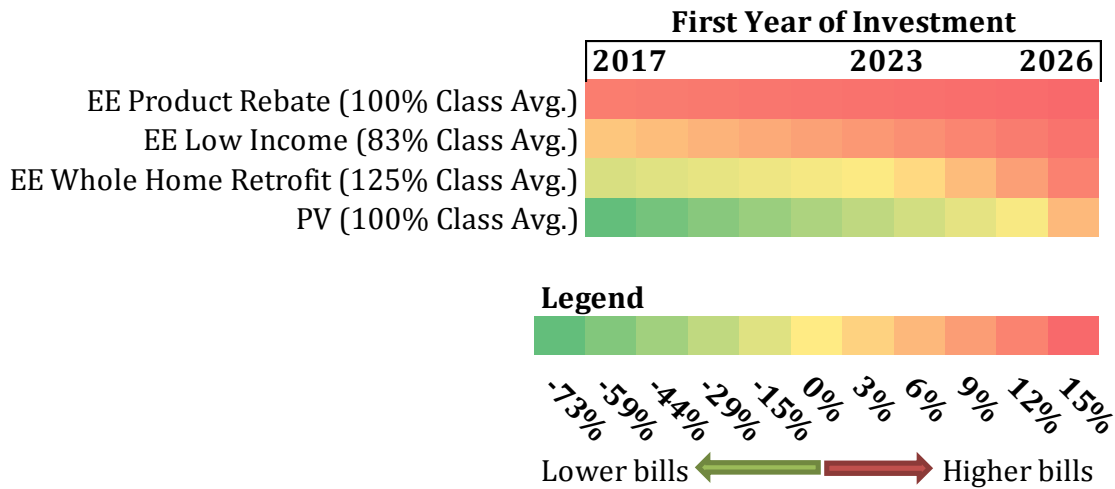


Figure 26. Bill impacts for new participants in residential EE and PV programs in the AEV scenario under alternative rate design

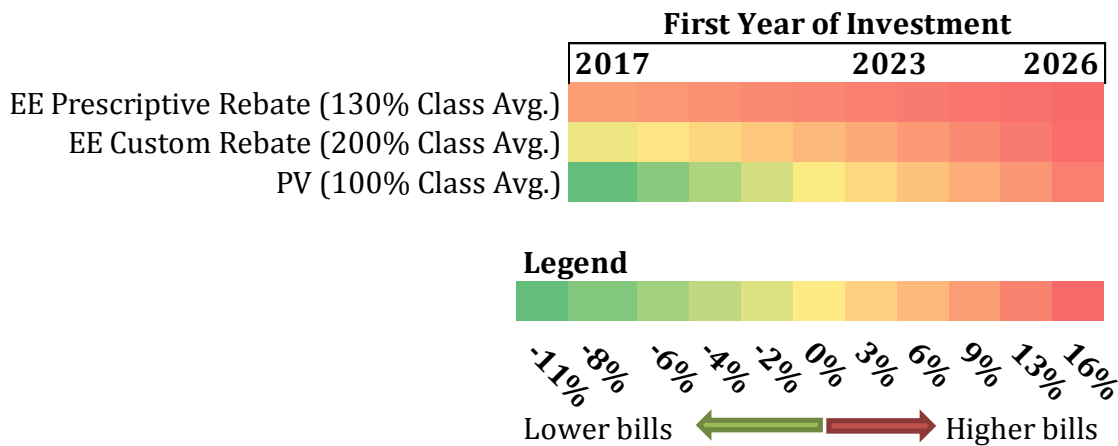


Figure 27. Bill impacts for new participants in C&I EE and PV programs under alternative rate design

7 Conclusions and Areas for Future Research

This analysis relied upon a pro forma financial model to quantify the potential impacts of a combined portfolio of aggressive EE and net-metered distributed PV savings on a NE wires-only utility. We modeled impacts of the aggressive EE and distributed PV portfolios over 20 years and estimated changes in the NE utility's costs, revenues, achieved shareholder earnings and ROE, customer average all-in retail rates, and customer bills. We also analyzed participant and non-participant customer bills, including the diversity of bill savings depending on the type of EE or PV investment.

This analysis makes several important findings about the financial impacts of aggressive EE and PV on utility shareholders and ratepayers. First, an aggressive portfolio of EE and distributed PV puts downward pressure on utility retail sales, which, in turn, significantly reduces the utility's collected revenue. Specific to the NE utility characterized in this study, the combined EE and PV portfolio (i.e., AEV scenario) reduced collected revenues by \$1.7B (5%) over 20 years on a present-value basis. As a result, shareholders may experience significant erosion in earnings and ROE (i.e., 24% lower) as modeled in this analysis. We also found that ratepayers would see material increases in average-all-in retail rates in the AEV scenario (i.e., a 22% increase in average rates over 20 years that translates into an annual rate increase of 3% per year compared to an annual growth rate of 2% in the BAU scenario). This occurs primarily because the remaining NE utility costs are spread over a much smaller sales base, inclusive of the effects of EE and PV on the utility's revenue requirement.

However, the key drivers of the reductions in collected revenues, achieved earnings and ROE, and average all-in retail rates are dependent upon the specifics of the utility. In our BAU case, the NE utility was forecasting slightly negative sales growth and modest demand growth. The aggressive EE and PV savings further reduced the sales and demand growth, such that both declined over the 20-year analysis period. The NE utility's underlying retail rate design relied heavily on volumetric sales for revenue collection. Thus, the decline in retail sales and demand in the AEV scenario drove the reduction in collected revenues. The NE utility is a wires-only utility with a relatively smaller ratebase. Thus, the NE utility did not see as much lost future earnings opportunities because it does not own generation or transmission assets. However, the aggressive savings and PV market penetration in the AEV scenario did not reduce the NE utility's projected non-fuel costs (e.g., defer or avoid distribution system capital investments) by much.

These financial impacts at the utility level and across all customer class are directionally consistent with prior LBNL studies that looked at the impact of EE savings targets or PV policies in isolation (Cappers and Goldman, 2009a; Cappers et al., 2009; Cappers et al., 2010; Satchwell et al., 2011; Satchwell et al., 2014), though impacts on utility earnings and customer rates are much greater in magnitude due to the combined effects of aggressive EE and PV. The significantly larger shareholder and ratepayer impacts primarily reflect how the aggressive EE and PV savings levels

reduce utility revenues by a much greater amount than utility costs – particularly, non-fuel revenues and non-fuel costs.

Our analysis also shows that a variety of measures that constitute arguably “incremental” changes to utility business or regulatory models could be deployed to mitigate the impacts of customer-sited PV and EE on utility shareholders. The analysis of mitigation measures also supports prior findings that design matters. Mechanisms intended to mitigate the revenue erosion effect differ greatly in their design by either shifting utility revenue collection away from volumetric retail sales to customer counts or customer demand. In an aggressive EE/PV scenario, the utility’s average achieved ROE decreases to 6.2%. Applying an RPC decoupling mechanism increases ROE by more than 280 basis points, which more than offsets the erosion in ROE in the aggressive EE/PV scenario. We also modeled the impact of significant increases in customer and demand charges (e.g., recovering 75% of non-fuel costs in customer charge and 50% in residential demand charges) that increased utility achieved ROE by 200 and 69 basis points, respectively. Importantly, these rate design changes are much more profound than what has been currently proposed by utilities. We also found that shareholder incentive mechanisms that seek to mitigate the lost earnings opportunity effect may provide greater or smaller contributions to utility earnings depending on the size and basis (e.g., program costs or resource net benefits) of the incentive (Cappers et al., 2009).

Importantly, these ratemaking and rate design mechanisms may entail substantive tradeoffs. For example, these tradeoffs may exist between ratepayers and shareholders; decoupling and other mitigation measures that involve changes to the way the utility collects revenue may lead to increases in average retail rates. Important tradeoffs may also exist among competing policy and regulatory objectives (e.g., various ratemaking principles or between policy objectives associated with ratepayer equity and environmental goals). Given the complex set of issues involved in implementing many of the possible mitigation measures, regulators may wish to address concerns about the ratepayer and shareholder impacts of EE and distributed PV within the context of broader policy- and rate-making processes.

This analysis also makes important findings about the financial impacts of aggressive EE and PV on participating and non-participating customer bills. Specifically, the timing of when a customer makes an EE or PV investment, as well as the perspective taken on what constitutes a bill impact, matters. Anyone who invests in an EE or PV system that lowers their energy and/or peak demand, either before or during the analysis period, will be financially better off individually for having done so as their reduced consumption level mean their bills are lower than they otherwise would have been absent such investments. However, retail rates go up for all customers in the AEV scenario. Analysis of customer bill impacts should take into account the effects of incremental customer investments on retail rates as it presents a more nuanced perspective to the tradeoff between aggressive savings goals and increased average retail rates.

We found that increases in average retail rates had real financial implications for not just non-participants, who see higher bills over the 10 year analysis period, but also for those whose investments generate more modest savings of energy and demand. Customers who invest in EE measures that produce lower energy savings (e.g., residential product rebate and low income programs) also see higher bills over the 10 year analysis period since their savings are not large enough to offset the rising rates.

As previously discussed, one approach to mitigating the revenue erosion effect is to implement demand charge rate designs that focuses revenue collection more on demand charges than volumetric energy charges. Our results suggest such a ratemaking approach largely does not increase non-participant customer bills and only modestly increases EE customer bills. However, such a change in rate design dramatically reduces the bill savings (i.e., increases customer bills) for PV customers because of the way PV systems produce highly asymmetric reductions in energy and demand.

Areas for future research include:

Examine marginal impacts of EE and PV within a combined portfolio – particularly the ordering effect. Altering our underlying assumptions about the timing of EE and PV hourly savings and whether EE or PV was first applied (i.e., “the ordering effect”) may change the magnitude of financial impacts. Understanding how the impacts may compound and interact will enable more informed judgments about the severity of, and options for holistically addressing possible impacts on utility shareholders and ratepayers.

Benchmark the impacts of EE and customer-sited PV against other factors affecting utility profitability and customer rates. Utility shareholder returns and earnings, as well as retail electricity rates, are impacted by many factors. Various forms of cross-subsidy exist within utility ratemaking. Understanding how the impacts of EE and PV measure up against these other issues may help utilities and policymakers gauge the severity and importance of the impacts and budget their resources accordingly.

Examine a broader range of mitigation options and combinations. The present study considered a subset of possible measures for mitigating the utility and ratepayer impacts from PV. A wide variety of other measures have also been suggested and are worthy of further analysis, including: stand-by rates, time-based pricing, two-way rates such as value-of-solar tariffs or feed-in tariffs, bi-directional distribution rates, non-fuel cost trackers, formula rates, multi-year rate plans, separate customer classes for PV customers, unbundled pricing of utility services, and performance-based ratemaking (e.g., see (Bird et al., 2013; Lowry et al., 2013; Kihm and Kramer, 2014). Analyzing varying combinations of mitigation options may allow for identification of comprehensive utility business and regulatory models that support public policy goals (e.g., all cost-effective efficiency, clean energy goals).

Assess impacts of technologies that increase utility load – including electric vehicles and electric heat pumps. State regulators and legislators are considering policies that encourage adoption of technologies which increase the electrification of the economy (e.g., electric vehicles, electric heat pumps) to meet clean energy public policy goals. Such technologies would increase utility retail sales and possibly peak demand (see Nadel 2016), but may also require new generation, transmission, and distribution assets to accommodate such changes. The net effect of this increased electrification of the economy should be analyzed as it may counter some of the adverse financial impacts of aggressive EE savings and PV penetration on utility shareholders.

Assess rate impacts on customer economics of investment. The financial benefits of investing in DERs, namely customer bill savings, are a critical component of the customer's decision whether or not to do so. Although there has been research into how customer adoption may change as the economic value of investment evolves given changes in costs and value (e.g., Darghouth et al., 2016), the feedback between adoption and utility cost and rate impacts could be improved. Furthermore, customer adoption is often times based on analysis performed by third party service providers who project future retail rate increases based on historical trends (e.g., finding that retail rates will rise by 2%/year over the life of the investment). Using a more realistic model of DER adoption with feedback on how that adoption impacts utility costs, rates and thus future customer investment decisions would provide a more robust understanding of the utility earnings and customer bill impacts over time.

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