The value of solar for PECO and its ratepayers

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Jeremy Keen[1] and Jay Apt[1,2]
[1]Department of Engineering and Public Policy
[2]Tepper School of Business
Carnegie Mellon University

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Acronym List

AEC	Alternative Energy Credit
AEPS	Alternative Energy Portfolio Standard
BAU	Business as Usual
BLS	Bureau of Labor Statistics
D-ELCC	Distribution Effective Load Carrying Capability
DRIPE	Demand Reduction Induced Price Effect
DSIC	Distribution System Improvement Charge
E3	Energy and Environmental Economics
EIA	Energy Information Agency
FPFTY	Fully Projected Future Test Year
kWh	Kilowatt-Hour
G&T	Generation and Transmission
ISO	Independent System Operator
LMP	Locational Marginal Price
LTIIP	Long Term Infrastructure Improvement Plan
MCOS	Marginal Cost of Service
MM	Million
MWH	Megawatt-Hour
NAPEE	National Action Plan for Energy Efficiency
NEM	Net Energy Metering
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PA	Pennsylvania
PCAF	Peak Capacity Allocation Factor
PECO	Philadelphia Electric Company
PJM	Northeast RTO serving 13 states, Originally “Pennsylvania New Jersey Maryland”
PV	Photovoltaic
PUC	Public Utility Commission
ROE	Return on Equity
RPC	Revenue Per Customer
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
T&D	Transmission and Distribution
VOS	Value of Solar
WACC	Weighted Average Cost of Capital
WN	Weather Normalized

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1. Executive Summary

We have developed a utility financial model that describes how the average customer 'all-in-rate' (i.e. the volumetric rate based on the total revenue requirement and kWh sales of all customer classes), will change for different energy penetrations[1] of rooftop solar photovoltaic generation in the PECO (Philadelphia Electric Company) service territory if Pennsylvania continues offering net energy metering (NEM) rates. Under a NEM tariff, if the revenue reduction from solar exceeds avoided costs, customer rates will increase. We define the Value of Solar (VOS) as the avoided energy, generation capacity, transmission capacity, and distribution capacity costs associated with solar in avoided dollars per unit of solar generation ($/kWh).

We estimate the value of solar (VOS) in the PECO service territory to be $0.088±0.006/kWh for a 5% penetration of solar by energy rolled out from 2020-2030 with random placement on distribution feeders. This estimate for the VOS is below our estimate of $0.118/kWh for PECO's all-in-rate; so, if Pennsylvania continues with net energy metering, lost revenue will exceed avoided costs and there will likely be a small, 0.8%, increase in rates at a 5% penetration of solar by energy. The rate increase is relative to the pre-solar expected rates over a time horizon from 2020-2040 and assumes a 5% discount rate. The uncertainty in our estimate arises from weather and load variation in the 10 different historical years (2007-2016) used in the study. Due to the declining value of solar with increasing solar penetration, a solar energy penetration of 10% is likely to increase the all-in-rate by approximately 2%.

We find that solar's effect on PECO's business is small. PECO's return on equity (ROE) is insensitive to revenue erosion from solar because of the recent implementation of a Fully Projected Future Test Year (FPFTY). Revenue per customer (RCP) decoupled rates is pending

[1] We use solar energy penetration to describe how much solar energy is produced in Pennsylvania. It is defined as the total solar energy relative to total energy consumption.

in Pennsylvania and will further protect PECO from volatility in the VOS caused by weather variation. Revenue erosion, however, would still affect PECO through disproportionate changes in the distribution and bulk grid section of customer bills. While the expected increase in the all-in-rate is 0.8%, the distribution portion is expected to increase by 3.3% and the bulk grid portion to decrease by 0.7%.

In this report, we estimate avoided T&D capacity expenses assuming that solar is not targeted at overloaded sections of the T&D network. The combination of solar's slow rollout, the rarity of overloaded networks, and the untargeted placement of solar results in a low T&D VOS, a small effect on rates, and minimal impact on PECO's business model. Solar plus utility owned storage can increase the total deferral value by more than a factor of 4 at 5% penetration, but the impact on rates is small. Keen and Apt (2019) assess the additional value created by targeting solar at overloaded distribution networks. Targeted solar placement can increase the deferral value by up to a factor of 4, but the number of deferral opportunities do not warrant overly complicated market or administrative processes (Keen and Apt 2019).

By displacing fossil fuel generation and reducing criteria pollutant emissions, solar avoids health damages and premature loss of life. These environmental benefits of solar are not included in our model because they do not affect rates but from a societal perspective have a high value in Pennsylvania due to the state's relatively high proportion of coal and natural gas fired power. Perez et al. (2012) estimate the value of solar at $0.05-0.12/kWh in Pennsylvania. This report can be used by decision makers to decide whether these large environmental benefits are worth the small rate impact caused by solar.

2. Model

2.1. Overview

In the year 2021, Pennsylvania will reach the Alternative Energy Portfolio Standard (AEPS) deadline, which includes a 0.5% solar energy penetration requirement. Several other states in the PJM footprint are targeting higher penetrations of solar (Figure 1). Recently, Governor Wolf signed an executive order to reduce greenhouse gas emissions 80% by 2050 in Pennsylvania (Wolf 2019) and the Department of Environmental Protection released a report with strategies to achieve 10% solar energy penetration in the state by 2030 (PA DEP 2019).

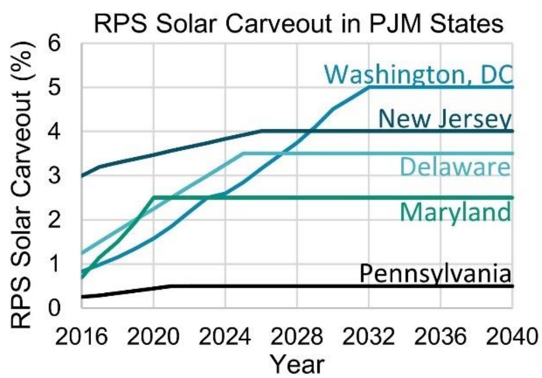

Figure 1: Solar Renewable Portfolio Standards in PJM service territory.

We have developed a utility financial model that describes how the 'all-in-rate' (i.e. the volumetric rate based on the total revenue requirement and kWh sales of all customer classes) changes for different solar energy penetrations in the PECO service territory if Pennsylvania continues offering NEM rates. We define NEM rates as crediting all solar generation at the retail volumetric ($/kWh) rate and crediting reduced peak demand (kW) at the retail demand change ($/kW).

Due to its solar resource, PECO has the largest amount of residential and commercial solar PV installations in Pennsylvania and is a reasonable choice for a Pennsylvania VOS study. In this study, we consider mandated solar energy penetrations in Pennsylvania that range from 1-30%. We assume that the solar is rolled out linearly from 2020-2030 and the solar energy penetration remains constant thereafter. Keen and Apt (2019) assess the targeted placement of solar and allow the penetration to be higher in some locations where reduced loading may defer large capital investments and create value. The benefit of solar plus utility owned storage is considered in both targeted and untargeted capacity deferral modeling.

The utility financial model estimates how the combination of avoided costs associated with solar and lost revenue associated with NEM ultimately affect rates. First, the model forecasts PECO's revenue requirement (i.e. cost of service including debt and equity payments), including pass-through costs and non-pass-through costs. The model begins with PECO's revenue requirement in the year 2016 and forecasts each revenue requirement component based on the relevant escalation factors. Second, a forecast of volumetric sales, customer charges, and demand charges is used with the revenue requirement to baseline customer rates without solar by assuming a rate case every three years. Third, solar is associated with avoided costs (i.e. a lower revenue requirement) and reduced revenue from volumetric sales and demand charges that will affect PECO rates.

2.2. Metrics

Throughout this report, we use three key metrics defined in Equations 1, 2, and 3. The all-in-rate is a volumetric rate based on the revenue requirement and sales for all customer classes. Figure 2, discussed in more detail in the following section, shows the expected all-in-rate by spending category without any solar through 2040. Return on Equity (ROE) is a measure of financial performance showing utility earnings relative to invested equity capital. Solar reduces the revenue requirement by avoiding energy costs, generation capacity costs, transmission costs, distribution costs, and taxes. The VOS is found by estimating the avoided costs and dividing the resulting revenue requirement reduction by all energy generated from solar. Additionally, to evaluate capacity deferral opportunities, we define 'total deferral value' as the numerator of Equation 3 when applied to avoided distribution costs. It is the net present value of all capital expense (capex) deferrals created by solar. The size of the total deferral value is useful for determining which policies are appropriate for managing and encouraging capacity deferral opportunities.

$$All-in-Rate[\frac{\$}{kWh}] = \frac{Utility\ Revenue\ \ [\$]}{Volumetric\ Sales\ [kWh]} \tag{1}$$

$$Return-on-Equity[\%] = \frac{Utility\ Revenue\ [\$]\ \ - Utility\ Costs[\$]}{Ratebase\ Equity[\$]} \tag{2}$$

$$Value\ of\ Solar\ [\frac{\$}{kWh}] = \frac{Change\ in\ Utility\ Costs[\$]}{Solar\ [kWhs]} \tag{3}$$

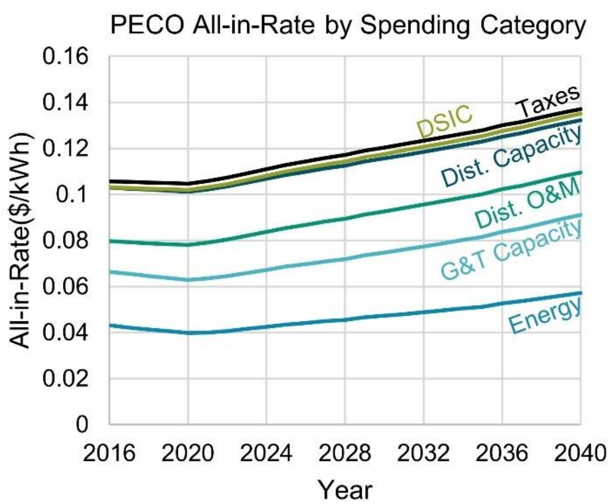

Figure 2: All-in-Rate by spending category (stacked). Spending category components are deescalated equally from 2016-2020 to reflect falling bilateral contract and natural gas prices. Spending category components are escalated separately, resulting in a 1.2% cumulative average growth rate for the all-in-rate from 2020-2040. The all-in-rate is a volumetric rate based on the revenue and sales for all customer classes. Energy is the largest percentage of the all-in-rate and includes the load-weighted locational marginal price (LMP), ancillary services, alternative energy credits (AECs), and the risk premium associated with bilateral contracts. Generation and Transmission (G&T) capacity is the next largest component, followed by distribution O&M and distribution capacity. The distribution system improvement charge (DSIC), a recent Pennsylvania policy aimed at improving resiliency and taxes are a very small percentage of the total rate.

2.3. Utility Financial Model

Figure 2 shows the all-in-rate forecasted by the utility financial model without solar.

Spending category components (energy, generation capacity, O&M etc.) are escalated equally from 2016-2020 to reflect falling bilateral contract and natural gas prices, and separately from 2020-2040 based on Bureau of Labor and Statistics (BLS), PJM Market Data, and EIA Reference Forecasts. Altogether, we forecast a 1.2% cumulative average growth in the all-in-rate from 2020-2040.

Figure 3 and Figure 4 summarize the utility financial model that we use to estimate the metrics defined by equation 1 (all-in-rate), equation 2 (return-on-equity), and equation 3 (value of solar). First, the utility's revenue requirement and actual revenue from customer charges, volumetric rates, and demand charges are forecast. These billing components are allocated in different proportions to pay for each spending category of the revenue requirement. Details of this allocation can be found in the Appendix (Section 6.2). Next, in rate-case years, rates are increased to ensure that the utility earns its full revenue requirement, including a 10% ROE. In non-rate case years, unequal changes in actual revenues and costs lead to changes in the ROE. Typically, if costs increase and decreased sales prevent the utility from achieving the revenue requirement, the actual utility ROE will be less than the target ROE. Pennsylvania utilities may be protected from this effect with a Fully Projected Future Test Year (FPFTY) and revenue per customer decoupling. Modeling details of these policies can be found in the Appendix (Section 6.5).

Rooftop solar customers are sometimes said to create a disproportionate loss in revenue relative to the avoided costs associated with solar (EEI 2016). If the revenue reduction is greater than the avoided costs, the utility ROE will decrease, and customer rates will increase. Stated in another way, if the VOS is greater than the all-in-rate, rates will decrease, and if the VOS is less than the all-in-rate, rates will decrease.

The utility financial model was adapted from a spreadsheet model developed by Energy and Environmental Economics (E3) for the National Action Plan for Energy Efficiency (NAPEE

2007) and later work by Satchwell et al. (2014), which focused on solar's effect on a prototypical deregulated northeast utility and southwest vertically integrated utility. Details of changes that we made can be found in Section 6.4 of the Appendix.

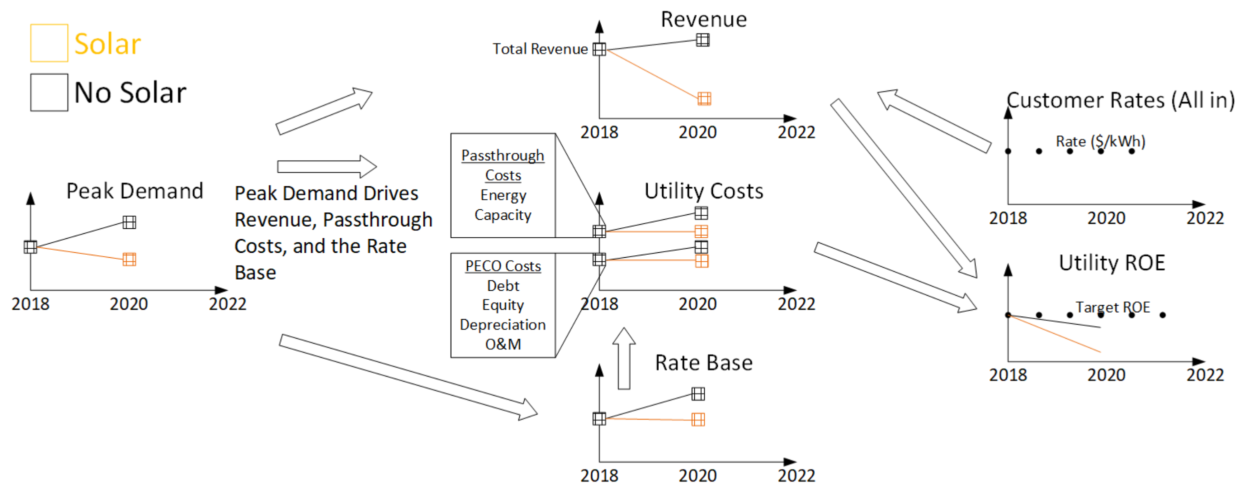

Figure 3: The rate base, utility costs, and revenue change on a yearly basis. In 2020 –an off rate-case year- rates stay the same, but the misalignment between revenue and costs are likely to decrease the ROE.

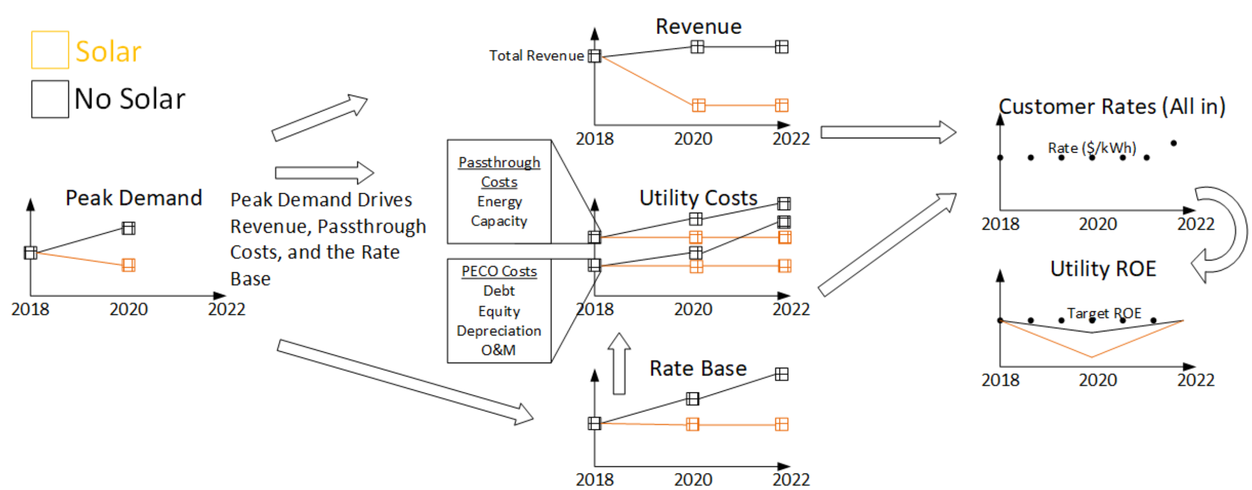

Figure 4: The rate base, utility costs, and revenue change on a yearly basis. In 2022 –a Rate case year- rates are increased to ensure that the utility ROE is 'just and reasonable'.

2.3.1. Avoided Costs

Figure 2 shows each component of PECO's revenue requirement. Solar can avoid costs and therefore reduce the revenue requirements for four of these components: distribution capacity, transmission capacity, generation capacity, and energy costs. These costs are escalated yearly using historical data and forecasts from the Bureau of Labor and Statistics (BLS), PJM Market Data, and EIA Reference Forecasts. We describe each avoided cost component below.

2.3.1.1. Avoided Energy Costs

Avoided energy costs make up the largest component of the value of solar. Most of the avoided energy costs are based on solar's hourly energy output coincidence with PECO's Locational Marginal Prices (LMPs). We add the cost of alternative energy credits, the Demand Reduction Induced Price Effect (DRIPE), ancillary services and the risk premium associated with PECO's bilateral contracts to the avoided energy cost. These avoided costs also include average line losses of 6.4% (PA PUC 2017) and avoided alternative energy credits. The cost of alternative energy credits is small, and details can be found in Section 6.6 of the Appendix.

As solar decreases PJM's net load, LMPs will also decrease and reduce PECO's energy revenue requirement. The reduction in the energy revenue requirement is often treated as a value of solar component and referred to as the market price response or the Demand Reduction Induced Price Effected (DRIPE). We have constructed daily PJM supply curves from public PJM bid data (PJM 2018) to estimate the DRIPE associated with different penetrations of solar. This required several steps. We began with historical hourly LMPs in the PECO Zone (PJM 2018). We next used PJM supply curves (PJM 2018) and PJM hourly loads (PJM 2018) from historical reference years to estimate a PJM wide hourly marginal price. The supply curves were constructed from public bidding data, assuming each generator operates at maximum output. Solar's hourly output for each reference year and energy penetration were calculated using GridLab-D (PNNL 2018) with weather data from the National Renewable Energy Laboratory (NREL)'s Physical Solar Model (NREL 2018). An example of solar's effect on PECO's LMPs are shown in Figure 5 for several weeks in July 2016. Further details of the solar profile that we use and the DRIPE can be found in the avoided energy cost section of the Appendix (Section 6.6).

The combined avoided cost of ancillary services and the risk premium are assumed to be the remainder of PECO's bilateral contracts after subtracting the load-weighted LMP, generation capacity costs, and cost of Alternative Energy Credits (AEC). The average bilateral contract costs were estimated from the "Purchased Power" page in FERC Form 1 (FERC 2016) and PECO's default service supply procurement website (2019). These are "Fixed Price Full Requirement" bilateral contracts that covers all generation aspects (excluding transmission costs) of serving a portion of load during a fixed period of time. Spot market purchases are only about 1% of PECO's energy costs. Figure 6 shows the cost components of the bilateral contract. Ancillary services and the risk premium are estimated to be \$16/MWH in 2016.

Sensitivity Analysis

PECO's average bilateral contract costs have been decreasing in recent years (Figure 7). We assume all components of PECO's bilateral contract are deescalated to match our base case \$55/MWH estimate of PECO's average bilateral contract cost in 2020. \$50/MWH and \$60/MWH are considered in the sensitivity analysis. Beyond 2020, we escalate all cost categories separately. In our base case scenario, LMPs are escalated based on a weighted combination of the EIA reference natural gas and coal forecasts (EIA 2018). The weights for natural gas and coal are 65% and 35%, respectively and are based on the percentage of time that each fuel type is currently on the margin. Marginal fuel usage was taken from Monitoring Analytics Marginal Fuel Posting in PJM's real-time energy market (2018). In our high and low energy escalation scenarios, we use the EIA forecast for high and low oil prices.

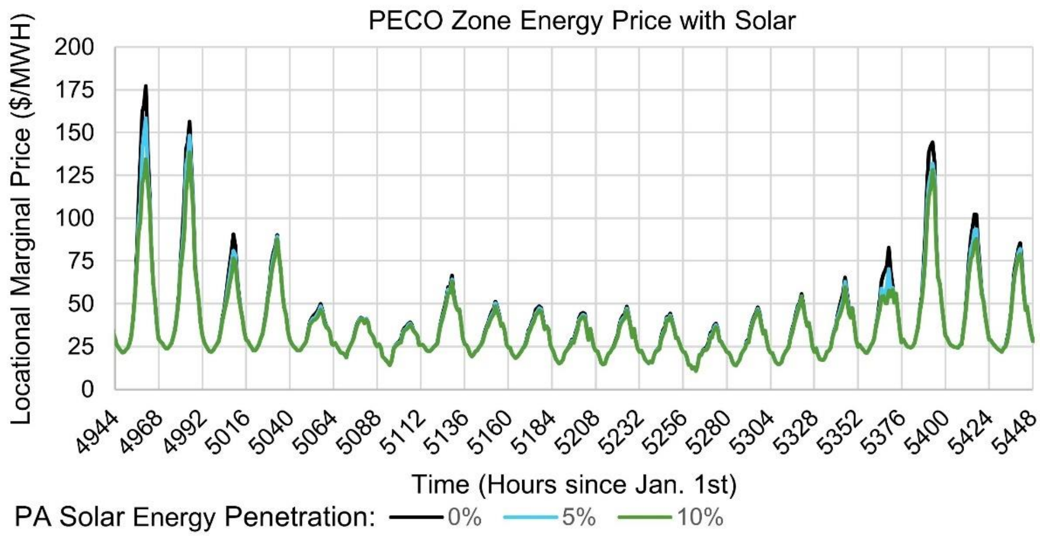

Figure 5: PJM market prices decrease when solar reduces demand during the day. PECO LMPs from 2016 are shown for several weeks in July.

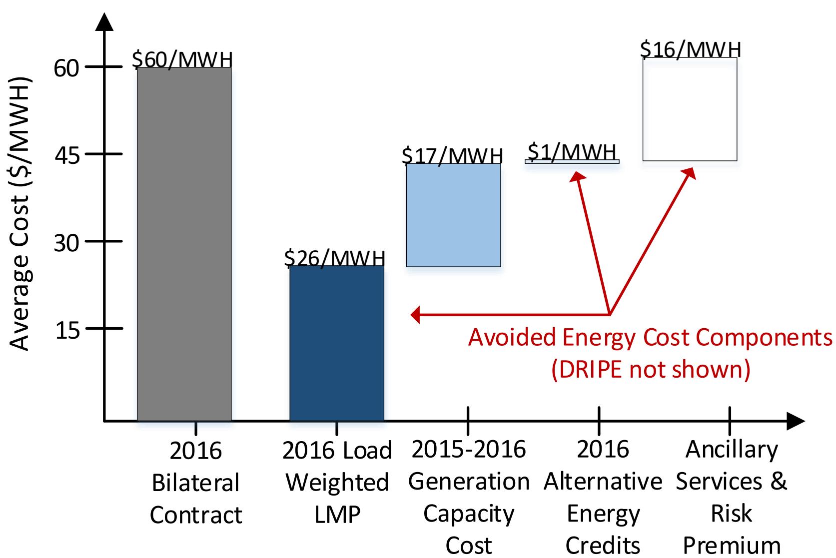

Figure 6: The average bilateral contract cost in 2016 and its components. The load-weighted locational marginal price (LMP), generation capacity and alternative energy credit costs are subtracted from the average bilateral contract cost to estimate the cost of ancillary services and the risk premium. Our energy value of solar estimate includes all components of the bilateral contract except the generation capacity cost. The demand reduction induced price effect (DRIPE) is also included in the energy cost but not included in this figure. The average bilateral contract cost has been declining in recent years and is forecasted to be $55/MWH in 2020. All components are deescalated equally from 2016 to 2020 to match this forecast.

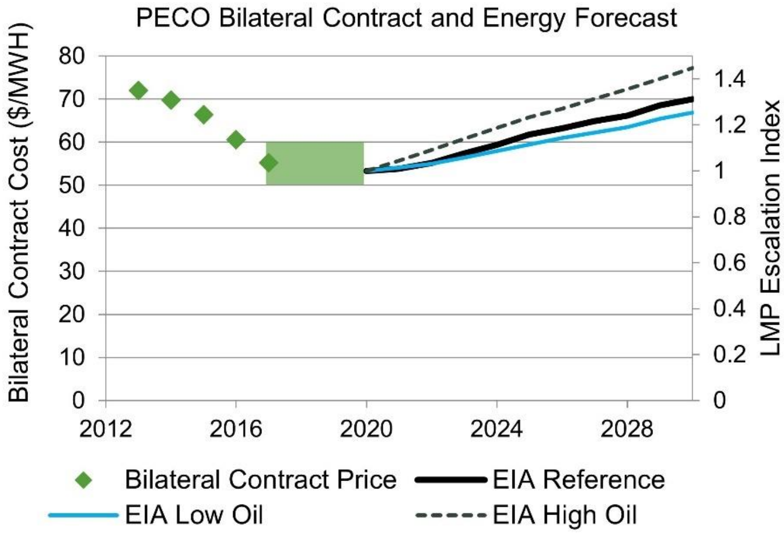

Figure 7: PECO's average bilateral contract has been decreasing in recent years as fuel prices have fallen (FERC 2016) (PECO 2019), and the average bilateral contract price in the year 2020 is uncertain (shaded green region). A bilateral contract of $55/MWH is used in 2020 (the start of the solar rollout). After 2020, the locational marginal price (LMP) component of the bilateral contract is escalated based on the EIA reference forecast for natural gas and coal.

2.3.1.2. Avoided Generation Capacity Costs

When solar reduces PECO's load on peak loading days, PECO's capacity obligation in PJM's capacity market (i.e. the reliability pricing model or RPM) is reduced. The avoided generation capacity cost is the product of the generation capacity credit, the RPM capacity price, and reserve margin. We use $164/MW-day for the capacity price and a reserve margin of 20.5%, both based on PJM's base residual auction (PJM 2018).

The generation capacity credit is based on solar's ability to reduce PJM's weather normalized forecast, which is a key input for calculating PECO's capacity obligation and is described in PJM's Manual 19 (2017). In Figure 8, we show our estimate of the generation capacity credit. The generation capacity credit is defined in Equation 4.

$$Generation\ Capacity\ Credit = \frac{Div.Factor * (Peak\ Load_{WN}(p=0) - Peak\ Load_{WN}(p))}{Nominal\ Solar\ Capacity} \tag{4}$$

The diversity factor is defined by PJM as PECO's coincident peak divided by PECO's noncoincident peak (Reynolds 2017). We use a diversity factor of 0.97, which is an average over all 10 reference years. The weather normalized peak (Peak $Load_{WN}$) is based on a statistical regression using 3 years of weather and demand data (2014-2016). In Figure 9, we show a scatter plot of weather, expressed as Weighted Temperature Humidity Indexes (WTHI's) and demands. The demand values are regressed on the WTHIs and solved at the weather standard (an average of WTHIs on peak load days) to find the weather normalized load. High solar penetrations decrease the demand. Finally, the weather normalized load is scaled by PJM's zonal load forecast and reserve margin, found in PJM's yearly base residual auction.

Sensitivity

The cost of generation capacity has been very volatile and has not shown a clear trend since the beginning of PJM's RPM auction. We use the average capacity market clearing price over the 2015-2016 and 2016-2017 delivery years for the PECO zone for our best estimate ($164/MW-day) in 2016. We reduce the price by one standard deviation for our low estimate ($124/MW-day) and increase it by one standard deviation for our high estimate ($203/MW-day).

For our best estimate of the generation capacity escalation rate, we assume 0% escalation. For our low estimate, we assume -2%, the escalation rate reported by the BLS (2018) for "non-utility" owned generation. For our high estimate, we assume +2%, an escalation rate more typical of escalation rates in the rest of the power sector.

We define the reserve margin as the excess capacity in PECO's 2018 capacity obligation relative to their actual 2018 peak load. Using market data from the base residual auction (PJM 2018), our best estimate of PECO's reserve margin is 20.5%. We use 16% for the low estimate, which is PJM's required reserve margin (PJM 2018). We use 28% for our high estimate, which is the most recent reserve margin for PJM's entire service territory (PJM 2018).

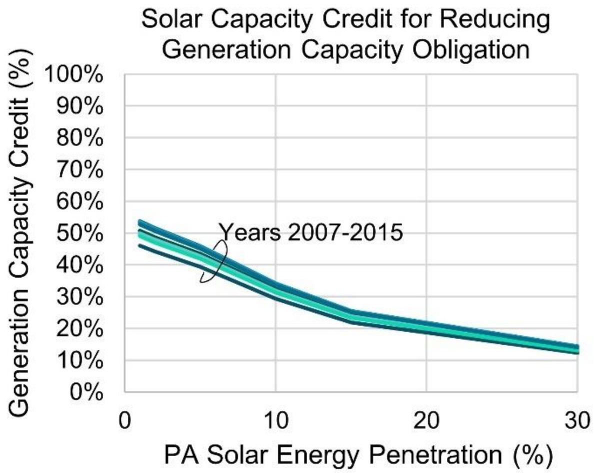

Figure 8: Generation Capacity Credit using 2016 load data. The ability of solar to reduce PECO's coincident weather normalized peak and PJM capacity market obligation diminishes with penetration.

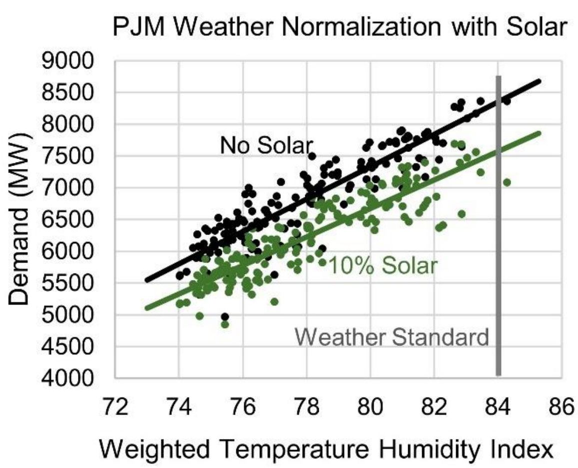

Figure 9: The weather normalized demand is found by regressing PECO's demand on corresponding Weighted Temperature Humidity Indexes and solving at the Weather Standard. The weather normalized demand is lower under the 10% solar penetration scenario.

2.3.1.3. Avoided Distribution Capacity Costs

The distribution capacity deferral value of solar is the value solar creates by reducing overloaded equipment and deferring capital investments to later years. The investment deferral avoids costs in the form of debt and equity payments. We assume that solar is randomly placed throughout PECO's service territory and estimate the deferral value created by the solar that accumulates on overloaded feeders.

We model constant yearly capacity investments caused by overloading, reflecting the relatively constant yearly pipeline of projects planned by most utilities. Solar is rolled out linearly from 2020-2030 and enough solar must accumulate by the year of the planned capacity project for the deferral to take place. If a project is deferred to a later year, solar can accumulate more and defer the project again. Frequently, at low solar energy penetration targets and for projects planned for earlier years, enough solar has not accumulated to defer the project by at least one year. It is possible that these capacity projects could have been deferred if solar was targeted at the capacity project locations. Keen and Apt (2019) assess targeted placement of solar and the additional value it can create.

The distribution capacity deferral value of solar is very sensitive to the cost of replacing or augmenting overloaded capacity, the ability of solar to reduce peak loading, and the growth rate in locations with overloaded capacity. We use the marginal cost of service (MCOS) to estimate the cost of replacing or augmenting overloaded capacity. We estimate PECO's MCOS to be $600/kW, based on 4 growth related projects planned for the next five years (PECO 2018). This estimate is close to distribution capacity cost estimates in California (E3 2018) and New York (NYSERDA 2015).

If the load growth is very low, the deferral will be longer. At typical utility costs of capital, a few additional deferral years can create significant value. We estimate that the average load growth is 1%, based on four PECO growth-related projects planned for the next 5 years.

We call the ability of solar to reduce peak loads the distribution-effective load carrying capability (D-ELCC). This metric is described in detail in Keen (2019), Chapter 3. We use two estimates of the D-ELCC, shown in Figure 10. Both are based on 19 years of solar and loading profiles, and the average of two PECO feeders. D-ELCC_{worst} describes how much solar can reduce the largest net peak load over 19 years for each penetration. It does not allow any overloading.

For capacity deferral projects where transformer overloading is the main constraint, relying on the inherent overloading flexibility of transformers, rather than currently costly energy storage, can also increase the D-ELCC. Our D-ELCC$_{age}$ allows occasional overloading but limits the total transformer aging (i.e. deterioration of insulation) to the aging incurred during typical weather normalization planning processes. D-ELCC$_{worst}$ is low because it is based on evening peaking feeders. As a first order approximation, D-ELCC$_{age}$ can be viewed as the D-ELCC$_{worst}$ on afternoon peaking feeders in regions with a good solar resource (Keen 2019)[2].

In Figure 10, we show the amount of energy storage required at varying penetrations to ensure a D-ELCC of 50%. Below 10% penetration, the energy storage requirements are very low because the energy storage is compensating only for solar variability and does not require peak shifting. Storage creates more deferral value by increasing solar's effective capacity, but it also has a cost. We use installed battery costs reported by the EIA (2018). Storage with durations less than 0.5 hours costs \$2600/kWh, between 0.5-2 hours costs \$1400/kWh, and storage greater than 2 hours costs \$400/kWh. We describe our method for estimating the energy storage duration and size Keen (2019)[2]. Estimates of the energy storage and duration are shown in Keen (2019)[2]. All estimates of the value of solar and total deferral value in this report include these storage costs.

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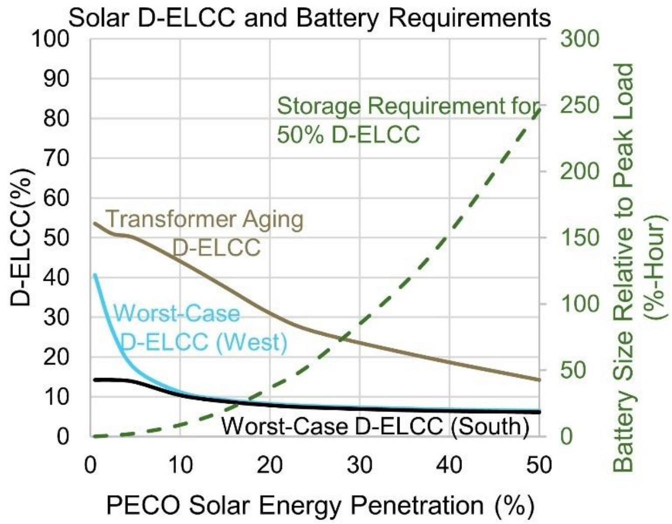

Figure 10: Distribution Effective Load Carrying Capability (D-ELCC). The worst-case D-ELCC does not allow any overloading over the 19 years. The worst-case D-ELCC is shown for South and West facing panels. The energy storage requirement to achieve a 50% worst-case D-ELCC over all penetrations is shown. The transformer aging D-ELCC allows occasional overloading but limits the total transformer aging (i.e. deterioration of insulation) to the aging incurred during typical weather normalization planning processes.

2.3.1.4. Avoided Transmission Capacity Costs

PECO's revenue requirement includes two kinds of transmission costs: non-pass-through PECO owned transmission capacity that is included in PECO's rate base and pass-through regional transmission with costs allocated to multiple load serving entities as dictated by PJM's regional transmission expansion plan (RTEP) and schedule 12 of the Open Access Transmission Tariff (OATT) (PJM 2019). To estimate the avoided transmission costs, we use a method similar to that in the "avoided cost calculator" designed by E3 and used by the California PUC (E3 2018). We first multiply yearly growth-related capex by the reduction in growth caused by solar. While E3 uses the Peak Capacity Allocation Factor (PCAF), we estimate the reduction in growth from the transmission effective load carrying capability. The PCAF and ELCC method are compared in Keen (2019)[3], and the differences should not affect the results in this report. In Figure 11, we show the effective load carrying capability that defines the peak load reduction

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caused by varying penetrations of solar. It is based on the worst-case loading associated with 10 years of historical and solar and loading in the PECO service territory.

We apply a deferral saving factor that accounts for the net present value savings of a deferred capital investment. Based on a 5 year deferral and a 7% discount rate, we use a savings factor of 30%. We estimate PECO and PJM's growth-related capex from project descriptions in PJM's Transmission Cost Information Center (PJM 2019). A description of our criteria for estimating transmission growth-related capex is in the Avoided Transmission Costs Section 6.6 of the Appendix.

Sensitivity

Transmission costs have been increasing rapidly. Our best estimate of the transmission escalation rate is 4.3% based on the average Bureau of Labor and Statistics (BLS) Power Purchasing Index (PPI) growth over the last 10 years (Bureau of Labor Statistics 2018). Our low estimate is 2% which is approximately one standard deviation below the BLS average and more typical of escalation rates for distribution. Our high estimate is 6.6%, which is one standard deviation above the BLS average.

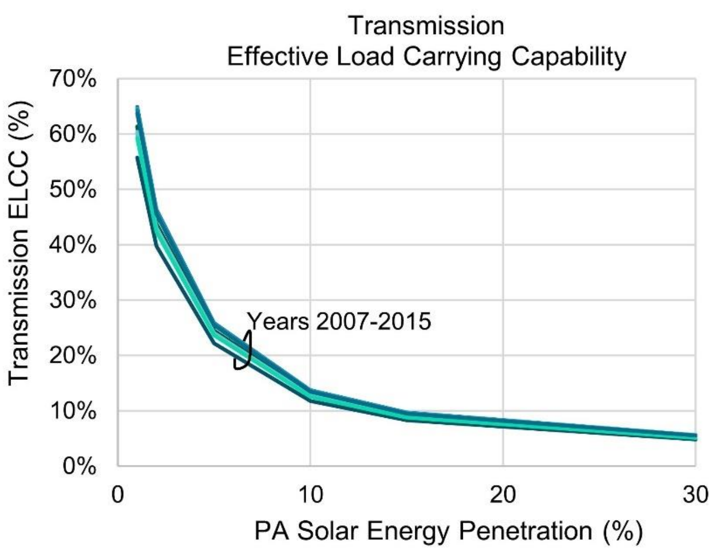


Figure 11: Transmission capacity credit for PECO using 2016 load data. The ability of solar to reduce PECO's coincident peak (with PJM) and transmission demand charge diminishes with penetration.

2.3.1.5. Solar Integration Costs

PECO charges application and interconnection fees to solar owners to cover administrative and integrations costs. Because costs associated with these fees are paid for by solar owners, they will not affect the rates for other customers and are omitted from this study. We assessed when high penetrations may cause additional distribution interconnection costs that could be passed to other customers.

In 2012, Southern California Edison studied integration costs on four feeders in response to a state policy to install 4,800 MW of renewable DER in the service territory by 2020 (Southern California Edison 2012). The study found that the cost of integrating renewable DER would be approximately $4.5 Billion but could be reduced to $2.1 Billion if the DER were "guided" towards stronger grid locations that are less affected by DER. Specifically, the study cites long rural feeders and low voltage feeders (e.g. 4 kV) that are particularly prone to high integration costs. Assuming an 18% AC solar capacity factor, these costs equate to approximately $0.007-0.04/kWh-solar depending on whether solar was placed predominantly in urban or rural feeders. Notably, the study focused on large solar installations in the 1 to 3 MW range, which are common in rural California where land is cheaper, and the solar resource is stronger. The integration costs include distribution upgrades, transmission upgrades and interconnection facility costs.

We examined four PECO feeders and found that the number of voltage violations on these feeders are low at low solar energy penetrations. Depending on the feeder, the number of voltage violations begins to increase rapidly when energy penetrations reach 5-10%. We did not find distribution system reconductoring to be very effective at reducing voltage violations. Installing Volt/Var smart inverters with reactive power priority was the most effective, and we found the costs of real power curtailment associated with this type of inverter to be negligible (less than a 0.01 ₵/kWh). Beyond solar energy penetrations of 5-10%, more expensive interconnection costs, such as those described by Southern California Edison, may be incurred. Modeling details of this study are described in the Section 6.7 of the Appendix.

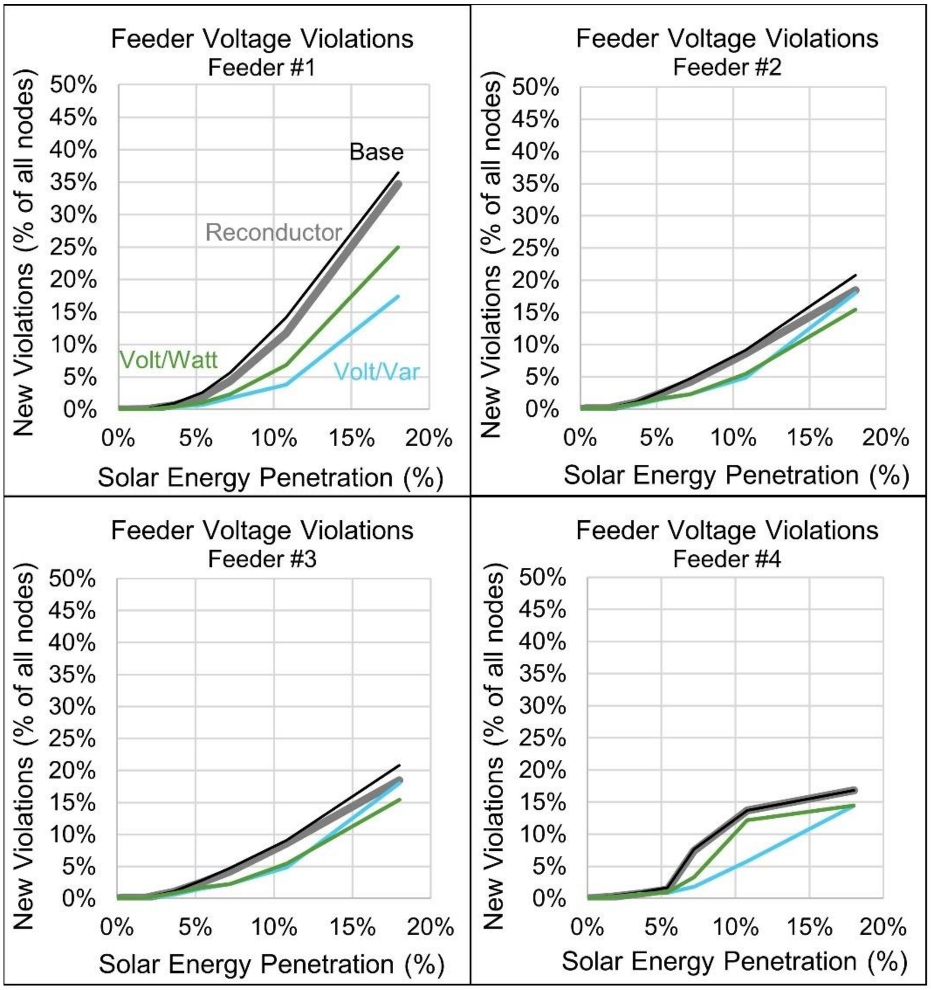


Figure 12: The number of voltage violations are small below 5% energy penetration but begin to increase quickly for penetrations ranging from 5-10%. Volt/Var is a smart inverter with reactive power priority. We found Volt/Var smart inverters to be most effective and the least-cost method for mitigating voltage violations.

2.4. Base-Case Input Assumptions

Table 1 summarizes our base-case assumptions. The data come primarily from PJM market data, PECO's 2015 rate case, Pennsylvania's Alternative Energy Portfolio reports, FERC Form 1, Pennsylvania Electric Power Outlook Reports, and internal PECO data. The utility financial model uses hourly historical PJM loads, PECO loads, solar insolation, and PECO zone LMPs.

To account for yearly variability in the VOS caused by these hourly values, we do sensitivity analysis on the years 2007-2016. Further details on these historical reference years can be found in Section 6.1 of the Appendix.

Table 1: Parameters for the utility financial model. Solar is installed randomly throughout the service territory and solar owners are compensated at the retail rate (i.e. with Net Energy Metering).

Parameter	Value	Source
Study Period	2016-2040. Solar deployed 2020-2030	-
Solar PV Compensation	Net Energy Metering (NEM)	-
Peak Load, Growth	8,364 MW, 0.7%	(PJM, 2016)
Load Factor	48.6%	(PA PUC, 2017)
Forecast Sales Growth	0.6%	(PJM, 2016)
Customer Count, Growth	1.6 Million, 0.52%	(PA PUC, 2017)
Average, Peak Losses	6.4%, 8%	(PA PUC, 2017)
Rate Base Assets	$4,100 Million	(PA PUC, 2015)
Avg. Asset Book Depreciation	30 years	(FERC, 2016)
Capex, Escalation	$398 Million at 2% escalation	(FERC, 2016) (Bureau of Labor Statistics, 2018)
LTIIP Capex	$55 Million	(FERC, 2016)
O&M, Escalation	$829MM at estimated 0.5% escalation	(FERC, 2016)
Rate Case Trigger	Every three years	(PA PUC, 2018)
Test year	“Fully Projected Future Test Year” (2 years)	(PA PUC, 2012)
Regulatory Lag	1 year	(PA PUC, 2018)
Target Return on Equity	10%	(PA PUC, 2015)
Debt Cost, percentage	5.04%, 46.64%	(PA PUC, 2015)
Federal Tax Rate	20%	(IRS, 2018)
State Tax Rate	9.99%	(PA Dept. of Revenue, 2019)
Average Bilateral Contract	$55/MWh in 2020 (includes load-weighted LMP, capacity market, ancillary services, AEPS costs, and the risk premium)	(PECO, 2019)
Energy Escalation Rate	Indexed to EIA reference forecasts for coal and natural gas	(EIA, 2018)
Generation Capacity, Escalation	Average 164/MW-day and estimated 0% escalation based on recent years	(PJM, 2018)
Reserve Margin	Estimated 20.5% planning margin.	(PJM, 2018)
PJM Transmission Escalation	4.3%	(Bureau of Labor Statistics, 2018)
PJM Transmission Growth Capex	Estimated from PJM Transmission Cost Information Center. $46MM/year	(PJM, 2019)
PECO Transmission Growth Capex	Estimated from PJM Transmission Cost Information Center. $6MM/year	(PJM, 2019)
REC Price	Estimated from PA AEPS Reporting. $8/MWH	(PA PUC, 2016)
Growth Related Capex	1% of distribution capex or $3MM per year	(PECO, 2018)
Distribution Marginal Cost of Service	Estimated $600/kW from four recent projects	(PECO, 2018)
D-ELCC	Based on worst case loading over 19 years and two PECO feeders.	(Keen, 2019)

3. Results

3.1. Ratepayer Impact

Figure 13 shows the revenue requirement by spending category without solar and with 5% solar energy. Reductions in the revenue requirement are concentrated among the generation capacity, PJM transmission capacity, and energy pass-through costs. Changes in PECO's T&D capacity revenue requirements are small because few capacity deferral opportunities exist.

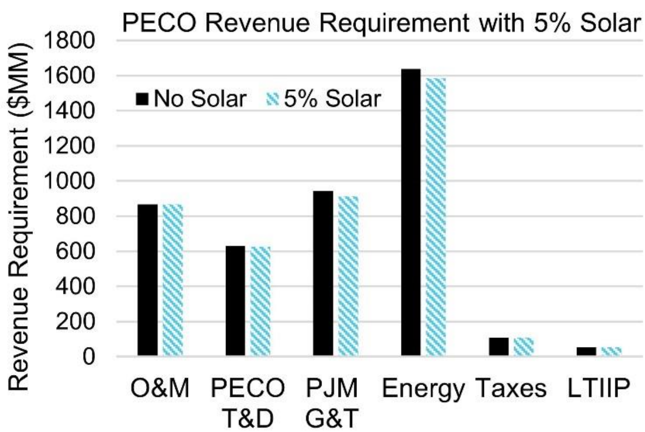


Figure 13: PECO Revenue Requirement with 5% Solar energy in the base case scenario. Generation and Transmission (G&T) and energy are pass through costs. O&M and Distribution Capacity are non-pass through costs. The Long-Term Infrastructure Improvement Plan (LTIIP) refers to capex allowed in Pennsylvania to improve resiliency.

In Figure 14, we show the combined VOS for the energy component, generation capacity, transmission and distribution capacity component. Altogether, the VOS averages $0.088±0.006/kWh at 5% penetration. The range is caused by variations in the actual weather and load profiles during the 2007-2016 reference years. Because our best estimate of the energy, generation, and transmission VOS is below the all-in-rate, we expect that NEM will very slightly increase customer rates.

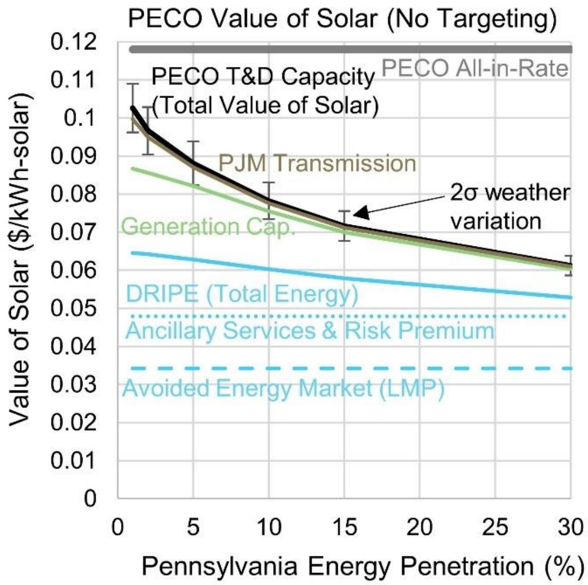


Figure 14: Energy, generation capacity, and transmission value of solar. The untargeted distribution capacity value of solar is very small. The total value of solar falls below PECO's all-in-rate, so rates are likely to increase.

Figure 15 compares the all-in-rate (without solar) to the value of a 5% solar energy target over time and shows the resulting increase in the all-in-rate (with solar). In 2020, the VOS is high because the penetration is very low resulting in a relatively high effective capacity of solar for generation and transmission capacity. As the penetration increases over time to meet the 5% solar energy target, the VOS decreases. After 2030, the solar energy penetration remains constant and the VOS increases as generation, transmission, and distribution costs increase.

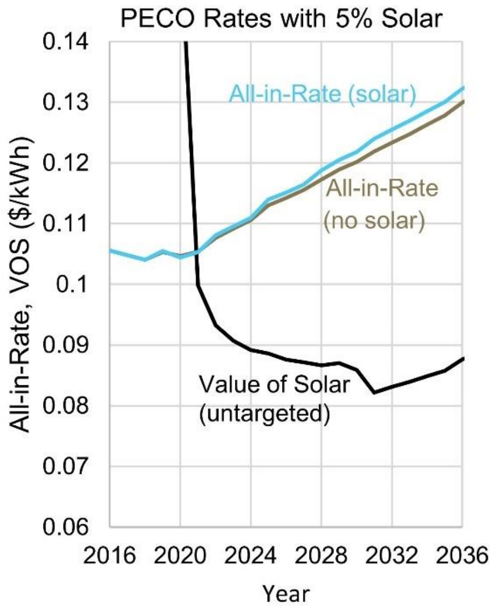
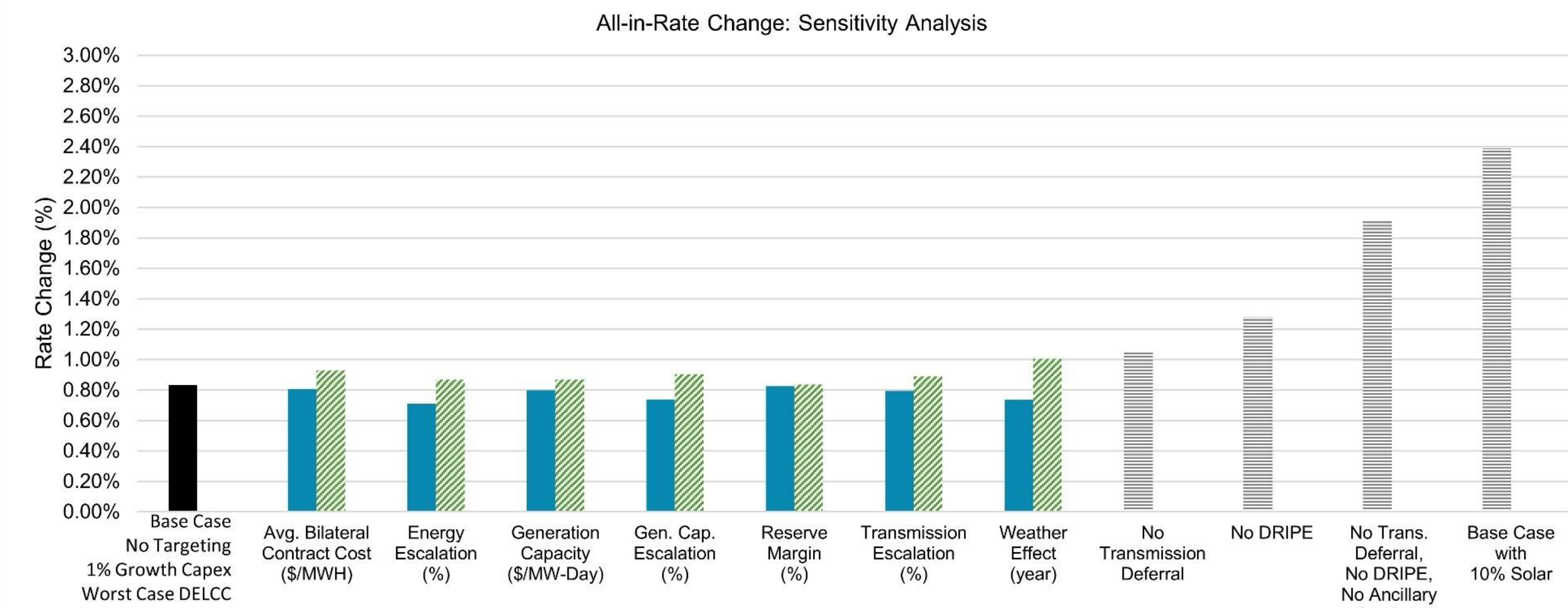


Figure 15: Value of 5% solar energy over the study period and its effect on rates. There is a 0.8% average increase in the all-in-rate with solar relative to the all-in-rate without solar. In 2020, the VOS is high because the penetration is very low resulting in a relatively high effective capacity of solar for generation and transmission capacity. As the penetration increases over time, the VOS drops rapidly.

In Figure 16, we perform sensitivity analysis on several key assumptions. In the "Base Case" scenario, we assume NEM rates for solar owners, a 5% solar energy penetration target by 2030, no solar targeting at overloaded feeders and the worst-case D-ELCC. Detailed base case assumptions are shown in Table 1 and sensitivity assumptions are shown in the table below the bar chart of Figure 16. We find that a 5% solar energy penetration is most likely to cause a 0.8% increase in the all-in-rate (or a 0.2₵/kWh increase by the year 2040). The all-in-rate is very sensitive to the inclusion of the DRIPE, ancillary services, and the solar penetration. Overall, most of the sensitivity scenarios are consistent with 5% solar leading to a very small increase in rates.



High	40	Low Oil	124	-2	16	6.6	2014
Base	45	EIA Ref.	164	0	20.5	4.3	avg
Low	50	High Oil	203	2	28	2	2008

Figure 16: Estimated change in the all-in-rate from solar and sensitivity analysis. In our base case, we estimate that a 5% solar penetration will increase the all-in-rate by 0.8%. While the rate impact is sensitive to which components are included in the value of solar, the largest rate impact would be caused if Pennsylvania had a 10% solar energy penetration rather than a 5% solar energy penetration.

3.2. Utility Impact

Although solar is likely to very slightly increase customer rates, current Pennsylvania regulations make PECO mostly financially indifferent to solar. In Figure 17, we show PECO's ROE with and without solar, and under different test-year and decoupling scenarios. As before, we assume the base case described in Table 1. Without decoupling or the FPFTY, solar causes a consistent reduction in PECO's ROE. Assuming a historical test year, PECO's average ROE from 2020-2040 would be 9.5% without solar but would drop to 9.3% with 5% solar. With the FPFTY, PECO's ROE remains at 10% with or without solar. Revenue decoupling further improves PECO's ROE beyond the allowed 10%. These overearnings may be limited by the PA PUC.

Revenue erosion may indirectly affect PECO through disproportionate changes in the distribution and bulk grid section of customer bills. Table 2 shows the 20 year average rate impact for distribution (non-pass-through) and bulk grid (pass-through) portions of customer bills by billing determinant and the all-in-rate for a 5% solar energy penetration and no solar. While the increase in the all-in-rate is just 0.8%, the distribution portion increases by 3.3% and the bulk grid portion decreases by 0.7%.

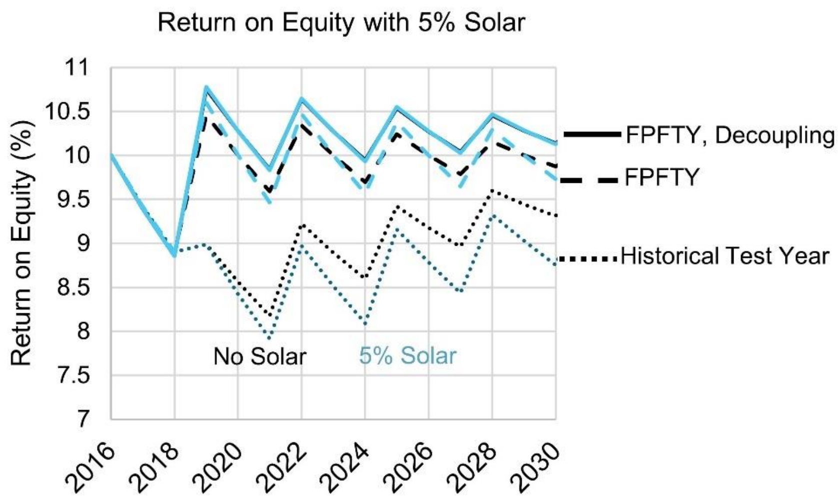


Figure 17: PECO Return on Equity (ROE). With the Fully Projected Future Test Year (FPFTY), PECO's ROE average 10% regardless of the solar penetration.

Table 2: 20 year average rate impact for distribution (non-pass-through) and bulk grid (pass-through) portions of customer bills by billing determinant and the all-in-rate for a 5% solar penetration and no solar targeting. Solar avoids more costs on the bulk grid than on distribution networks and would cause a disproportionate increase in distribution network rates.

	All-In-Rate (%)	Volumetric (%)	Customer (%)	Demand (%)
non-pass through	3.30%	3.30%	-0.19%	2.74%
pass through	-0.67%	-0.67%	n/a	-0.20%
combined	0.83%	0.51%	-0.19%	1.47%

3.3. Distribution Capacity Deferral

Figure 18 shows the value of solar for distribution capex deferrals and the total deferral value for both transmission and distribution. The value of solar is not high enough to significantly affect rates. Furthermore, the combined T&D deferral value at 5% solar energy penetration is \$10-15MM from 10 years of solar deployment, and it probably does not justify large administrative efforts to capture that value. The effective capacity of solar, MCOS, and growth rate all affect the value created by solar. These results are also very sensitive to the total amount of deferrable capex, which is not well documented and may vary considerably between utilities. Figure 19 show the rate impact, total deferrable value, and earnings reduction if 10% of PECO's capex were deferrable each year. Under this higher deferrable capex scenario, more deferrable value is created. Keen and Apt (2019) revisit these estimates assuming that solar can be targeted at overloaded locations. Compared to untargeted placement, targeted placement can increase the total deferral value fourfold, but the effect on rates remains small because few capacity deferral opportunities exist. Further research is recommended to better understand how reduced loading from solar may reduce capital investments, particularly in ways that do not fit into the capacity deferral paradigm.

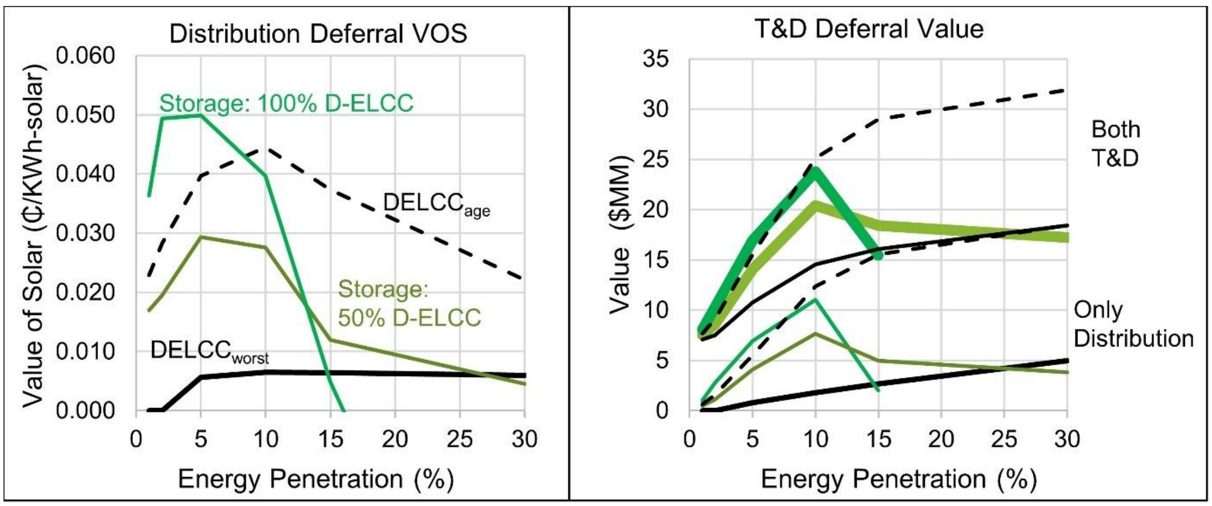


Figure 18: Distribution VOS, and the T&D total deferral value. Under the assumption of 1% growth related capex deferral opportunities, $3MM in distribution capex can be deferred each year. The T&D deferral value and T&D VOS are low.

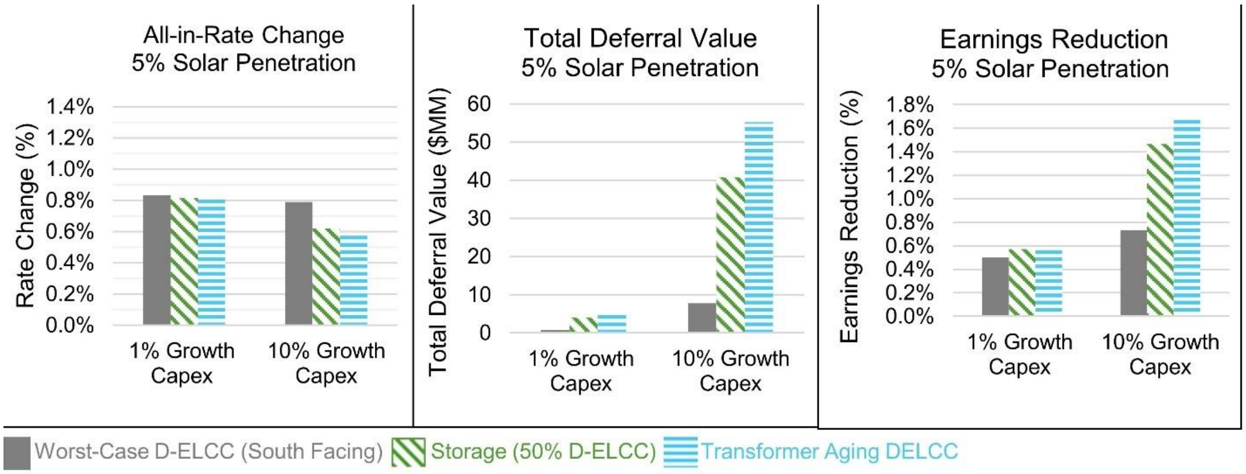


Figure 19: The all-in-rate change, total deferral value and earnings reduction assuming that 1% and 10% of PECO's distribution capex is deferrable. PECO's best estimate is that 1% of distribution capex is deferrable ($3MM per year). The 1% deferrable capex scenario probably does not justify large administrative efforts to capture the deferral value.

3.4. Comparison with Previous Value of Solar Research

Our findings are consistent with other value of solar studies and rate impact tests. A study by Perez et al. (2012) prepared for the Mid-Atlantic Solar Energy Industries Association (MSEIA) estimated a $0.33/kWh value of solar for Philadelphia at a 7% energy penetration of solar. The MSEIA reported estimated the VOS from energy, generation capacity, and T&D at $.081/kWh. The MSEIA estimate for DRIPE added another $0.051/kWh, which is higher than our estimate and other estimates for the DRIPE that we have reviewed. The remainder of the avoided costs is from environmental, security enhancement, long term societal, fuel price hedging, and economic development value. A thorough review of the value of solar findings in other states is provided by E3 in their report for the New York State Energy Research & Development Authority (2015), and by the Rocky Mountain Institute (2013). A challenge in interpreting these studies is that VOS estimates cover more than an order of magnitude, from $0.03/kWh to $0.35/kWh.

Unique features of our study include a rate impact assessment and detailed modeling of the distribution capacity deferral value of solar. Using an earlier version of the utility financial model applied to a typical Northeastern utility, Satchwell et al. (2014) of Lawrence Berkeley

National Lab (LBNL) estimate that a 5% penetration of solar will increase rates by 0.7%. This estimate is very close to our own estimate of a 0.8% increase in rates. Our estimate for the value of solar is lower than the LBNL report because energy costs have declined and because we estimate a lower distribution deferral value of solar.

Our estimate of the T&D capacity deferral value of solar is most like Cohen et al. (2016). They estimate a distribution deferral value of solar in California ranging from 0.05-0.20 ₵/kWh without targeting, which is similar to the estimates we provide in Figure 18. Cohen et al. (2016) also estimate a targeted VOS at 0.25-1 ₵/kWh, but their targeting definition does not place more solar in overloaded networks. Solar is placed randomly on all networks and the deferral value is distributed only among solar owners in overloaded networks. Keen and Apt (2019) assess the targeted placement of solar in the PECO service territory.

4. Conclusion

We find that Pennsylvania can offer Net Energy Metering (NEM) rates up to 5% solar energy penetration with only a small (0.8%) increase in rates. Our result is similar to a Lawrence Berkeley National Lab (LBNL) report estimating a 0.7% increase in rates for a 5% penetration on a “typical Northeastern” utility (Satchwell, et al. 2014). Because of the recent implementation of the Fully Projected Future Test Year and pending implementation of revenue per customer decoupling, a 5% energy penetration of solar is unlikely to negatively affect Pennsylvania utilities. Additionally, solar has benefits that are not included in this rate impact test. By displacing fossil fuel generation and reducing criteria pollutant emissions, solar avoids health damages and premature loss of life. A study by Perez et al. (2012) estimates this value of solar at $0.05-0.12/kWh. This report can be used by decision makers to decide whether these large environmental benefits are worth the small rate impact caused by solar.

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6. Appendix

6.1. Historical Reference Years

The utility financial model uses hourly historical PJM loads, PECO loads, solar insolation, and the PECO zone LMPs. The years 2007-2016 are used for these inputs, and we refer to them as historical "reference years". The model is run for each reference year for the full duration of the model time span (2016-2040) and the results are averaged over all reference year results. When there are discrepancies between reference year attributes and inputs from the year 2016, we multiplicatively scale the reference year. For example, the 2008 load weighted LMP is $81/MWH while the entire 2016 bilateral contract cost is just $60/MWH, so we scale the 2008 hourly LMP downwards. Similarly, PECO's yearly loads do not perfectly match our input load factor for PECO and are scaled accordingly. Our motivation for this treatment is to remove the effect of trends (e.g. load growth) over the reference years while still capturing the variation in load, solar, and LMP profiles that cause variation in the value of solar.

6.2. Billing Determinants

The utility earns revenue from three billing determinants: fixed charges ($/customer), demand charges ($/kW), and volumetric charges ($/kWh). The revenue earned from the billing determinants is allocated to several different spending categories, shown in Table 3 and based on PECO's accounts (PECO 2016). We assume this allocation stays constant for varying energy penetrations of solar. If solar, for example, reduces the volume of sales without reducing peak demand and distribution capacity revenue requirements, there will be an increase only in customer volumetric rates. A newer source of revenue in Pennsylvania comes from the LTIIP (Long Term Infrastructure Improvement Plan). The LTIIP allows utilities to recover investments in aging infrastructure through a Distribution System Improvement Charge (DSIC)-a volumetric rate that can change quarterly. The LTIIP is unaffected by solar.

Table 3: Revenue from the billing determinants are allocated to the major utility spending categories based on PECO's accounts.

	Billing Determinant		
Spending Category	**Fixed Charge (%)**	**Demand Charge (%)**	**Volumetric Charge (%)**
O&M	16	21	63
Distribution	16	21	63
Generation	0	50	50
Transmission	0	50	50
Energy	0	0	100
Taxes	16	21	63
LTIIP	0	0	100

6.3. Customer Class and Net Energy Metering Model

Net Energy Metering (NEM) compensates solar owners at the retail rate. In our model we aggregate all customer classes and expand the NEM definition to include both volumetric and demand charges. This was a necessary simplification to limit data requirements but does prevent us from estimating cross-subsidies between classes. We do not think it will significantly change the metrics used in this report because solar capacity is distributed among the commercial and residential classes in PECO's service territory similarly to PECO's revenue from those same classes. This assumption would be less tenable if solar was installed in one customer class. For example, if PECO only had solar customers in the commercial class, the model would overpredict a loss in volumetric sales that may differ from revenue associated with a loss in demand charge revenue.

6.4. Utility Financial Model: Version History

The utility financial model was adapted from a NAPEE spreadsheet model (2007) and later work by Satchwell et al. (2014), which explored a variety of policy options to mitigate the negative effects of rooftop solar for a typical Northeast utility. We replicated key results of this work in Analytica™ and have made several changes to better represent Pennsylvania and PECO. Major changes include:

- Adapting the model to PJM rules and rates.
- Adapting the model to Pennsylvania regulatory and ratemaking processes, such as the FPFTY and Revenue Per Customer (RPC) decoupling.
- Hourly modeling of Locational Marginal Prices (LMPs), solar insolation, and loads to estimate avoided costs and the declining value of solar with increasing penetration.
- 10 historical reference years to capture the changing value of solar with different weather, load, and market prices.
- Explicit modeling of transmission and generation capacity credits, especially as a function of increasing solar and historical reference years.
- Explicit modeling of the Demand Reduction Induced Price Effect (DRIPE), especially as a function of increasing solar and historical reference years.
- Forecasts of solar in other PJM states based on RPS standards.
- Detailed modeling of the distribution capacity deferral process.

Figure 20 through Figure 23 show several key modules from our adaptation of the utility financial model in Analytica®.

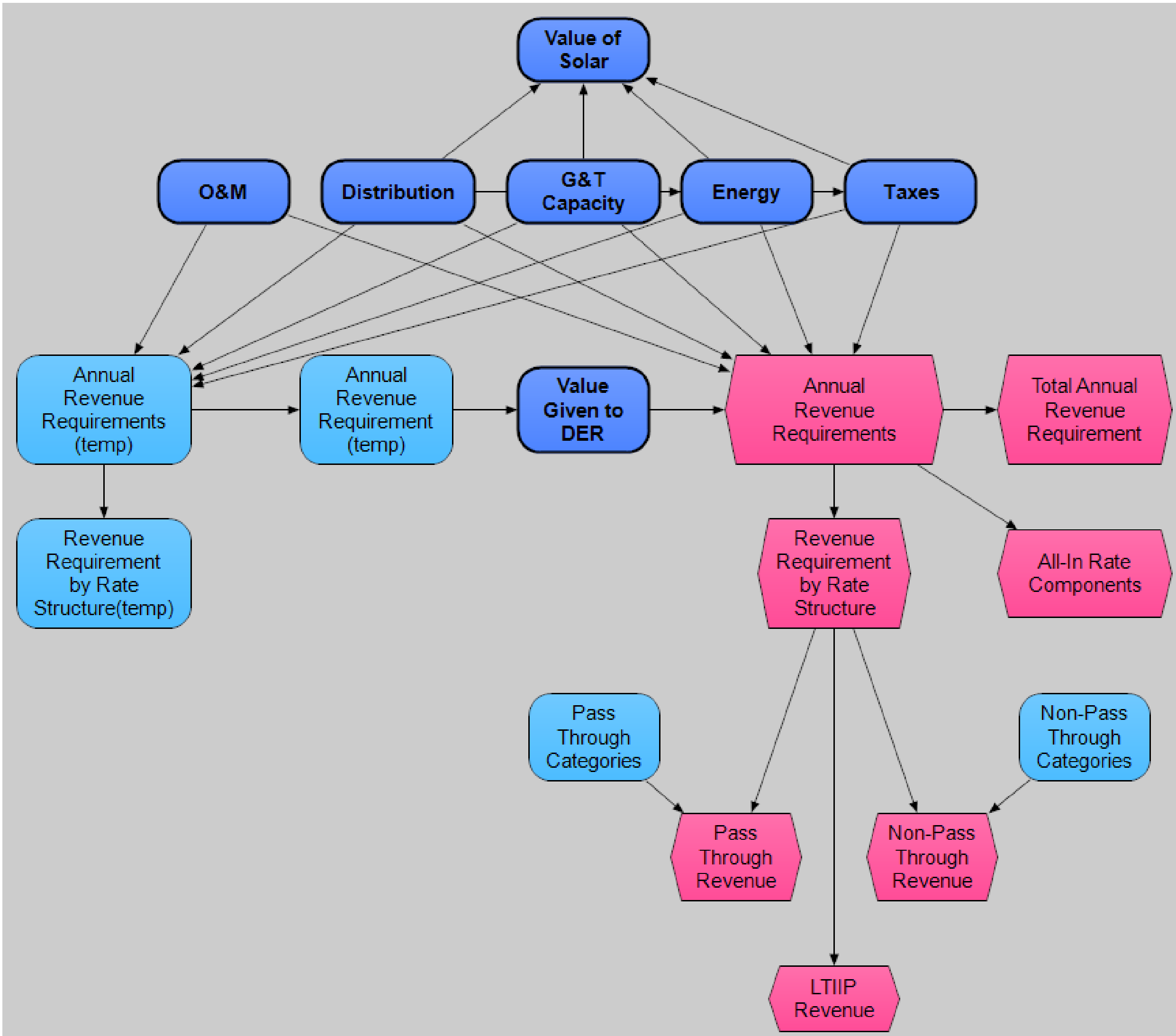

Figure 20: Utility Financial Model: revenue requirement and value of solar module

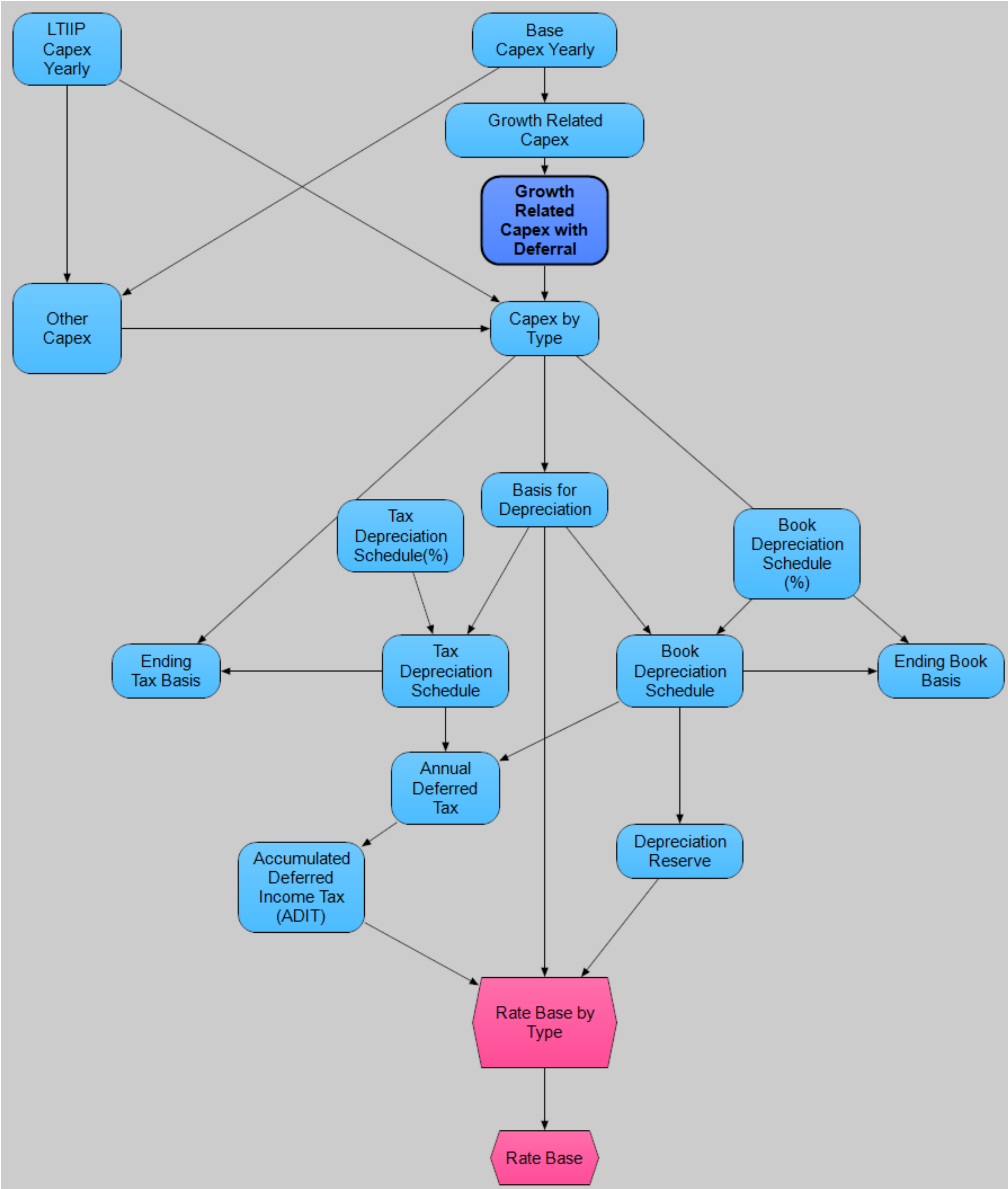

Figure 21: Utility Financial Model: rate base module

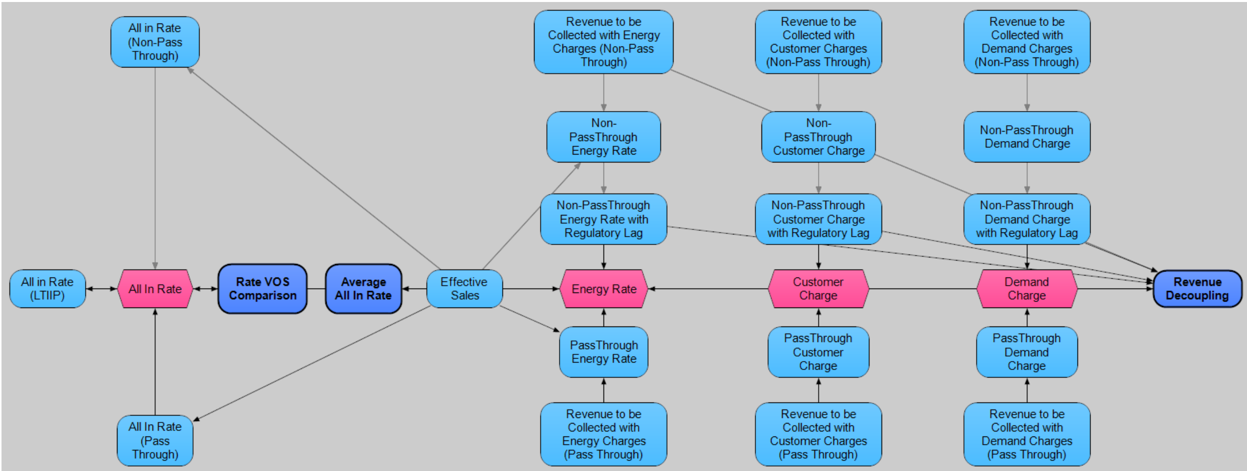

Figure 22: Utility Financial Model: Billing determinants module

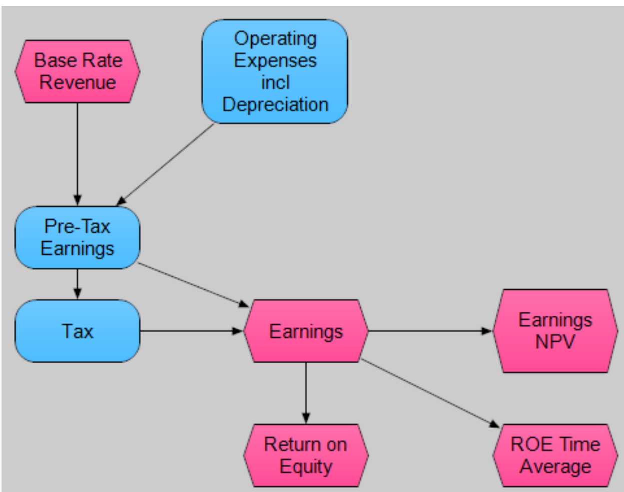

Figure 23: Utility Financial Model: Return on equity module

6.5. Rate Case Modeling

Utilities are permitted to charge high enough rates to earn a reasonable return on equity (ROE), typically around 10%. In practice, changing costs and revenue between rate cases cause fluctuations in the ROE. Several factors complicate utility revenue collection and thus, their achieved return-on-equity. There is typically a delay between when rates are set and the year they take effect. This is known as “regulatory lag”. We use a regulatory lag of 1 year, which is typical for Pennsylvania and most utilities. Furthermore, Public Utility Commissions, like the PA PUC, typically, do not set rates based on data in the rate case year. Instead, they use data from a “historical test year”, usually one year before the rate case. Together, regulatory lag and the use of a historical test year can significantly reduce a utility’s achieved ROE relative to the target ROE. This difference occurs when costs increase at a faster rate than revenue. Assuming a 1 year historical test year and a 1 year regulatory lag, there is an effective 2 year delay between the data used to set rates and the year rates go into effect. During this time, increasing costs decrease the utility’s profit and therefore, decrease the return on equity. Solar and Net Energy Metering is often associated with a further reduction in utility revenue that is not fully counteracted by equivalent reductions in costs. Consequently, with increasing solar penetrations, under Net Energy Metering, historical test years, and regulatory lag, many utilities are concerned with large reductions in their return-on-equity.

In recent years, Pennsylvania has implemented several policies effectively eliminating regulatory lag. These policies are the fully projected future test year (FPFTY), Distribution System Infrastructure Charge (DSIC) (PA PUC 2012) under docket number M-2012-2293611, and the pending implementation of revenue per customer decoupled rates (PA PUC 2018).

The FPFTY sets rates on projected revenue requirements, costs, and sales two years into the future. There is still one year of regulatory lag following the rate case, so one year after the rate case, the utility over collects. Assuming costs are increasing, rates are set to allow more revenue in the first year than the expected revenue requirement. In the second year after the rate case, assuming cost projections were accurate, the utility earns the target return-on-equity. In the third year after the rate case, increasing costs result in under-collection and a return-on-equity below the target. It is typical for the Pennsylvania PUC to allow rate cases every three years, so the utility can expect the cycle to repeat in the following year with over-collection. Figure 24 illustrates how the utility ROE changes with a historical test year and with the FPFTY.

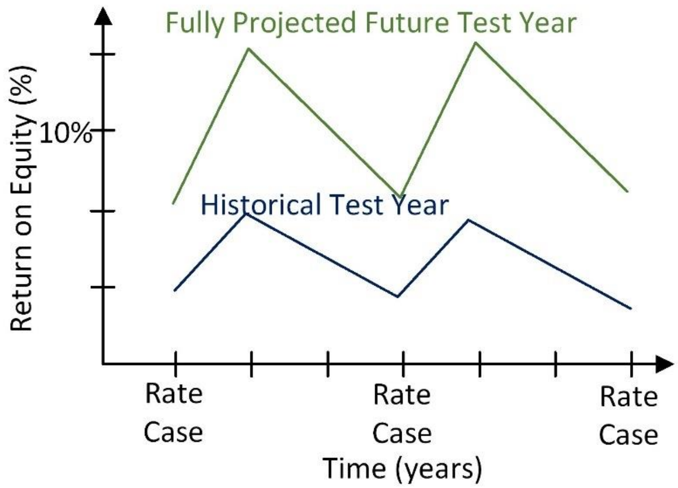

Figure 24: Comparison of utility ROE with Fully Projected Future Test Year (FPFTY) and a historical test year. Regulator lag prevents utilities from earning the target return on equity (10%). The FPFTY sets rates based on forecasted costs two years in advance, resulting in overcollection in the first year after the rate case.

The purpose of the DSIC is to encourage utilities to invest in aging infrastructure and to improve resiliency, but it also decreases regulatory lag. Utilities are permitted to submit Long Term Infrastructure Investment Plans (LTIIP) for replacing aging infrastructure. If approved, utilities pass costs related to these investments through to customers on quarterly basis, effectively bypassing the rate case process and eliminating any regulatory lag. One exception to this rule is that Pennsylvania utilities cannot collect the DSIC if they have already collected more than the revenue requirement allowed under the FPFTY.

Revenue decoupling takes a more direct approach to eliminating over and under collection. After estimating the revenue requirement in the rate case year, a projected revenue requirement is found for future years. Different mechanisms exist to project the revenue requirement (RAP 2011). Based on discussions with the Pennsylvania PUC, we assume the projected revenue is based on customer growth, also known as revenue per customer (RPC) decoupling and only revenue from the volumetric billing determinant is considered. We model RPC decoupling as yearly changes in customer volumetric rates to allow the actual revenue to meet the projected revenue. That is, if the volumetric revenue is below the projected revenue allowance, volumetric rates are adjusted to meet the allowed revenue. If revenue is above the projected revenue allowance, rates are decreased. In practice, decoupling is performed with balancing accounts to reduce frequent changes to customer rates.

6.6. Avoided Costs

6.6.1. Avoided Energy Costs

6.6.1.1. Pennsylvania Alternative Energy Portfolio Standards

Pennsylvania has an Alternative Energy Portfolio Standards (AEPS) composed of two tiers of energy products. Tier 1 is composed mostly of renewable energy resources such as wind, hydro, biomass and geothermal. It includes a solar carve out that reaches 0.5% in 2021 (PA Public Utility Commission 2016). Tier 2 is composed of waste coal, municipal solid waste and other alternative energy resources. (PA Public Utility Commission 2016). In 2016, the average AEC price of all tiers is $8/MWh, and the AEPS obligation is 13.7% of sales (PA Public Utility Commission 2016). The AEPS grows 0.5 percentage points per year until 2021 and we assume the AEC price stays constant. We do not model any effect of higher solar penetrations on the AEPS AEC price, although it is possible that AEPS targets could be one mechanism to achieve higher penetrations, or that higher solar penetrations could reduce AEPS REC prices.

6.6.1.2. Demand Reduction Induce Price Effect (DRIPE)

Figure 5 shows modeled price suppression of LMPs for several weeks in in the PECO Zone in the summer. Figure 25, below, shows the DRIPE for a full year. The reduction in price is small reflecting the relatively small portion of demand that Pennsylvania (~ 30 peak GW) is of the entire PJM service territory (~ 160 GW). Initially, reduced demand and the price suppression will avoid energy costs and contribute to a relatively high VOS. As the penetration increases and as the LMPs diminish during times of solar output, the energy VOS will also diminish.

Strictly speaking, the DRIPE is not an avoided cost but rather a wealth transfer from producers to consumers. The energy VOS, for example, includes avoided fuel costs and reflects a reduction in consumption. In contrast, the DRIPE does not reflect a reduction in fuel consumption. It only affects the price we pay for that fuel and will make generator operations less economic. PECO does not own generation, so from their perspective and from their ratepayers' perspective, energy costs are reduced. In the long run, however, downward pressure on LMPs may result in higher capacity market prices or ancillary services. We do not model these market dynamics, but we do include scenarios without the DRIPE in our sensitivity analysis.

A better approximation DRIPE would entail running optimal powerflow for different solar penetrations so that the PECO Zone LMP (and not the PJM wide marginal price) could be used to calculate the DRIPE. This method is beyond the scope of the study.

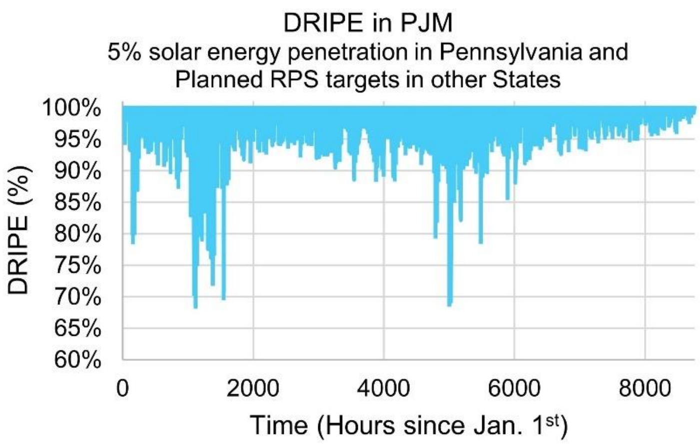

Figure 25: Hourly Demand Reduction Induced Price Effect (DRIPE) after solar rollout is complete (in 2030) using 2016 loading and solar profiles.

Using NREL's Physical Solar Model, a combination of several locations throughout Pennsylvania and PJM (Harrisburg International Airport, Pittsburgh International Airport, Philadelphia International Airport, Delaware, Maryland, New Jersey, and Washington DC) are averaged to find a representative PJM solar profile. The PJM solar profile is used to estimate how solar will reduce PJM's load profile. The hourly marginal price is recalculated with the demand reduction caused by solar. We estimate the DRIPE as the fraction of PJM wide marginal price with solar and without solar. The DRIPE is calculated for several penetrations. Interpolation is used to estimate the various yearly penetrations as solar is rolled out to meet the 2030 target. Figure 25 shows the DRIPE at a 5% energy penetration of solar in Pennsylvania using weather and loading profiles from the year 2016.

6.6.2. Avoided Transmission Costs

6.6.2.1. Growth Related Transmission Capex

We estimate yearly growth-related transmission capex from PJMs Transmission Cost Information Center (TCIC) spreadsheet (PJM 2019). To be considered as growth-related, transmission projects must fall under the following project drivers: Baseline Load Growth Deliverability & Reliability, Generator Deactivation. Additionally, the project description must include a reference to adding new equipment or increasing the rating on equipment. We did not consider projects with other drivers: Congestion Relief Economic, Customer Service, Equipment Material Condition, Performance and Risk, Operational Performance, and Short Circuit. Although Congestion Relief Economic is related to growth, we assume that the transmission value associated with these projects is already embodied in PECO's LMPs. Overall, we estimate that PECO has $6MM of growth-related projects per year that are included in its rate base and PECO pays PJM for an additional $46MM of growth-related projects per year (20% of annual transmission expenses).

6.6.2.2. Solar Profile

The Transmission capacity credit describes the ability of solar to reduce PECO's yearly non-coincident peak Using NREL's Physical Solar Model, a combination of locations in PECO's service territory (Peach Bottom, Doylestown, Philadelphia International Airport) are averaged to find a representative solar profile and to estimate how solar will reduce PECO's load profile.

6.7. Distribution Interconnection Model

We modeled four PECO feeders with varying solar penetrations and different smart inverter options. Modeling PECO's feeders required several steps. First, PECO selected four feeders that are representative of their service territory. Second, we converted PECO's feeder models from CYMDIST, which performs only static powerflow analysis, to GridLab-D, which can also do sequential time-series powerflow analysis. Third, we populated the GridLab-D feeder models with representative secondary networks and weather dependent building models, ensuring that the total simulated substation load was similar to SCADA readings and that the maximum simulated spot loads were similar to the spot load values in PECO's models. Fourth, we populated the GridLab-D feeder models with residential and commercial solar PV by drawing from a probability distribution of the nominal capacity (kW_{AC}) of recent solar installations. Fifth, we simulated varying penetrations of solar on the models with different voltage excursion mitigation scenarios. In our reconductoring scenario, if a solar installation caused a voltage excursion, the capacity of the service drop conductor connecting the solar installations was increased by 100 amps. In our smart inverter scenario, we connected smart inverters to all solar installations. These steps are described in more detail below.

6.7.1. Feeder Selection

We used four feeders that are representative of the PECO service territory. Feeders were chosen with features common to the PECO service territory that may make it harder to integrate high penetrations of solar. Key features of the feeders are summarized in Table 4.

Table 4: Summary of PECO feeders used in analysis.

Feeder Name	Voltage Level	Max Length	Number of Nodes	Peak Load	Losses at Peak

Feeder 1	13.2 kV	4.7 miles	473	6.2 MVA	9.4%
Feeder 2	33 and 4 kV	14 miles	3400	17 MVA	10%
Feeder 3	4kV	2.9 miles	200	2.1 MVA	8.6%
Feeder 4	4 kV	5.4	800	2.3 MVA	6%

6.7.2. Feeder Conversion

We used the National Rural Electric Cooperative Association's (NRECA)'s Open Modeling Framework (OMF), a suite of open source analysis tools for distribution networks to convert PECO's CYMDIST models to an equivalent GridLab-D static powerflow snapshot. Figure 26 shows a comparison of the cyme voltages with the converted GridLab-D voltages. The maximum difference between the results is approximately 3%.

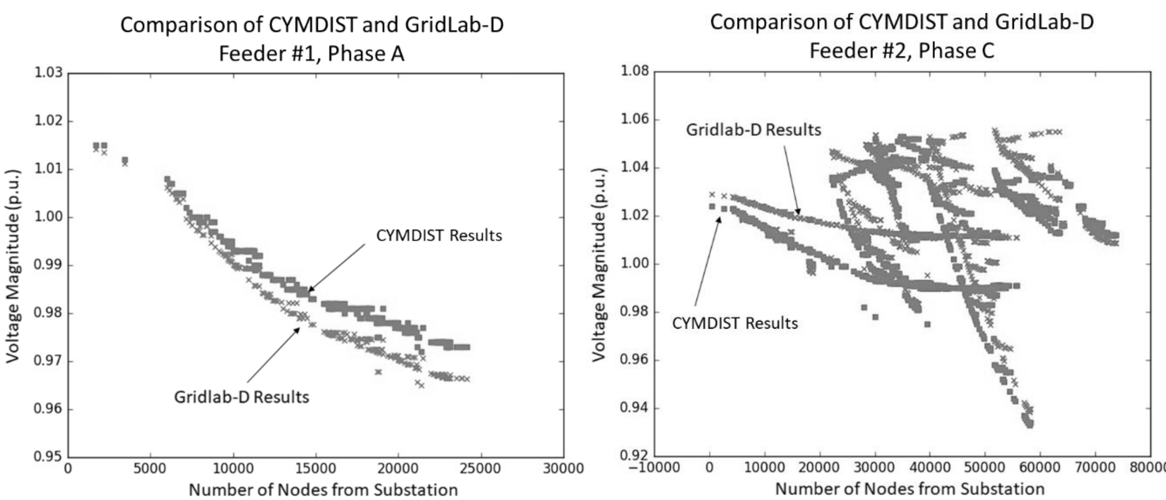

Figure 26: Comparison of GridLab-D and CYMDIST Results.

6.7.3. Secondary Network Modeling

Figure 27 shows the secondary network used in our analysis. A distribution transformer feeds several customers. In PECO's CYMDIST model, all loads connected to the distribution transformer are modeled as a single non-time varying spot load. In our model, the customers are connected to the transformer in a daisy chain sequence with secondary conductors and service drops. The secondary conductors are sized based on the spot load in PECO's CYMDIST models. The service drops are sized based on the peak building load. Table 5 shows the parameters used for the secondary and service drop conductors. The minimum secondary conductor rating is 299 amps and the minimum service drop conductor rating is 90 amps.

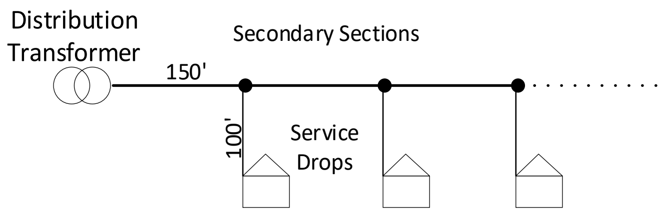

Figure 27: Representative Secondary Model

Table 5: Secondary and service drop conductors. The default secondary rating is 299 amps and is 150 feet. The default service drop rating is 90 amps and is 100 feet.

Current Rating	Size	Stranding	Material	Diameter (in.)	GMR (ft)	Resistance (ohms/mile)
90	4	Class A	AA	0.152	0.007	2.61
202	1/0	Class A	AA	0.368	0.0111	0.97
299	4/0	Class A	AA	0.422	0.0158	0.528
420	3/0	12 STRD	Copper	0.464	0.01559	0.382
500	300,000	30/7	ACSR	0.7	0.0241	0.342
750	605,000	54/7	ACSR	0.953	0.0321	0.1775
1090	750,000	37 STRD	AA	0.997	0.0319	0.0888

To create time-varying loads, we populated the secondary networks with temperature and humidity dependent building models originally made available to the public by Fuller et al. (2012) as part of the PNNL feeder taxonomy. Residential buildings parameters were based on the Energy Information Administration's (EIA) Residential Energy Consumption Survey (EIA 2018). Parameters include: the percentage of homes with air conditioners, HVAC equipment fuel type, hot water heater fuel type, and building R values. Non-weather-dependent load profiles were based on the Bonneville Power Administration's End-Use Load and Consumer Assessment Program (Prat, et al. 1989), and show the characteristic morning and evening peak typical for most residential customers. Commercial buildings were modeled off building codes and end-use metering studies (Fuller, Kumar and Bonebrake 2012). All commercial buildings are modeled as office buildings, big box stores, and strip malls.

To create time-varying loads, the feeder taxonomy was populated with temperature and humidity dependent building models and made available to the public by Fuller et al. (2012).

Residential buildings parameters were based on the Energy Information Administration's (EIA) Residential Energy Consumption Survey (EIA 2018). Non-weather-dependent load profiles were based on the Bonneville Power Administration's End-Use Load and Consumer Assessment Program (Prat, et al. 1989), and show the characteristic morning and evening peak typical for most residential customers. Commercial buildings were modeled off building codes and end-use metering studies (Fuller, Kumar and Bonebrake 2012). All commercial buildings are modeled as office buildings, big box stores, and strip malls.

We used a genetic algorithm to adjust residential and commercial building parameters so that the simulated feeder load time-series matched hourly SCADA readings. Our objective function minimized the difference between the simulated and SCADA load profiles from May-September 2016. The decision variables were the air conditioning coefficient of performance, insulation R values, cooling set points, floor areas, scaling factors for predefined temperature independent ZIP load profiles, the proportion of commercial buildings modeled as strip malls, office buildings, and big box stores, the percentage of residential homes with air conditioners, and the percentage of residential homes with hot water heaters.

Figure 28 compares our simulated load with SCADA load in the year 2016 for both feeders. Simulated loads and SCADA readings are close on Feeder #1. On Feeder #2, the simulated load profiles underestimate the peak load, but the peak simulated hour, which is important for estimating solar's effective capacity, is still close to the observed hour using SCADA data. Feeder #2 is an industrial feeder and the error is likely caused by exogenous effects, such as shifting factory production schedules. These exogenous effects are difficult to include in GridLab-D's weather-dependent models.

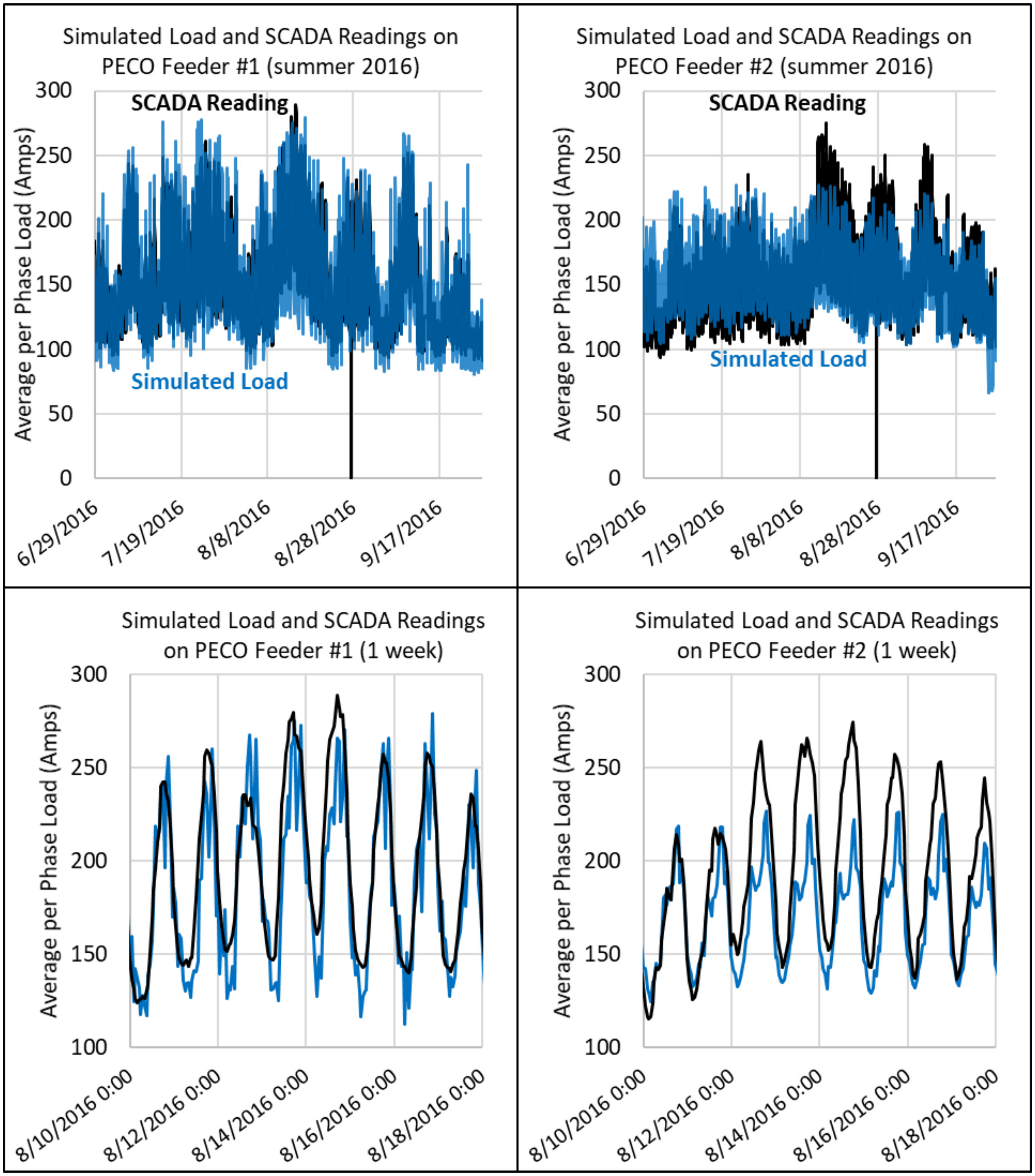

Figure 28: Comparison of SCADA substation loading from eastern utility and modeled loading using GridLab-D. GridLab-D building models were tuned to capture the weather dependence of the feeder load. The simulated peak hours closely matched SCADA readings. On Feeder #2, non-weather exogenous effects cause the simulated peak to underestimate several peaks.

We did not have hourly SCADA readings for Feeder #3 and Feeder #4, so the building parameters in these feeders were populated with the same parameters in Feeder #1 and

Feeder #2. After matching the simulated substation load with the SCADA substation load, we scaled the floor area and ZIP load parameters so that the maximum time varying loads matched PECO's spot loads. Deviations in the floor area was limited to 30%.

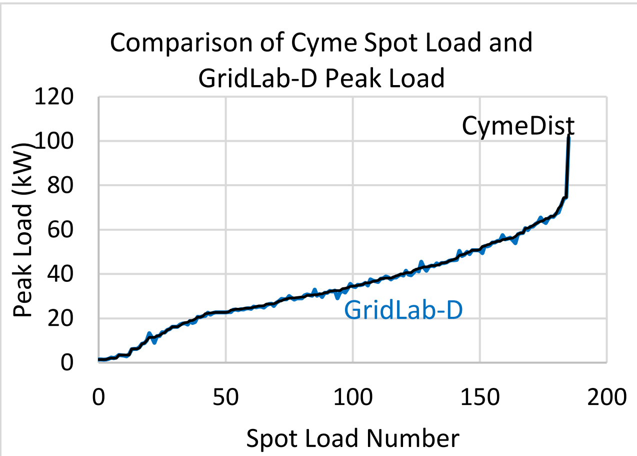

Figure 29: Comparison of CYMDIST non-time varying spot load with the maximum GridLab-D peak.

6.7.4. Solar Modeling

Each feeder was populated with solar panels to create peak solar penetrations (solar nominal AC capacity divided by the peak feeder load) ranging from 1% to 50%. The nominal capacity(kW_{AC}) of the solar installations were found by sampling from the capacity distribution of recent residential and solar installations. These distributions are shown in Figure 30. We used the stats package in the Python™ SciPy[4] library to fit each distribution. The distribution of residential installations is modeled with a lognormal distribution and the commercial installations is modeled with a gamma distribution. For the residential lognormal distribution, the shape, loc, and scale parameters are 0.43, -0.74 and 6.9. For the commercial gamma distribution, the shape, loc, and scale parameters are 0.58, 0, and 117. 96% of installations are on residential loads.

[4] https://www.scipy.org/

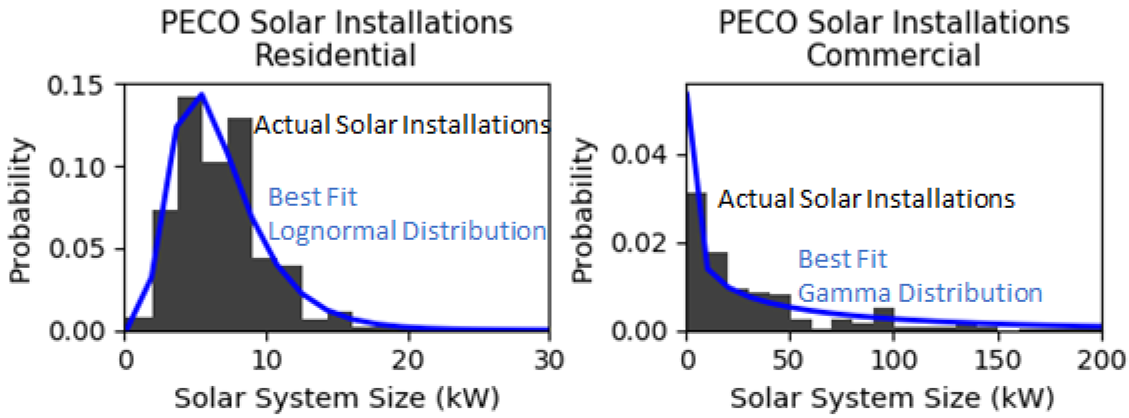

Figure 30: Histogram and probability distributions for recent nominal solar capacity (kW_{AC}) installations in the PECO service territory. For the residential lognormal distribution, the shape, loc, and scale parameters are 0.43, -0.74 and 6.9. For the commercial gamma distribution, the shape, loc, and scale parameters are 0.58, 0, and 117.

Each solar installation was drawn from the probability distribution and placed on a building with the closest matching roof size. Floor area was used to estimate total roof space using the method proposed by Butler (2018). The available roof space was found by scaling the total roof space by 40%. All panels are flat plate and monocrystalline with a 30 degree tilt. Inverters have an efficiency of 96% and a sizing factor of 1.4

We used solar radiation and weather data from NREL's National Solar Radiation Database, Physical Solar Model-Version 3 (PSM-V3) (NREL 2018). PSM-V3 estimates solar irradiance from satellite data from 1998-2016 with a geographic resolution of 4-km by 4-km and a 30-minute time resolution (Habte, Sengupta and Lopez 2017). Compared to ground measurements, mean bias errors are approximately ±5% for GHI and ±10% for DNI. RMS errors are as high as 20% for GHI and 40% for DNI.

6.7.5. Voltage Violation Mitigation Strategies

We tested several methods for mitigating voltage excursions. PECO currently reconductors service drops when solar installations cause high voltages. To model this practice, when a high voltage was detected we replaced the conductor with the conductor with the next largest ampacity (shown in Table 5). In the smart inverter scenarios, we placed smart inverters on every solar installation. Volt/Var with real power priority, Volt/Var with reactive power priority, and Volt/Watt were considered. Figure 31 shows the set points for both Volt/Var smart inverters and the Volt/Watt setting.

Figure 32 and Figure 33 demonstrate the effectiveness of the smart inverters. In Figure 32 the solar profile is compared to the total number of voltage violations on a feeder. There are more voltage violations when the solar output is larger. In Figure 33, a house is shown where both Volt/Var and Volt/Watt smart inverters eliminate a voltage violation caused by solar.

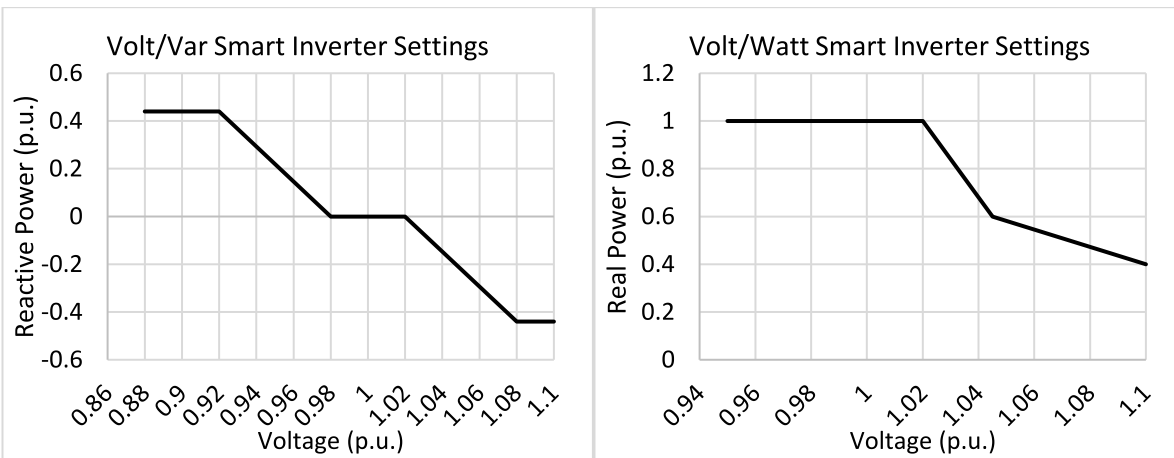

Figure 31: Volt/Var and Volt/Watt smart inverter settings.

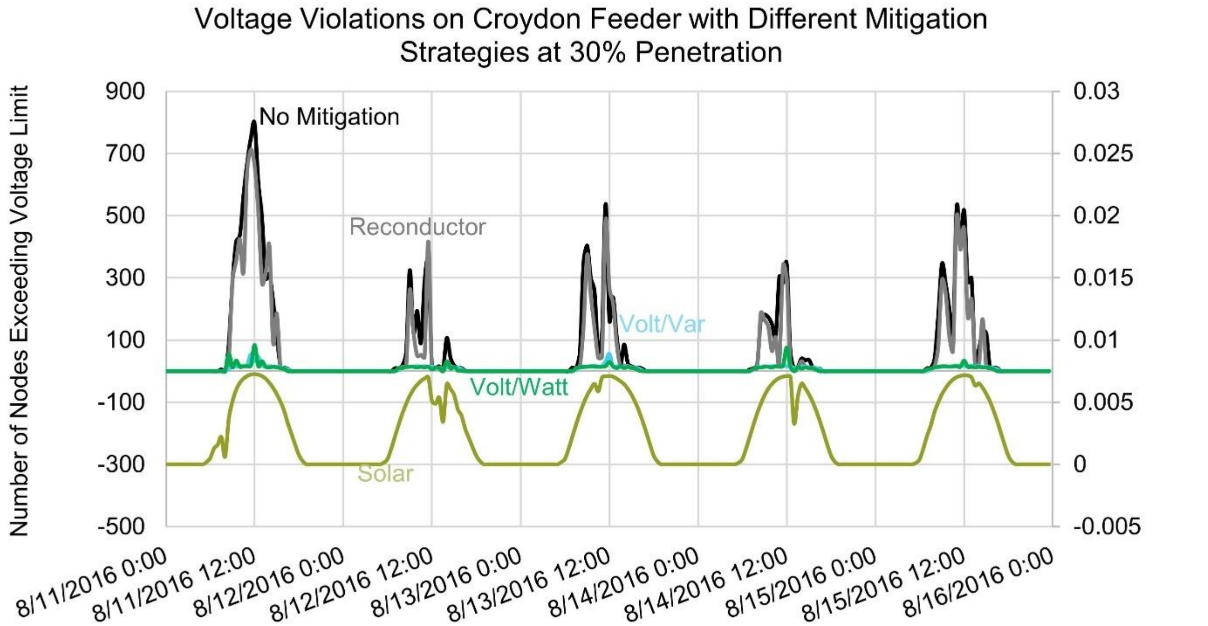

Figure 32: Voltage violations on a PECO feeder in the summer. There are more voltage violations when the solar output is greater. Volt/Var and Volt/Watt smart inverters eliminate most of the violations.

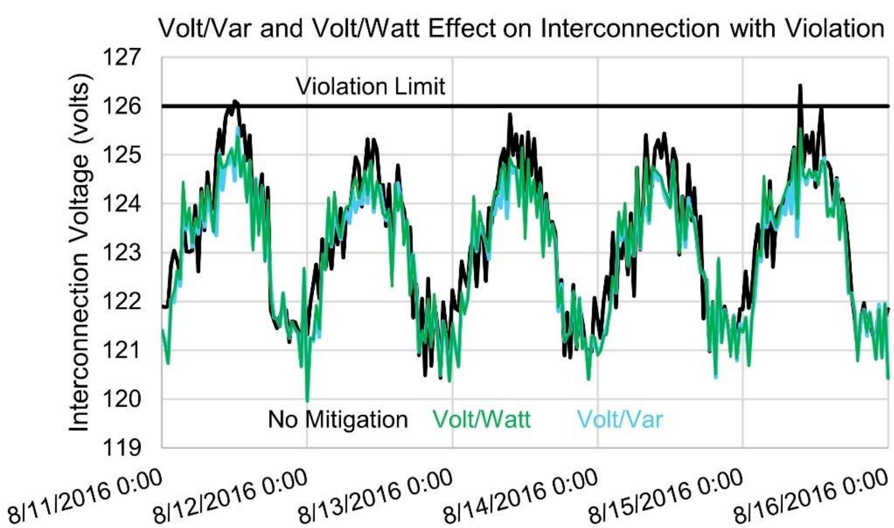

Figure 33: A house where a smart inverter eliminates the voltage violation at the interconnection point.

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