Putting the Potential Rate Impacts of Distributed Solar into Context

Authors:

Galen Barbose

Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

January 2017

BERKELEY LAB
Lawrence Berkeley National Laboratory

Disclaimer

Acknowledgements

Table of Contents

Table of Figures

List of Tables

1. Introduction

The rapid growth of distributed solar in a number of states has raised questions about its potential effects on retail electricity prices, prompting concerns by some utilities and stakeholders about cost-shifting between solar and non-solar customers. These concerns have, in turn, led to a proliferation of proposals to reform retail rate structures and net metering rules for distributed solar customers, often extending to states that have yet to witness significant solar growth. These proposals have typically been met with a great deal of contention and often absorb substantial time and administrative resources, potentially at the expense of other issues that may ultimately have greater impact on utility ratepayers. Given these inevitable tradeoffs, state regulators might ask: How large could the effect of distributed solar on retail electricity prices conceivably be? And how does that compare to the many other factors that also influence electricity prices—and over which state regulators and utilities might also have some control?

This paper seeks to address these questions, with the aim of helping regulators, utilities, and other stakeholders gauge how much attention to devote to evaluating and addressing possible impacts of distributed solar on retail electricity prices. The objective is neither to dismiss concerns nor to raise alarm, but rather to provide some metrics and benchmarks that could help to set priorities. To be sure, in focusing on the potential effects on retail prices, we address just one motivation behind rate reforms for solar customers— namely, concerns about cost-shifting between solar and non-solar customers. Other motivations, including impacts on utility shareholders and economic efficiency, are also relevant and may ultimately provide a more compelling rationale for retail rate reforms, but are outside the scope of this paper. Several other important limitations to the study scope are noted in the text box to the right.

We begin by discussing historical trends in U.S. and regional average retail electricity prices, key drivers for those trends, and current projections. Next, we present a simple, fundamentals-based model for approximating the effects of distributed solar on retail electricity prices, and use that model to gauge the magnitude of effects that might plausibly occur under current and

> **Limitations to the Scope of this Paper**
>
> This paper presents illustrative comparisons between the effects of distributed solar and other drivers of retail electricity prices. **It does not:**
>
> - **Address distributed energy resources as a whole.** While this paper focuses specifically on distributed solar, retail rate reforms in some states may be motivated by distributed energy resources more broadly and by other technologies that enable customer price-responsiveness.
> - **Provide state- or utility-specific analysis.** The analyses presented here are based on U.S. average or otherwise illustrative conditions, and draw from a variety of pre-existing studies. The paper may inform, but is not a substitute for, detailed state- or utility-specific studies.
> - **Support any particular approach to defining the value of solar.** This paper shows, generically, how the effects of distributed solar on retail electricity prices are a function of the value of solar to the utility. However, the paper makes no assumptions or conclusions about how to estimate that value.
> - **Provide a cost-benefit analysis of distributed solar or any other type of policy or resource.** This paper focuses narrowly on retail electricity price effects. It does not address the full set of costs and benefits relevant to evaluating the resources and policies discussed.

forecasted penetration levels. We then discuss a number of other important drivers for future retail electricity prices, including: energy efficiency programs and policies, natural gas prices, renewables portfolio standards, state and federal carbon policies, and electric industry capital expenditures. We characterize the potential effects of each of those drivers on future retail electricity prices, based on a combination of literature review and back-of-the-envelope style analyses. Finally, in the Summary and Conclusions section, we directly compare the potential retail price effects of distributed solar and each of the other issues discussed, and offer high-level conclusions.

2. U.S. Retail Electricity Prices: Historical Trends and Current Projections

To provide some historical context to questions about the possible effects of distributed solar on retail electricity prices, it is useful to begin by reviewing how prices have evolved over time and where they are currently projected to go. As shown in Figure 1, U.S. average retail electricity prices, in real (inflation-adjusted) terms, have fluctuated over time, with extended periods of increasing and decreasing prices.[1] Average prices in 2015 were nearly identical to the long-term historical average since 1960 (10.4 cents/kWh, in real 2015$), and were well below the highs of the early 1980s. Nominal electricity prices—what consumers directly observe—have generally risen over time, albeit with several prolonged periods of relatively stable prices. On average, retail electricity prices have risen in nominal terms by 3.2% (or 0.16 cents/kWh) per year since 1960, roughly equal to the average rate of inflation over that period. Nominal electricity prices and inflation have not moved in lock-step though, with electricity prices rising more slowly than inflation in some periods, and considerably faster in others, as shown in Figure 2.

Cents/kWh
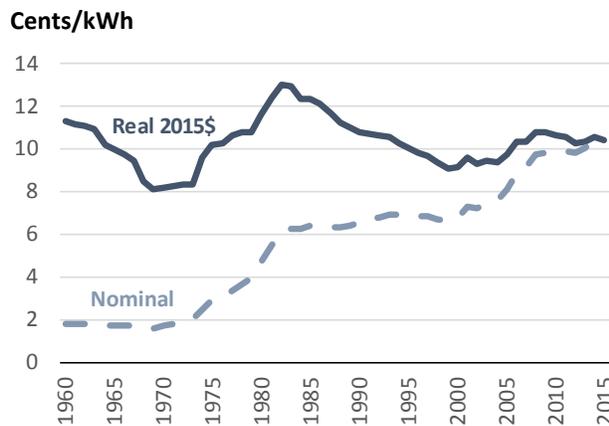
Notes: Represents U.S. average retail electricity prices across all customer segments and utilities, as reported by EIA (2012, 2015c, 2016e). Converted to real dollars based on GDP price deflator (BEA 2016).

Figure 1. Historical trends in U.S. average retail electricity prices

Annual growth rate (5-yr rolling average)
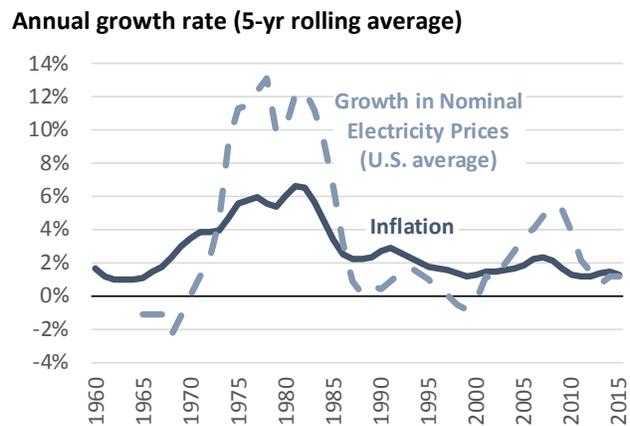
Notes: Growth rates for nominal electricity prices and inflation both calculated as a rolling 5-year compound annual growth rate. See Figure 1 notes for sources.

Figure 2. Escalation of nominal electricity prices compared to inflation

The first significant rise in electricity prices (in both real and nominal terms) coincides with the oil price shocks of the 1970s and the resulting increases in fuel prices, inflation, and interest rates (Joskow 1989 and Kahn 1988). High interest rates especially impacted construction costs for the many nuclear power plants built during this era, some of which also suffered construction delays, leading to steep rate

---

[1] Average retail electricity rates—that is, total revenues divided by total sales—are an admittedly blunt metric, glossing over distinctions among customer classes and between investor-owned and publicly owned utilities, and ignoring distinctions in retail electricity rate structures that often include non-volumetric charges. Also important to note is that trends in average electricity prices do not necessarily mirror trends in average customer bills or costs, as can be particularly germane when discussing demand-side resources, such as energy efficiency or distributed solar.

increases as those costs were passed into utilities' rate bases (Hirsh 1999). Slowing growth in electricity sales further exacerbated the effects of capital cost escalation on electricity prices, as utilities' increasing revenue requirements were spread across fewer (or more slowly growing) units of electricity sales. As a result of this confluence of factors, U.S. average retail electricity prices rose by 4% per year from 1973-1983, in real dollars (and by 12% per year in nominal terms). As fuel prices and inflation rates began to subside in the mid-1980s, and as electricity sales growth recovered, U.S. average electricity prices resumed their downward trajectory (in real dollars, and remained relatively flat in nominal terms) until roughly the end of the millennium.

Starting around 2000, electricity prices again hit an inflection point and began an upward bend. The trend extends across most regions, albeit to varying degrees. As shown in Figure 3, most regions saw at least a 1-2 cent/kWh increase in average retail prices over the 2000-2015 period, and in some cases larger price swings in the intervening years. A relatively sizeable literature has sought to explain retail electricity pricing dynamics over the past two decades, generally in connection with restructuring of wholesale and retail electricity markets. As summarized by Morey and Kirsch (2016), these studies draw varying conclusions about the effects of deregulation: in some cases finding evidence that it reduced retail electricity prices (relative to what they otherwise would have been), in other cases finding no such effect, and in yet other cases finding that the effects have varied (e.g., depending on retail switching levels or on whether a state was past its transitional rate-freeze period).

Real cents/kWh (growth from 1990)
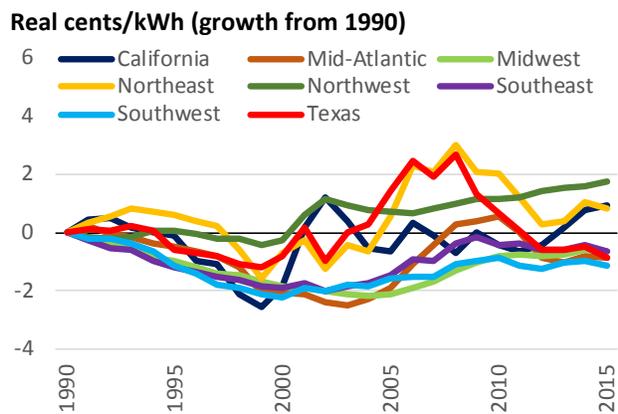
Notes: Values represent the change in price relative to 1990. See Figure 1 notes for sources.

Figure 3. Growth in regional retail electricity prices

Real $/MMBtu
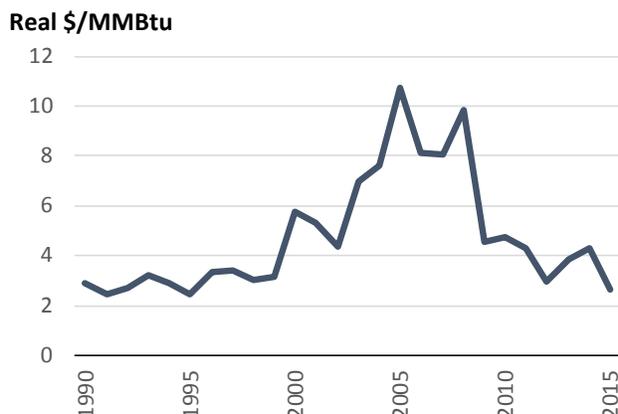
Notes: Annual average of daily prices for NYMEX Henry Hub futures contracts for delivery in the following month.

Figure 4. Annual average natural gas prices

Many of the same studies also highlight the impact of natural gas prices, which were especially volatile over this period. As shown in Figure 4, gas prices rose sharply from 2000 through 2008, before dropping back down with the recession and expansion of shale extraction. The effects on regional electricity prices are most apparent for the Northeast and Texas—both of which show a discernible "bump" in electricity prices, coinciding more-or-less with the years of high gas prices. Those regions both have relatively high proportions of gas-fired generation as well as restructured power markets, which, for reasons discussed in Section 4.2, are particularly sensitive to changes in gas prices. Not surprisingly, econometric analyses of retail prices over this period consistently find strong positive relationships

between state-level electricity prices and either natural gas prices or the proportion of electricity generated from gas (Fagan 2006, Joskow 2006, Ros 2015, Su 2015, Swadley and Yucel 2011, Taber et al. 2006, Zarnikau and Whitworth 2006).

Recent retail electricity price trends have also been driven by capital expenditures (CapEx), which have risen sharply in recent years. Annual CapEx outlays in the electric power sector roughly tripled from 2000 to 2015, with transmission and distribution (T&D) investments representing the vast majority of that growth (EEI 2015, ABB 2016). As these investments enter utilities' rate bases in subsequent rate cases, the associated costs are passed on to ratepayers. Accordingly, annual depreciation and financing-related expenses by major electric utilities grew by roughly 50% over the same time span (ABB 2016).

Reduced growth in electricity sales has also affected the recent trajectory of retail electricity prices. Almost every region in the United States has seen effectively zero growth in electricity sales since 2008 or earlier, as shown in Figure 5. Although growth rates have been steadily declining over a longer period of time, such an extended period of flattened demand is wholly unprecedented, with the closest analogue being two brief periods of dampened growth in the aftermath of the 1970s' oil price shocks. This recent episode of low demand growth is partially the result of the recession, though other factors have also clearly played a role (Faruqui 2013).

Indexed retail electricity sales (1990=1)
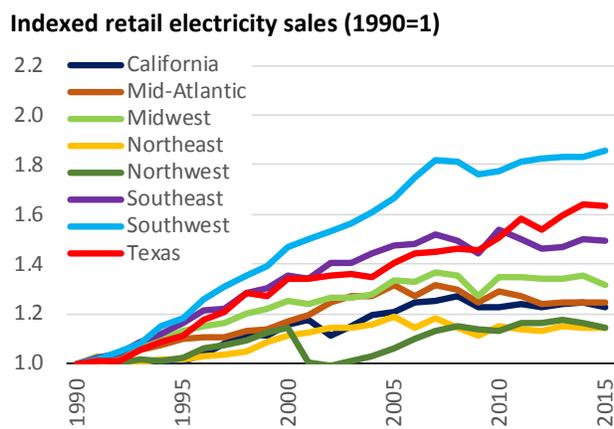
Notes: Data represent total retail electricity sales, including both bundled and energy-only sales, as reported by EIA (2015c, 2016e).

Figure 5. Growth in regional retail electricity sales

Indexed retail electricity sales (1990=1)
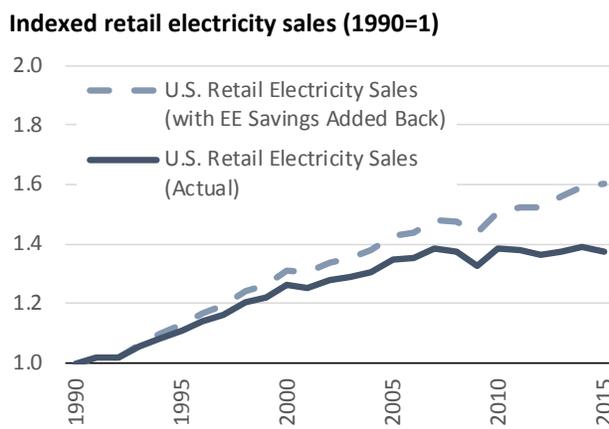
Notes: Savings from federal appliance standards based on Meyers et al. (2016). Savings from utility ratepayer-funded programs are based on ACEEE data (e.g., Berg et al. 2016) and decayed over time to reflect a 10-yr. avg. measure life. The figure does not account for possible rebound effects.

Figure 6. Impact of energy efficiency programs and policies on U.S. retail electricity sales

One key contributor has been increasing energy efficiency. As shown in Figure 6, federal appliance efficiency standards and utility ratepayer-funded energy efficiency (EE) programs have significantly slowed retail electricity sales growth. The erosion of sales growth has accelerated in recent years, as new standards have taken effect and utility programs have become more aggressive. In total, federal efficiency standards and utility efficiency programs reduced U.S. retail electricity sales by an estimated 14% in 2015, relative to what they otherwise would have been (but without accounting for possible

rebound effects). State appliance standards and building codes, not counted here, would add further to that total. In the absence of those efficiency interventions, U.S. retail electricity sales would have grown by roughly 1.3% per year since 2000: still below historical growth rates (e.g., 2.3% per year from 1990-2000), but substantially greater than actual growth over that period (0.6% per year).

The precise impact of declining sales growth on retail electricity prices can be difficult to assess, as its effects can work in opposing directions. On the one hand, slower growth allows utilities to purchase less fuel and, over the long-term, defer some investments that they might otherwise need to make. Slower demand growth also puts downward pressure on wholesale electricity prices in competitive markets, at least in the short-run. On the other hand, reduced sales can push prices upward in the near-term for regulated services, as fixed or growing infrastructure costs are spread over a more slowly growing quantity of sales. Thus, even if customer bills are lower, the price per kilowatt-hour may be higher. Consistent with this latter dynamic, Morey and Kirsch (2013) estimated that recession-induced reductions in electricity sales increased state-level residential and commercial electricity prices by approximately 0.8 cents/kWh, on average.

State and regional clean energy policies have also been linked to increases in retail electricity prices, though most available evidence points to relatively limited impacts to-date. In particular, analyses of state renewables portfolio standards (RPS) have generally suggested effects on the order of 0.5 cents/kWh or less in recent years, though those impacts can be greater in states with retail choice or more-stringent RPS standards, and have grown over time as RPS percentage targets rise (Barbose 2016, Morey and Kirsch 2013, Tra 2016, Wang 2014). More details on the historical effects of RPS policies are provided in Section 4.3. Greenhouse gas cap-and-trade programs have also been established in California and the Northeast—however the effects of those policies on retail electricity prices also appear to have been modest thus far, largely due to low emissions allowance prices and the fact that revenues from allowance sales are often partially credited back to ratepayers (CARB 2016, RGGI 2016a).

Cents/kWh (U.S. average)
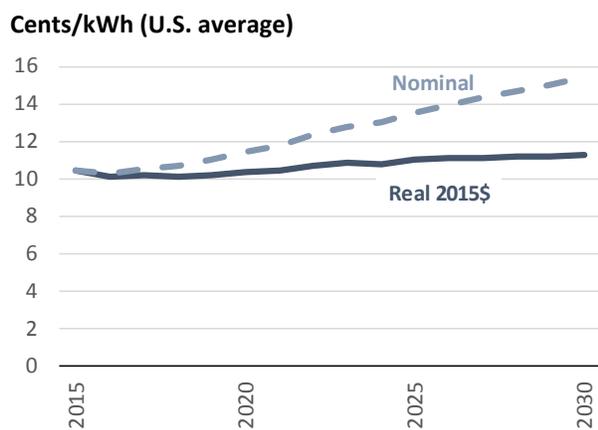
Notes: Projected U.S. average retail electricity prices based on EIA's 2017 Annual Energy Outlook reference case (EIA 2017).

Figure 7. Projected U.S. average retail electricity prices

Cents/kWh (total increase from 2015-2030)
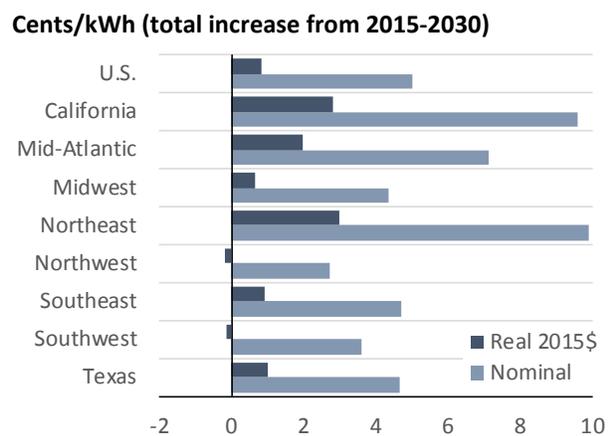
Notes: See Figure 7 for source. Based on projected retail prices for EIA Electricity Market Module regions, aggregated into the larger regional groupings shown here.

Figure 8. Projected growth in regional electricity prices

These many considerations aside, it is clear that retail electricity prices in the United States have generally been on a slight upward trajectory since 2000, even after adjusting for inflation, marking a departure from the earlier era of steadily declining prices. Current projections suggest that those recent trends are not an intermittent episode, but potentially the beginning of a longer-term shift. As shown in Figure 7, EIA's most-recent reference case forecast projects that U.S. average retail electricity prices will continue to gradually rise, increasing by just under 1 cent/kWh in real terms (and 5 cents/kWh nominal) through 2030, similar to the pace of escalation since 2000. As shown in Figure 8, price escalation is projected to extend across most regions, though to varying degrees, with the largest projected increases in the Northeast and California.

Future electricity prices are, of course, highly uncertain, and key sources of uncertainty—including many of the same drivers discussed above—are explored in Section 4 of this paper. Those uncertainties, combined with the end to the era of steadily declining prices, may heighten sensitivity about possible price effects associated with the growth of distributed solar. So how large might those effects be?

3. Scaling the Effects of Distributed Solar on Retail Electricity Prices

Much debate has occurred around the existence and size of any cost-shifting from distributed solar, particularly for solar compensated via net energy metering (NEM) with volumetric retail rates. These debates have focused to a large degree on how to properly value the costs and benefits of distributed solar. One threshold issue is the time horizon: whether to consider only short-run avoided costs from distributed solar, consisting mostly of avoided fuel and power purchase expenses, or to also consider longer-term avoided costs, including potential deferral of generation and T&D investments. Another threshold issue is the scope of benefits to consider: for example, whether to focus only on avoided costs directly incident on the utility, or to also include broader societal benefits, such as avoided environmental externalities. Beyond those are many narrower, though also important, methodological issues related to how to properly evaluate specific costs and benefits.

For the present purposes, we abstract from those technical and policy questions and show, generically, how the effect of distributed solar on average retail electricity prices is a function of three basic drivers: its penetration level, the net avoided costs to the utility, and the compensation rate provided to distributed solar customers. Understanding these basic functional relationships can help to scale expectations about the magnitude of any plausible impacts on electricity prices, without necessarily having to arbitrate all the technical details of how to value distributed solar.

We focus specifically on cost-of-service based pricing, where total utility revenues are approximately equal to total utility costs, and average retail electricity prices are equal to utility revenues divided by sales.[2] In order to generalize the effects of distributed solar, we specify the three key drivers as follows, each of which is expressed as a ratio or percentage term:

- **Penetration level** is expressed in terms of total distributed solar generation as a percentage of total retail electricity sales.

- **Net avoided costs** are expressed as the value of solar (VoS) to the utility (i.e., benefits minus costs) relative to the utility's average cost of service (CoS). VoS refers to the *net* avoided costs to the utility per unit of solar generation, and CoS refers to the utility's average all-in cost per unit of retail sales. For the purpose of estimating retail price effects, the VoS should consider only costs and benefits directly incident on utility ratepayers, but may be based on either short- or long-run avoided costs, depending on whichever time horizon is deemed most relevant.[3] In

---

[2] The assumed equivalence between utility revenues and costs does not hold perfectly, particularly in the short-run between utility rate cases, but should be reasonably accurate over the longer term as rates are re-set in successive rate cases. Other persistent exceptions may still exist, though, for example due to disallowed costs and performance incentives.

[3] Although a broader scope of costs and benefits—such as non-energy benefits and societal costs and benefits—may be relevant in other contexts and to policy-making more generally, they are not directly relevant to evaluating the effects on electricity prices.

cases were only short-term avoided costs are considered (e.g., avoided fuel and power purchase expenses), the VoS/CoS ratio would be relatively low. If additional avoided costs are deemed appropriate to include, as may be the case under a longer term analysis, the VoS/CoS ratio would be greater.

- **Solar compensation rate** is the payment or bill savings per unit of solar generation, relative to the CoS. Under full NEM with flat volumetric rates and no fixed customer charges or demand charges, the customer is effectively paid the average retail electricity price for all solar generation. In this case, the compensation level is equal to roughly 100% of the CoS (assuming the retail price is reflective of the CoS). Under other crediting mechanisms or rate designs, the compensation might be higher or lower than the CoS. For example, under rate structures with fixed charges or demand charges, as are common for commercial customers and increasingly so for residential customers, the solar compensation rate would be less than 100% of the CoS.

Relying on those three terms, we can then express the percentage change in average retail electricity prices resulting from distributed solar, as follows (see Appendix A for the derivation):

$$Percent\ Change\ in\ Retail\ Electricity\ Price = \ Penetration\ \times\ \left[\frac{Solar\ Comp.\ Rate}{CoS} - \frac{VoS}{CoS} \right]$$

To be sure, this simplified construct ignores various complexities of electric ratemaking processes, not least of which being the lag between the time that costs are incurred and when they are added into rates. To the extent this simplification introduces bias, it would likely be to overstate the effects. In addition, although it can be used to estimate an average effect across all customers, the above expression may be more usefully applied on a customer-class specific basis, given differences between residential and commercial rate structures, and the manner in which revenue requirements are allocated to individual customer classes.

Percentage change in retail electricity price (y-axis)
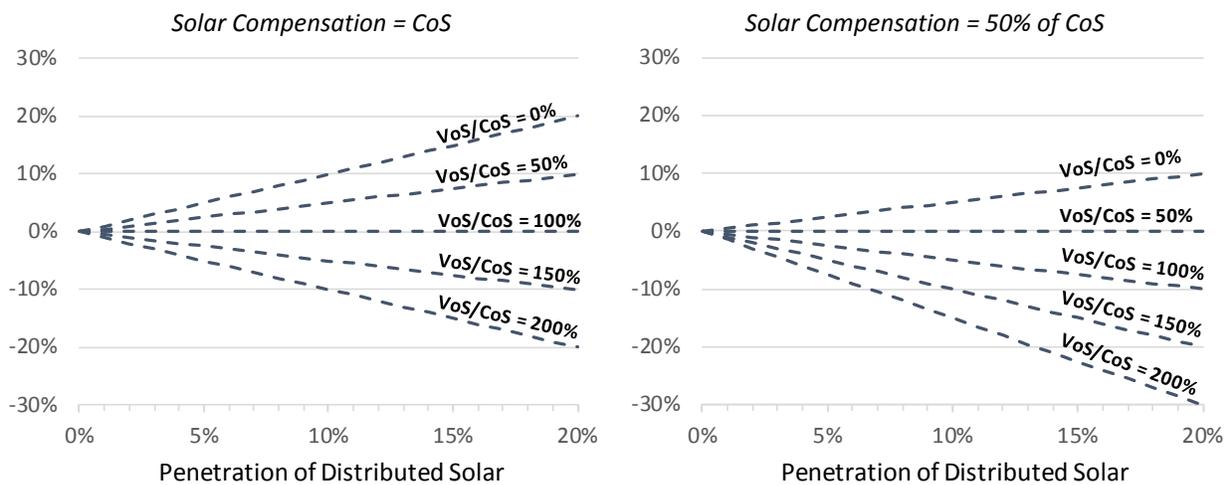
Figure 9. Impacts of distributed solar on average retail electricity prices: A simple model of underlying drivers

Based on the expression above, the family of curves shown in Figure 9 illustrate the percentage change (either increase or decrease) in average retail electricity prices resulting from varying levels of distributed solar. The figure on the left represents the case where solar compensation is equal to exactly the CoS, which corresponds to full NEM with flat volumetric prices and is roughly representative of how residential customers with distributed solar are often compensated. If, for example, the value of solar is equal to half the utility's cost of service (VoS/CoS=50%), then a 10% solar penetration would lead to a 5% increase in retail electricity prices under this compensation regime. The figure on the right corresponds instead to a scenario where solar is compensated at a rate equal to 50% of the utility's cost of service—as would be the case if fixed customer charges were used to meet half the utility's revenue requirement. This figure may also be a better reflection of the relationships under many commercial rate structures with demand charges that comprise a large fraction of the customer bill. At this compensation rate and a VoS equal to 50% of the utility's CoS, distributed solar would have no impact on retail electricity prices, regardless of penetration level. If the VoS were greater, distributed solar would result in a reduction in average retail electricity prices.

The examples above are purely illustrative, but the curves can provide some practical insight if we consider current and projected solar penetration levels. As shown in Table 1, eight utilities reached net-metered PV penetration levels greater than 5% of retail electricity sales in 2015, and four utilities (all in Hawaii) topped 10% of sales within the residential sector. However, the U.S. average penetration was just 0.4% across all electric utilities, and most utilities have yet to reach even one-tenth of that. Thus, for the overwhelming majority of utilities, current PV penetration levels are far too low to result in any discernible effect on retail electricity prices, even under the most pessimistic assumptions about the value of solar and generous assumptions about compensation provided to solar customers (e.g., full NEM with volumetric rates).

Table 1. Top-ten utilities for net-metered PV penetration, as of year-end 2015

Penetration among <u>all</u> customers			*Penetration among <u>residential</u> customers only*		
Utility	State	% of Sales	Utility	State	% of Sales
Hawaii Electric Light	HI	12.4%	Maui Electric	HI	18.0%
Maui Electric	HI	12.1%	Hawaii Electric Light	HI	16.9%
Hawaiian Electric	HI	8.1%	Hawaiian Electric	HI	16.8%
Kauai Island Utility Cooperative	HI	7.9%	Kauai Island Utility Cooperative	HI	10.5%
Otero County Electric Cooperative	NM	5.6%	San Diego Gas & Electric	CA	7.7%
San Diego Gas & Electric	CA	5.5%	City of Moreno Valley	CA	6.5%
Washington Electric Cooperative	VT	5.3%	Pacific Gas & Electric	CA	5.3%
Town of Hardwick	VT	5.3%	Otero County Electric Cooperative	NM	5.2%
Trico Electric Cooperative	AZ	4.1%	Groton Dept. of Utilities	CT	4.5%
Pacific Gas & Electric	CA	3.6%	Southern California Edison	CA	3.9%
	Total U.S.	*0.4%*		*Total U.S.*	*0.6%*

Notes: Based on data for NEM PV capacity and retail electricity sales reported through form EIA-861 (EIA 2016g). Net-metered PV generation is estimated using the PVWatts software with the program's default assumptions (NREL 2016).

Going forward, penetration levels will rise and, for a growing number of utilities, may reach some threshold of significance in terms of the effects on retail electricity prices. Across a collection of recent forecasts, distributed solar generation is projected to reach 1-2% of U.S. retail electricity sales by 2020, 2-4% by 2030, and 4-7% by 2040 (BNEF 2016, EIA 2017, Cole et al. 2016, GTM/SEIA 2016, IHS 2016).[4] The low end of those ranges effectively corresponds to a scenario in which distributed solar capacity additions continue at the same pace as in 2015 (roughly 3 GW per year).

Even with relatively robust growth nationally, high penetration levels are expected to remain concentrated within particular states and regions. Under the National Renewable Energy Laboratory (NREL)'s most recent reference case projection (Cole et al. 2016), three states within the contiguous U.S. surpass 10% penetration by 2030 (not counting Hawaii), and seven others pass the 5% mark, but more than half of all states remain below 1% penetration (see Figure 10). Most utilities are thus quite unlikely to see any appreciable effects of distributed solar growth on retail electricity prices. For example, even if one were to assume that distributed solar had zero net value to the utility (an extremely pessimistic assumption), and that all PV generation was compensated under net metering with purely volumetric retail rates (a relatively favorable scenario for solar customers), a 1% penetration would result in just a 1% increase in average retail electricity prices. Relative to projected U.S. average electricity prices in 2030, this equates to a 0.1 cents/kWh increase. Most utilities are unlikely to see an effect even of this magnitude, given more-realistic assumptions about the value of solar and a lower solar compensation rate for most commercial and many residential customers.
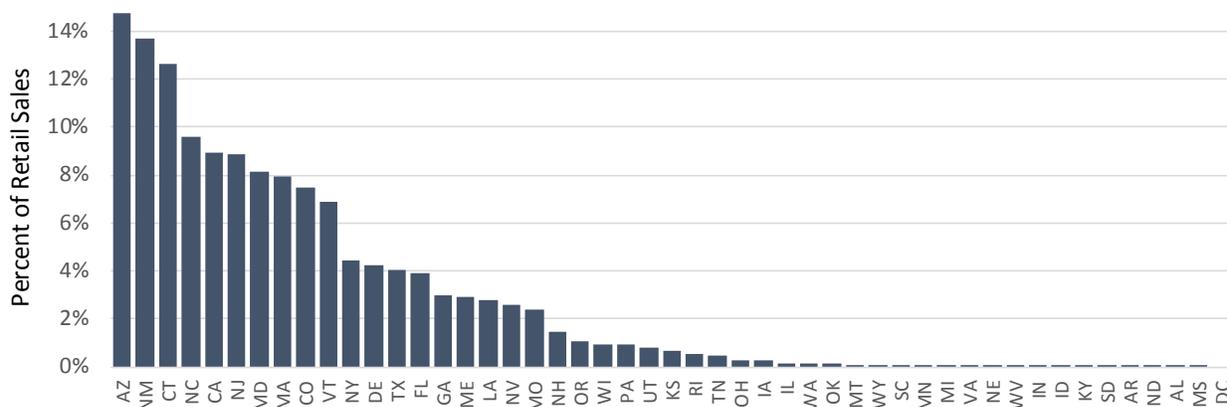
Notes: Based on central case scenario from Cole et al. (2016), which projects solar adoption in the contiguous United States (i.e., excludes Hawaii and Alaska). Penetration levels calculated from projected capacity based on estimated state-level capacity factors (NREL 2016) and retail sales projections developed by applying EMM-level growth rates from the Annual Energy Outlook 2016 reference case (EIA 2016a) to historical state-level retail sales data (EIA 2015c).

Figure 10. NREL-projected rooftop solar penetration levels in 2030

For those utilities that currently, or may in the future, face higher penetration levels, questions about the value of solar become more pertinent. Over the *short-run*, the VoS might be approximated based on a utility's cost of fuel and power purchases, which average 40% of total electric utility expenses

---

[4] These studies all define distributed solar slightly differently; for example, EIA defines it as all solar <1 MW in size, whereas Cole et al. (2016) define it to include all rooftop PV, regardless of size.

nationally (EIA 2015c). Taking a 40% VoS/CoS ratio as an *illustrative* lower bound and assuming full NEM with purely volumetric rates, a utility with 5% solar penetration would see roughly a 3% increase in average retail prices in the short-run, based on the relationships previously described. Outside of Hawaii (which has substantially higher penetration) or California (where residential penetration has reached this level and rates are steeply tiered), few utilities are likely to have witnessed effects on this scale thus far—and even then, the impacts may be concentrated primarily within the residential customer class.

Table 2. Summary of recent value-of-solar studies

Region	Author (Year)	VoS (2015 cents/kWh)		VoS/CoS	
		Core	Core+	Core	Core+
Arizona (APS)	SAIC (2013)	3.7	n/a	31%	n/a
Arizona (APS)	Crossborder Energy (2013a)	24.6	n/a	204%	n/a
Arizona (APS)	Crossborder Energy (2016)	16.9	18.9	144%	161%
California	E3 (2013)	n/a	14.6	n/a	98%
California	Crossborder Energy (2013b)	11.0	20.2	74%	135%
Colorado (PSCo)	Xcel (2013)	7.2	8.4	71%	83%
Maine	Clean Power Research (2015)	13.8	24.3	106%	185%
Massachusetts	Acadia (2015)	15.9	23.2	93%	136%
Mississippi	Synapse (2014)	14.6	17.4	148%	176%
Nebraska	Lincoln Electric System (2014)	3.8	n/a	47%	n/a
Nevada	E3 (2014b)	n/a	13.1	n/a	134%
Nevada	SolarCity/NRDC (2016)	10.3	11.2	109%	118%
North Carolina	Crossborder Energy (2013c)	11.6	12.9	122%	136%
PJM Region	Clean Power Research (2012)	7.5	17.6	51%	121%
Tennessee Valley Authority	TVA (2015)	6.9	7.3	73%	77%
Texas (Austin Energy)	Clean Power Research (2013a)	9.1	11.2	90%	111%
Texas (San Antonio)	Clean Power Research (2013b)	13.3	16.0	143%	173%
Utah	Clean Power Research (2014)	8.3	11.9	97%	139%
Vermont	VT Public Service Dept. (2014)	n/a	24.4	n/a	163%

Notes: "Core" VoS estimates consist of only avoided energy, RPS purchases, generation capacity, reserves, ancillary services, T&D capacity, and losses, and are net of any solar integration costs. "Core+" estimates include additional ratepayer benefits, which, depending on the study, may include items such as: reduced fuel price risk, reduced costs of future carbon regulations, and cost savings associated with reduced wholesale electricity and/or natural gas prices. Broader societal benefits are excluded from both VoS categories, as the present analysis is focused solely on ratepayer impacts. Cells are marked "n/a" if the VoS value was not estimated or identifiable. For studies that included multiple scenarios, we selected the reference case. For studies that presented ranges, we report the mid-point. The VoS/CoS percentages are calculated by dividing the VoS by the average retail electricity price for the corresponding state or utility, in the year in which the study was performed.

Over the *long-run*, a broader set of avoided costs are typically considered. Estimates of the long-term VoS for particular states and utilities vary considerably, as shown in Table 2, reflecting differences in scope, methodology, and the characteristics of regions analyzed (Hallock and Sargent 2015, Hansen et al. 2013). A VoS/CoS ratio can be estimated from each of these studies, by taking the average retail electricity price in each state or utility service territory as a proxy for the average cost of service. Based on this approach, most studies fall within a VoS/CoS range of roughly 50-150% (the 10th and 90th

percentile values are 49% and 146%), when considering only "core" avoided cost categories (see table notes for a list of which items are included in that set). When considering a broader set of potential ratepayer benefits (labeled "core+" in the table), the VoS/CoS ratios are higher, ranging from 90-174% (the 10th and 90th percentile values).

Given these VoS estimates, what effects on retail electricity prices might be observed in those regions with the highest projected levels of distributed solar penetration? As noted, NREL's latest reference case projects that three states in the contiguous U.S. reach 10% penetration of distributed solar by 2030, and similar penetrations might be reached more broadly on a utility-specific basis and among residential customers.[5] At that penetration level and considering a VoS/CoS ratio of 50-150%, the resulting effect on retail electricity prices would be between a 5% increase and a 5% decrease, under full net metering with purely volumetric rates. Assuming an otherwise average price of electricity, this would equate to roughly a 0.5 cent/kWh increase or decrease. By comparison, for the distribution in projected state-level 2030 penetration rates shown in Figure 10, the average retail price impact would be ±0.2 cents/kWh. At current penetration rates, the average retail price impact is ±0.03 cents/kWh.[6]

To be sure, these retail price effects are intended for illustrative purposes only, and in any given instance could be smaller or larger. For example, the estimates presented above are all based on net-metering with fully volumetric prices. In cases where some portion of solar customers take service under rates with fixed charges or demand charges—both of which are already commonplace—the ranges cited above would be shifted downward. At the same time, the preceding estimates draw from VoS studies that, in most cases, are based on current (low) levels of solar deployment. At higher solar penetration levels, the VoS is expected to decline, leading to higher retail price effects (Mills and Wiser 2013). Moreover, the existing VoS studies referenced in the preceding analysis are based on particular utilities or regions, and cannot necessarily be extrapolated to other contexts. Given these limitations and others, more-refined and regionally specific analysis would certainly be needed to accurately estimate the effects of future distributed solar growth on retail electricity prices for any specific utility or state. However, the back-of-the-envelope style calculations presented here offer some rough sense of scale for the possible impacts, and in most situations likely provide a plausible set of bounds.

---

[5] For example, Entergy (Louisiana) and Duke (Indiana) both considered distributed solar penetration levels close to 10% in their latest integrated resource plans (Mills et al. 2016).

[6] The average retail price impacts at current and projected state-level penetration rates are calculated by first computing the impact for each state, applying the same 50%-150% VoS/CoS ratio to each state's penetration rate, and then multiplying the resulting percentage impact by the state's retail electricity price. Averages across states are load-weighted.

4. Other Drivers for Changes to Retail Electricity Prices

Changes in retail electricity prices resulting from distributed solar growth—whether large or small, positive or negative—are not happening in a vacuum. A host of other factors will also influence the trajectory of retail electricity prices over time, some by potentially greater amounts, and many of these are also within the sphere of influence by utilities, state regulators, and policymakers. In this section, we review a number of these other drivers, characterize their potential impact on future electricity prices, and highlight some of the ways in which states and utilities may be able to manage their effects on retail electricity prices.

We focus on a set of drivers with relatively broad geographical applicability, namely: energy efficiency programs and policies, natural gas prices, renewables portfolio standards, state and federal carbon policies, and capital expenditures by electric utilities. Drawing on existing studies and several illustrative analyses, we describe the potential effects of each in terms of the projected impact or range of impacts on average retail electricity prices in the year 2030, highlighting regional differences where possible. In the final section of the paper, we compare these drivers directly to the potential effects of distributed solar, as discussed in the previous section.

To be clear, the analysis presented here is not comprehensive, in terms of either its depth or the breadth of issues discussed.[7] Rather, the intent is simply to provide some illustrative and approximate benchmarks against which the potential impacts of distributed solar might be gauged (and that could inform more-detailed state- or utility-specific analyses). We also reiterate that this analysis by no means considers the full set of benefits and costs that might be relevant to evaluating the issues discussed. Rather, the focus is narrowly on retail electricity price effects, as this is the particular issue motivating many of the debates related to retail rate reforms for distributed solar customers.

4.1. Energy Efficiency Programs and Policies

Net-metered solar and energy efficiency (EE) both reduce electricity sales, putting upward pressure on regulated electricity prices in the near-term, as embedded costs are recovered across a smaller base of sales (even if the resources are cost-effective over the long-run). One can thus gain some sense for the relative impact of distributed solar compared to EE, based on their relative penetration levels, while also acknowledging some important differences between the two types of resources, such as solar intermittency and relatively broad participation in energy efficiency programs.

Historically, energy efficiency policies and programs have had an inordinately greater impact on retail electricity sales than distributed solar. As noted earlier in Section 2, utility energy efficiency programs and federal appliance efficiency standards together reduced total U.S. retail electricity sales by roughly

---

[7] For example, other factors that may affect future retail electricity prices include electric vehicles, storage, and wholesale market reforms.

14% in 2015.[8] By comparison, all net-metered PV installed through the end of 2015 reduced retail electricity sales by just 0.4% (i.e., 35 times smaller than the effects of energy efficiency to-date). Even in those regions with relatively high distributed solar penetration, the effects of energy efficiency have thus far generally been far greater. For example, in San Diego Gas & Electric's service territory, annual energy savings from all efficiency programs and policies were equal to 31% of its electricity sales in 2015, compared to 5.5% penetration of distributed solar (CEC 2016).

Going forward, energy efficiency will likely continue to outpace distributed solar, though not as starkly as in the past. Energy savings from federal appliance standards and utility EE programs are projected to grow by 535 TWh over the 2015-2030 period (see Figure 11). Other efficiency policies for which projections are not available, such as state-level appliance standards and building codes, would add further to this total. By comparison, generation from distributed PV is projected to grow by 116 TWh over this timeframe (based on NREL's latest reference case). The effects of projected energy efficiency growth are thus roughly five times as great as growth in distributed PV, at the national level.
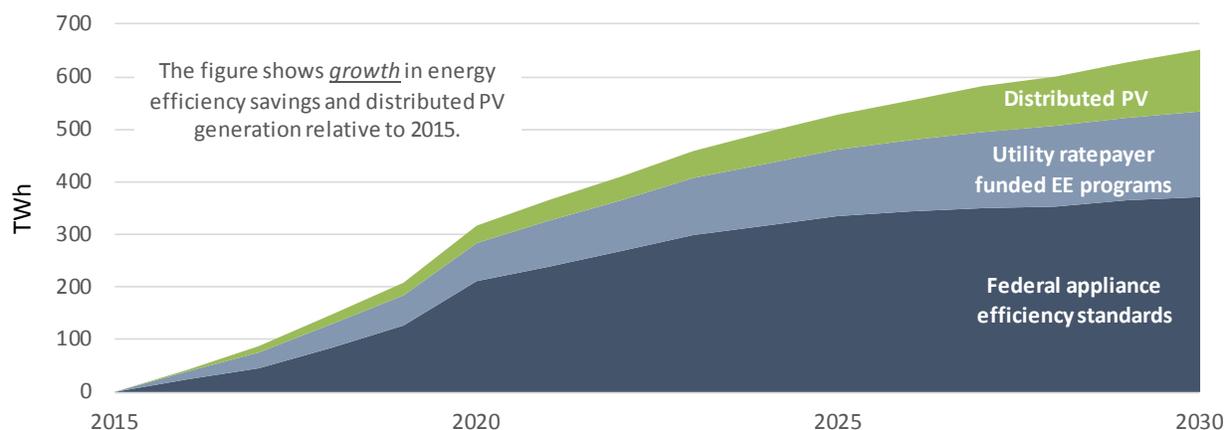
Notes: Data on federal appliance efficiency standards are adapted from Meyers et al. (2016), relying on supporting documentation provided directly by the authors. Data on utility ratepayer-funded EE programs are adapted from the mid-case projection in Barbose et al. (2013), requiring extrapolation from 2025 to 2030 and application of a decay function to accumulate savings from measures installed in successive years. Data on distributed PV are adapted from Cole et al. (2016), with generation estimated from reference-case nameplate capacity based on state-specific capacity factors. The EE projections in the figure are intended to represent savings net of free riders, but do not reflect any possible rebound effects, nor does the figure include naturally occurring EE.

Figure 11. Growth in U.S. energy efficiency savings and distributed PV generation

Assuming a value of energy efficiency savings comparable to the range considered previously for solar—equal to 50-150% of the utility's average cost of service—projected growth in energy efficiency savings through 2030 would result in roughly a ±0.8 cents/kWh change in U.S. average retail electricity prices. Of course, the value of energy efficiency could be greater or less than the value of distributed solar. For example, solar is intermittent, which would lessen its value relative to energy efficiency, but can potentially provide additional grid services that energy efficiency cannot. Solar and energy

---

[8] To be clear, this 14% represents the cumulative effect in 2015 of efficiency programs and federal standards implemented over time (as opposed to the incremental effect of just those efficiency measures implemented in 2015).

efficiency also have different hourly and seasonal profiles, which may lead to higher or lower avoided costs relative to one another. Notwithstanding these differences, it is nevertheless reasonably clear from the preceding comparison that energy efficiency is likely to have a substantially greater impact on retail electricity prices than distributed solar, at least at the national level.

Even in those states with the highest projected solar penetration levels, growth in distributed solar generation is likely to be outpaced by EE. For example, the California Energy Commission's latest demand forecast projects that statewide annual energy savings from EE programs and policies will grow by 57 TWh from 2015-2026 (CEC 2016). By comparison, the CEC projects that distributed PV will grow by 15 TWh over this period, reaching 8% penetration in 2026 and equal to roughly one-quarter the size of expected EE growth.

The purpose of this comparison is not to cast energy efficiency as a bigger "problem" than distributed solar, but rather to highlight the following two points. First and foremost, experiences with energy efficiency demonstrate that short-term rate impacts from distributed energy resources—even if at a much greater scale than would occur at projected penetration levels of distributed solar—may be acceptable provided that: (a) the resources yield net cost savings to utility ratepayers over the long run, and (b) adequate opportunities exist for all ratepayers to participate. With respect to the latter, overall participation levels in EE programs can be quite high, particularly when including appliance and building efficiency standards, and extra effort is often made to specifically target low-income customers. As the cost of solar continues to decline (making it more affordable to low- and moderate-income customers), as grid-friendly PV technologies advance (increasing the value of solar to the utility), and as initiatives to broaden solar access continue (such as community solar and other programs specifically targeting low- and moderate-income customers), issues related to the rate impacts and cost-shifting from distributed solar may become more similar to those of energy efficiency. Second, to the extent that erosion of utility sales from demand-side measures remains a concern, any regulatory response may be more effective if directed at demand-side resources more broadly, including electric vehicles and storage for example, rather than focusing in isolation on distributed solar.

4.2. Natural Gas Prices

Electricity prices have become increasingly linked with natural gas prices, as a greater share of electric power generation is fueled by gas. Nationally, natural gas-fired generation has grown from 9% of total U.S. electricity generation in 1988 to 33% in 2015, and represents more than 50% of electricity generation in many states and regions (EIA 2016b). Reliance on natural gas for electric power generation is generally expected to continue to increase over time, in part due to expectations of continued low natural gas prices.

Although gas prices are currently at historical lows, they have exhibited tremendous volatility in the past, and future prices remain highly uncertain. This is evident in Figure 12, which shows natural gas prices alternating over the past two decades between prolonged periods of lows and highs. Given that historical volatility, substantial uncertainty exists in the long-term trajectory of natural gas prices. As an

illustration of that uncertainty, Figure 12 shows confidence intervals for natural gas futures prices going forward, derived by Bolinger (2016). These confidence intervals diverge over time and have a distinct upward skew, though are far narrower than historical price variability. At the upper-bound (P90) confidence interval, 2030 gas prices are roughly $1.9/MMBtu higher than the "expected" trajectory extrapolated from the NYMEX futures strip. Utilities and regulators have some ability to limit ratepayers' exposure to this price uncertainty, chiefly by diversifying fuel sources used for electricity generation, along with limited gas price hedging.[9]

Notes: *Historical Prices are the monthly average price of NYMEX Henry Hub futures contracts for delivery in the following month, converted to real dollars based on quarterly GDP deflators (BEA 2016). Confidence Intervals for NYMEX futures prices were derived by Bolinger (2016), based on historical volatility in returns on natural gas futures contracts and NYMEX futures prices as of Sept. 19, 2016. The confidence intervals shown here represent the 10th and 90th percentile values (P10 and P90).*

Figure 12. Historical natural gas prices and confidence intervals for future prices

The manner in which gas prices affect retail electricity prices depends on the structure of the electric power industry in the particular state or region. Where retail prices are based on cost-of-service, fuel costs are often a direct pass-through.[10] In this case, the effect of gas prices on retail electricity prices should be more-or-less proportional to the price of gas and the percentage of load served by gas-fired generation. Take, for example, a utility that meets one-third of its annual energy demand with natural gas-fired generation (roughly the national average). At current gas prices, natural gas fuel supply costs would represent approximately 0.7 cents/kWh of the total retail price of electricity for that utility.[11] Naturally, this amount would be larger if gas prices were to rise or reliance on gas-fired generation were to increase, both of which are generally expected to occur.

---

[9] Financial hedges against gas price risk are limited to relatively short time horizons, as gas futures contracts generally are not liquid beyond several years, and long-term fixed-price gas supply contracts are relatively uncommon (Bolinger 2013).

[10] Although the specifics can vary from state to state, fuel and power purchase costs are often recovered through designated cost trackers, line-item charges that are updated regularly outside of rate cases. In the case of power purchased from gas-fired generators, the price of delivered power is typically indexed to prevailing gas prices, and thus gas-price risk is passed through to the utility and its ratepayers.

[11] This estimate is based on a natural gas price of $2.84/MMBu and the U.S. average heat rate of 7244 Btu/kWh for natural gas fired generation, both derived from monthly data for natural gas deliveries to the electric power sector for the twelve-month period ending May 2016 (EIA 2016b, EIA 2016c, EIA 2016d).

In restructured states where retail load is served primarily by power purchased through centralized wholesale markets, natural gas prices can have an outsized impact on electricity prices by virtue of being the "marginal" resource in a disproportionately large percentage of hours.[12] During times that gas is on the margin, it sets the market-clearing price, and all power purchased through the wholesale market, regardless of underlying fuel source, is priced at a level reflective of prevailing gas prices. In states with retail choice, retail suppliers typically procure energy on a relatively short-term basis, and therefore changes to gas commodity prices and the resulting effects on wholesale electricity prices are passed through to retail customers, if not immediately, once any short-term generation supply contracts expire and are renewed.

Natural Gas Price Scenarios and Corresponding Range in U.S. Average Retail Electricity Prices
Electricity and Gas Price Ranges are underlined relative to each study's reference case scenario for 2030
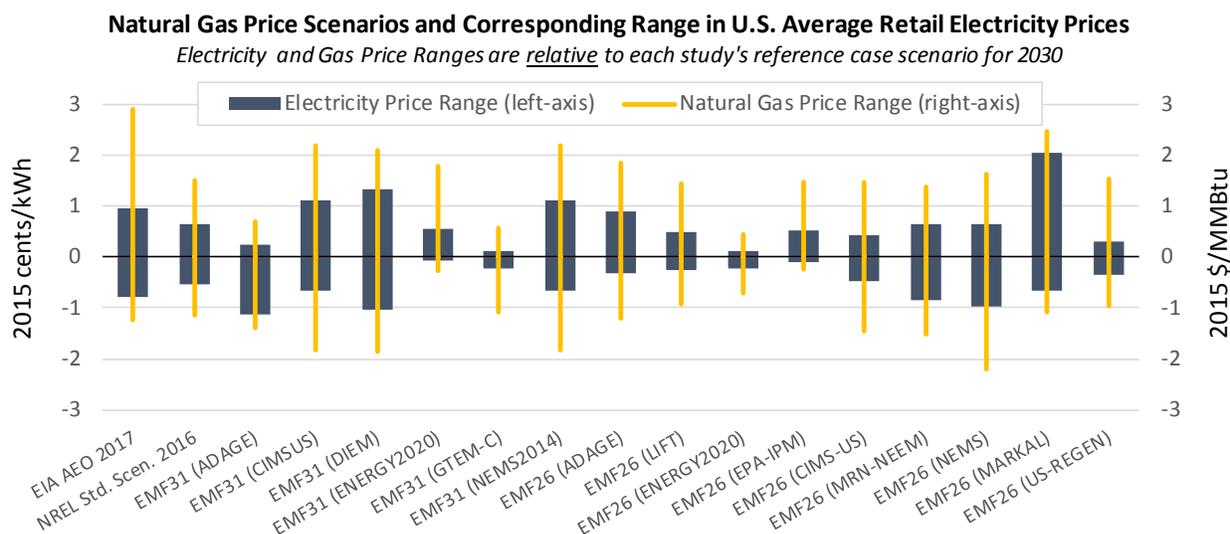
Notes: The ranges for EIA AEO 2017 are based on the low and high oil and gas resource and technology side cases (EIA 2017). The ranges for the NREL Standard Scenarios study are based on the low fuel price and high fuel price scenarios (Cole et al. 2016). The EMF31 studies are from the Stanford Energy Modeling Forum's project "EMF 31: North American Natural Gas Markets in Transition," which consists of a common set of scenarios explored by different modeling teams, using the models identified in parentheses (Stanford University 2016). The ranges shown are from low and high shale resource scenarios. The EMF26 studies are based on an earlier set of analyses by Energy Modeling Forum participants (Stanford University 2013), and the ranges shown are again from a set of low and high shale resource scenarios. For further details on scenario assumptions and modeling details, please refer to the source documents. All gas prices shown represent Henry Hub.

Figure 13. Retail electricity prices across natural gas price scenarios: Comparison of electricity market studies

To illustrate how natural gas prices—and uncertainty therein—could affect future retail electricity prices, Figure 13 compares retail electricity price projections from a broad set of recent long-term electricity market studies. These studies relied on different electricity market models to simulate future retail electricity prices under alternate assumptions about future natural gas prices. Although the specific scenario assumptions and definitions varied across the studies, most considered low and high gas price scenarios spanning a range of at least $3/MMBtu. Collectively, the results across these studies suggest that U.S. average retail electricity prices in 2030 would increase by roughly 0.4 cents/kWh, on average, with each $1/MMBtu increase in the price of natural gas. Given this average implicit

---

[12] As one example, Rose (2007) examined market clearing prices in the PJM market in 2006. Although natural gas represented just 5.5% of total electricity generation over the year, it was the marginal resource in 15% to 40% of all hours each month.

"sensitivity" span a range of 1.3 cent/kWh between the 10th and 90th percentile gas price trajectories shown in Figure 12. Under the upper confidence interval trajectory, U.S. average retail electricity prices are 0.8 cents/kWh higher than under a gas-price trajectory that tracks the current NYMEX futures strip.

As to be expected, the sensitivity of retail electricity prices to natural gas prices may be more or less pronounced at the state or regional level. This is evident in Figure 14, which shows the range in average retail electricity prices across high and low gas-price scenarios, for each of EIA's Electricity Market Module (EMM) regions. Also shown is the implied sensitivity of retail electricity prices in each region to changes in gas prices. These sensitivity levels are particularly high for the NPPC regions (New England and New York), Reliability First/East (Pennsylvania, New Jersey, Maryland), and Texas—all of which have a relatively high proportion of gas-fired generation, organized wholesale power markets, and retail choice. For those regions, EIA's modeling suggests that average retail electricity prices would increase by 0.8-1.2 cents/kWh with a $1/MMBtu increase in the price of natural gas. At that level of sensitivity, retail electricity prices would be 1.5-2.2 cents/kWh higher under the P90 gas-price projection for 2030. In contrast, other regions that either have lesser reliance on gas-fired generation or have retained cost-of-service based retail pricing exhibit considerably less sensitivity to changes in natural gas prices and would see correspondingly smaller effects on retail electricity prices across potential gas-price trajectories.

Range in Regional Average Retail Electricity Prices across Low and High Gas-Price Scenarios
Based on EIA Annual Energy Outlook 2017 projections for 2030
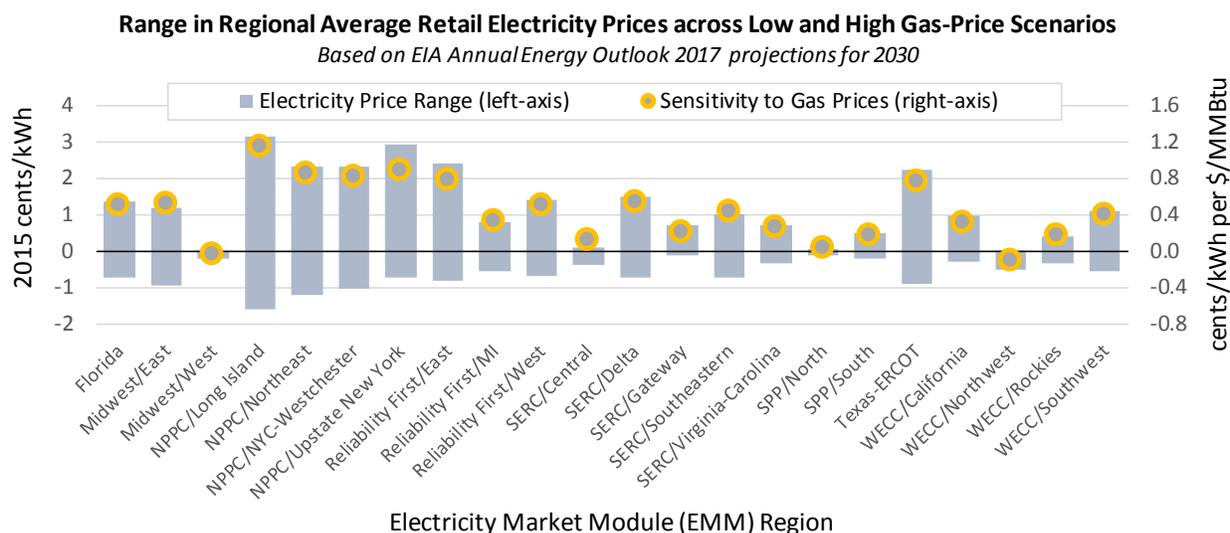
Notes: Data are based on the low and high "oil and gas resource and technology" side cases. Upper and lower bounds of electricity price ranges are relative to reference case scenario. Sensitivity to Gas Prices refers to the ratio of the range in electricity prices, between the low and high cases, to the corresponding range in Henry Hub natural gas prices. For a map identifying EIA's EMM regions: https://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf

Figure 14. Regional differences in the sensitivity of retail electricity prices to natural gas prices

4.3. Renewables Portfolio Standards

State renewables portfolio standard (RPS) requirements currently exist in 29 states plus the District of Columbia (Barbose 2016). These requirements are scheduled to ramp up over time, with most states reaching their terminal RPS percentage target by 2020 or 2025—though several states have recently

extended their RPS to 2030 or beyond. Many of these policies also include carve-outs for solar or DG.

Given that renewables historically have been, and in some circumstances continue to be, higher-cost than conventional power, issues related to electric ratepayer impacts remain a focal point in the design and administration of RPS policies. Several econometric studies estimate that, historically, RPS policies have led to anywhere from a 3-7% (or roughly 0.3-0.7 cents/kWh) increase in average retail electricity prices in RPS states (Morey and Kirsch 2013, Tra 2016, Wang 2014). Bottom-up analyses of compliance cost data submitted to state public utility commissions have generally found smaller effects, with RPS compliance costs in 2014 equivalent to roughly 1% of retail electricity bills or 0.1 cents/kWh in RPS states, on average (Barbose 2016). Reported compliance costs vary considerably across states, however, from a slight negative cost (i.e., cost savings) to upwards of 6% of retail electricity bills. Those cross-state variations reflect differences in RPS target levels, resource mix, industry structure, renewable energy certificate (REC) prices, wholesale electricity prices, reliance on pre-existing resources, and cost calculation methods.

As RPS requirements ramp up over time, the effects on retail electricity prices could potentially become more pronounced. A recent electric sector modeling study, Mai et al. (2016), estimated that incremental renewable energy growth used to meet rising RPS targets over the 2015-2030 period would lead to between a 0.1 cent/kWh decrease and a 0.1 cent/kWh increase in U.S. average electricity prices in 2030. That range reflects varying assumptions about future renewable energy technology costs and natural gas prices. For regions with relatively aggressive RPS policies, the range in potential electricity price effects is wider. For example, the study estimated between a 0.4 cent/kWh decrease and a 0.7 cent/kWh increase in average electricity prices in 2030 for the Pacific census region, and up to a 1.0 cent/kWh increase for the Northeast region. To be sure, these estimates reflect incremental RPS growth, and thus are additive to the effects of existing RPS resources, and are averaged across states with varying RPS targets.

To provide an illustrative and approximate range of the potential effect of RPS policies on future retail electricity prices at the individual state-level, we developed a simplified set of upper and lower bound assumptions to estimate the net cost of RPS compliance in each RPS state, for the year 2030. Those assumptions – which are described more fully and with supporting citations in Appendix B – differentiate between states where RPS compliance is achieved primarily through unbundled RECs and those where compliance occurs primarily through bundled power purchase agreements (PPAs) for renewable electricity. For the former group of states, the key assumptions relate to the price of RECs, where the upper bound estimates assume REC prices equal to each state's alternative compliance payment (ACP) rates; this is effectively the theoretical upper bound and represents a relatively extreme scenario in which RPS states face sustained REC shortages, in many cases well beyond their terminal RPS target year. For states relying instead on bundled PPAs for RPS compliance, the upper bound cost assumptions are effectively an extrapolation of historical compliance data. Upper bound estimates for all states also include additional costs for transmission and integration.

Based on this simplified analysis, RPS policies would result in between a 0.3 cent/kWh decrease and a 1.4 cent/kWh increase (the dashed lines in Figure 15) in the average retail price of electricity among RPS states in 2030. For some states, the ranges are considerably wider, particularly at the upper bound, which reaches as high as 3-4 cents/kWh in some cases. States with particularly high upper-bound estimates tend to be those with relatively high RPS target levels in 2030, large solar or DG carve-outs, and/or high ACP rates. More-sophisticated analyses could, of course, account for other important factors, and might suggest either wider or narrower ranges for some states.[13] One such factor is the existence of administrative cost caps in a number of states, also shown in Figure 15. As shown, those caps are typically well below the upper bound of the ranges estimated here, though utilities and regulators often have some discretion in interpretation and enforcement of these caps. If one were to assume that these administrative cost caps represent hard limits, the upper bound across all states would average 1.1 cents/kWh.

Whether RPS costs and retail price effects are ultimately nearer to the upper or lower end of the ranges in Figure 15 will depend on factors that are, at least partially, within the control of utilities, state agencies, and policymakers. In particular, REC prices and, to a lesser extent, renewables PPA prices are a function of the balance between regional supply and demand for RPS-eligible renewable electricity. State regulators and policymakers have potentially significant sway in helping to facilitate adequate supplies, for example, by establishing broad geographic eligibility for RPS resources, developing long-term contracting programs, and undertaking efforts to ease siting and transmission expansion. States can also manage RPS compliance costs and limit the effects on retail electricity prices through rules related to ACP rates (and other cost containment policies) and the disposition of ACP revenues, as in New Jersey, where these revenues are refunded to ratepayers.
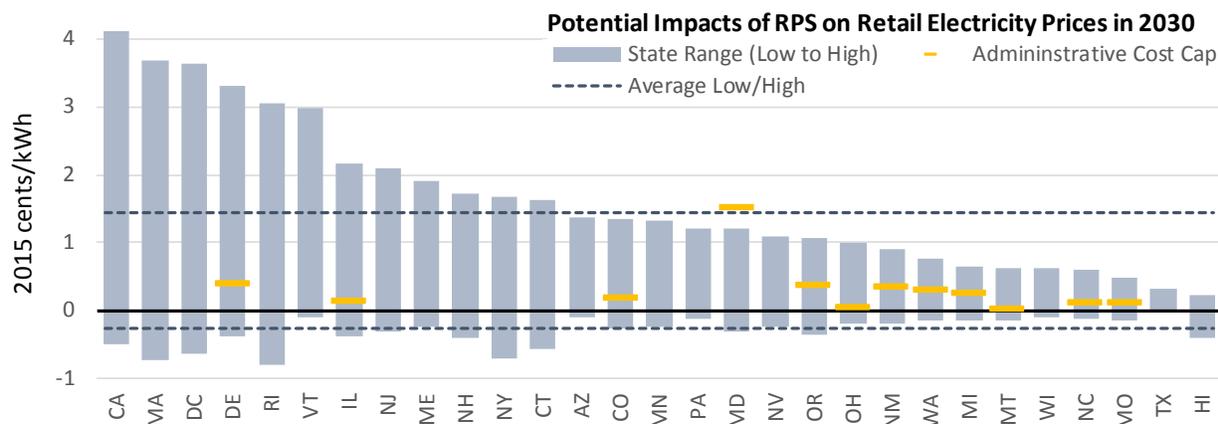
Notes: The ranges are based on a simplified set of assumptions and should be considered <u>illustrative only</u>. Averages are load-weighted. Administrative cost caps are often specified by statute in percentage terms, in which case they are translated here into units of cents/kWh based on projected retail electricity prices in 2030.

Figure 15. Illustrative range in the potential impacts of RPS requirements on retail electricity prices

---

[13] For example, the evaluation of California's 50% RPS estimated a 0.8-7.2 cents/kWh increase (real 2015$) in retail electricity prices in 2030, relative to what would occur under a continuation of the prior 33% target (E3 2014a).

4.4. State and Federal Carbon Policies

Various states, as well as the federal government, have adopted or proposed policies and regulations to limit carbon dioxide emissions in the electric sector. This includes two regional cap-and-trade programs: The Regional Greenhouse Gas Initiative (RGGI), active since 2009 and currently covering nine states in the northeast and mid-Atlantic; and California's program, launched in 2013 and linked to the Canadian province of Quebec. In addition, a number of states (California, Oregon, and Washington) have adopted emissions performance standards for new power plants, effectively prohibiting utilities from procuring new coal-fired generation and/or requiring that they phase-out coal-fired generation from their generation mix. Alongside the myriad state-level policies are several policies at the federal level, including the EPA's Clean Power Plan (CPP)—currently under stay and facing an uncertain future—as well as a separate set of emissions standards applicable to new power plants. Recognizing these uncertain costs associated with future carbon policy, many utilities consider carbon regulatory risk within their resource planning processes (Barbose et al. 2008, Wilkerson et al. 2014).

To date, existing state and regional carbon policies have had limited impact on retail electricity prices, at least in the case of the two regional cap-and-trade programs. This is partly due to low allowance prices, which are attributed to complementary policies that accomplish most of the targeted emissions reductions, and to price caps in the RGGI market (Fowlie 2016).[14] In addition, California and many RGGI states allocate some portion of allowance revenues to fund direct ratepayer bill credits. In California, these bill credits have thus far exceeded the costs of cap-and-trade program participation and compliance, yielding net reductions in electricity bills.[15] Going forward, emissions targets under both regional programs reach their plateaus in 2020 (though California and RGGI states have adopted longer term goals), and electric sector participants have already achieved, or nearly achieved, their final 2020 target levels (Acadia 2016a).[16] Retail price impacts are thus likely to remain limited, at least under current emissions reduction schedules.

With respect to the CPP, implications for retail electricity prices—if maintained—will depend largely on how states implement the federal standard, given the substantial flexibility afforded. The set of studies shown in Figure 16 project that the CPP would result in anywhere from a 0.0-1.5 cent/kWh increase in U.S. average prices. Ranges across and within studies reflect varying implementation assumptions. Among the most critical implementation options is whether states pursue rate-based or mass-based compliance, and if the latter, how allowances are allocated. For example, NERA (2016) estimated

---

[14] Since the inception of RGGI and California's programs, quarterly allowance auction prices have ranged from $2-8 per metric ton and $10-14/ton, respectively (CARB 2016, RGGI 2016a). RGGI emission allowance costs in 2014 translated to roughly 3% of total wholesale electricity procurement costs in New York and 4% in New England in 2014 (RGGI 2016b).

[15] In California, allowances are allocated to and then sold by the state's utilities, with most of the proceeds distributed to ratepayers through bill credits. Because utilities' allowance allocations have thus far exceeded their emissions, bill credits have been greater than compliance costs, yielding a net reduction in customers' bills. For example, the most recent filings from the state's three large investor-owned utilities estimate that refunds to ratepayers in 2017 will be $715 million for bundled customers, compared to $545.2 million in revenue requirements associated with cap-and-trade compliance. The values are based on the "Template D-4" tables in the utilities' GHG revenue requirement filings (PG&E 2016, SCE 2016, SDG&E 2016).

[16] In the case of the three California IOUs, emission allowances for 2020 are greater than their current emissions (CARB 2015).

roughly a 0.7 cent/kWh difference, depending on whether allowances are allocated entirely to generators or to local distribution companies (and credited to ratepayers). The scope of allowance trading may also be important; CSIS-Rhodium (2014) estimated a difference of 0.8 cents/kWh depending on whether trading occurs nationally or is confined to individual electricity market regions. Studies also show varying price impacts depending on the use of energy efficiency, which may raise retail prices while reducing average bills.

Such implementation decisions may have greater or lesser significance across individual states or regions, as illustrated in Figure 17, which compares regional retail price impacts from EIA's *Annual Energy Outlook 2016* (EIA 2016a). The greatest and most uncertain impacts are generally projected to occur in regions with either a relatively carbon-intensive generation mix or competitive markets. In carbon-intensive regions (e.g., the "Reliability First/West" region, covering much of Indiana, Ohio, and West Virginia), the effects on retail electricity prices are potentially higher simply because of the greater emission reductions required. In competitive markets (e.g., the NPPC regions, covering New England and New York), marginal-cost based pricing amplifies the effects of allowance prices and natural gas prices, which tend to be higher under the CPP as a result of coal-to-gas switching. In addition, decisions about whether to allocate allowances to distribution companies or generation owners has greater significance in competitive markets, where distribution companies do not own generation—in contrast to vertically integrated markets, where generation and distribution companies are one-and-the-same.

Increase in U.S. average retail electricity price relative to no-CPP scenario

Increase in regional average retail electricity price relative to no-CPP scenario
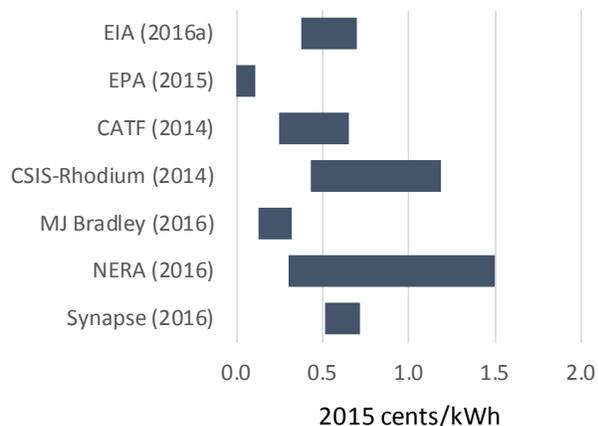
Notes: Ranges represent price impacts across multiple CPP scenarios, typically for the year 2030, though some studies only report impacts for other years or the average impact over a period of years. Differences across studies partly reflect varying vintages and thus whether they evaluated the proposed or final CPP rule, whether they included the renewable energy tax credit extenders passed in 2015, and underlying assumptions about future natural gas prices.

Notes: Data are from EIA's 2016 Annual Energy Outlook (EIA 2016a). The ranges for each Electricity Market Module region are calculated by comparing prices between each CPP scenario and the "Reference case without Clean Power Plan" scenario, for the year 2030. For a map identifying EIA's Electricity Market Module regions, see: https://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf

Figure 16. Projected impact of CPP on retail electricity prices: Comparison of electricity market studies

Figure 17. Regional differences in EIA's estimates of the CPP's impact on retail electricity prices

Beyond any uncertainties associated with CPP implementation options is a potentially much greater

uncertainty related to the possibility of more-stringent carbon policies in the future, adopted at either the state or federal levels. The CPP, if implemented, is projected to reduce U.S. electric sector emissions to 15% below 1990 levels by 2030 (EIA 2016a). By comparison, total economy-wide greenhouse gas emissions may need to decline to 80% below 1990 levels by 2050, in order to limit anthropogenic warming to less than 2 degrees Celsius (IPCC 2014). Substantially more-stringent policies may therefore be enacted over the coming decade or beyond. California, for example, recently enacted legislation requiring statewide reductions in greenhouse gases to 40% below 1990 levels by 2030, and most RGGI states have adopted comparable goals as well (Acadia 2016b).

More-stringent carbon policies could put further upward pressure on retail electricity prices. As an illustration, Figure 18 summarizes a number of electricity market studies that analyze future federal carbon policy or emission reduction scenarios roughly consistent with a trajectory reaching an 80% reduction below 1990 levels by 2050. Among this set of studies, which vary considerably in their scenario designs and modeling assumptions, U.S. average retail electricity prices would increase by 0.6-4.5 cents/kWh in 2030 and by 0.7-7.5 cents/kWh in 2050, relative to each study's baseline "no policy" scenario. State regulators and policymakers have leverage to limit the size of these effects, both through the design and implementation of future carbon policies, as well as by managing ratepayers' exposure to carbon regulatory risk (Barbose et al. 2008, Wilkerson et al. 2014). Many utilities, for example, seek to manage those risks by including CO_2 prices within their integrated resource planning (IRP) processes, with Luckow et al. (2016) reporting that 66 out of 115 utility IRPs issued over the 2012-2015 period included a CO_2 prices.
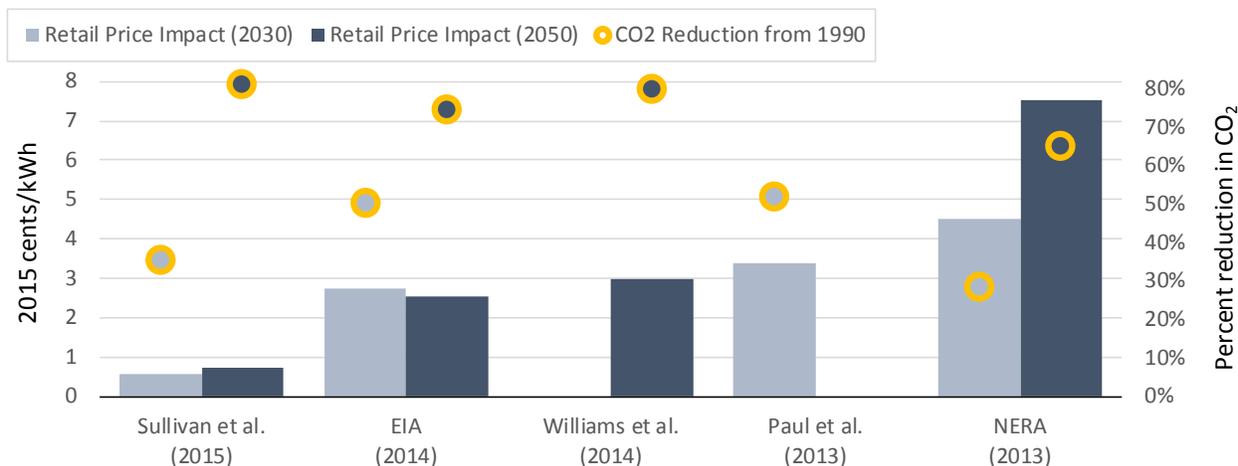
Notes: Each of the studies modeled scenarios with carbon dioxide emission taxes or targets that become progressively more stringent until 2040 (EIA 2014) or 2050 (all others). Retail price impacts represent the difference between U.S. average retail prices in the policy case and the study's baseline "no-policy" case. For Williams et al. (2014) and NERA (2013), the percentage emissions reductions shown are economy-wide; for the other studies, they are for the electric power sector, specifically. Not all studies reported results for the years 2030 and 2050. For EIA (2014), projections for the year 2040 are plotted in lieu of 2050 values. For Paul et al. (2013), 2035 values are plotted in lieu of 2030. And for NERA (2013), 2033 and 2053 values are plotted in lieu of 2030 and 2050, respectively.

Figure 18. Projected impact of potential long-term carbon policies on retail electricity prices: Comparison of electricity market studies

4.5. Electric Industry Capital Expenditures

Capital investments made under cost-of-service based regulation—which includes most T&D, as well as generation owned by regulated utilities—provide the basis for utility shareholder earnings, but put upward pressure on electricity prices.[17] These expenditures are passed-through to electricity prices via periodic rate cases, in which depreciation and financing costs associated with new capital investments are added to the utility's annual revenue requirements (and may be offset, to some extent, as pre-existing assets become fully depreciated and roll off the utility rate-base). Historically, incremental investments in the power system have been paid for by sales growth, allowing electricity prices to remain relatively stable. Going forward, however, slowing sales growth may amplify the effects of CapEx on retail electricity prices and prompt greater scrutiny by regulators when assessing the prudence of utility investments.
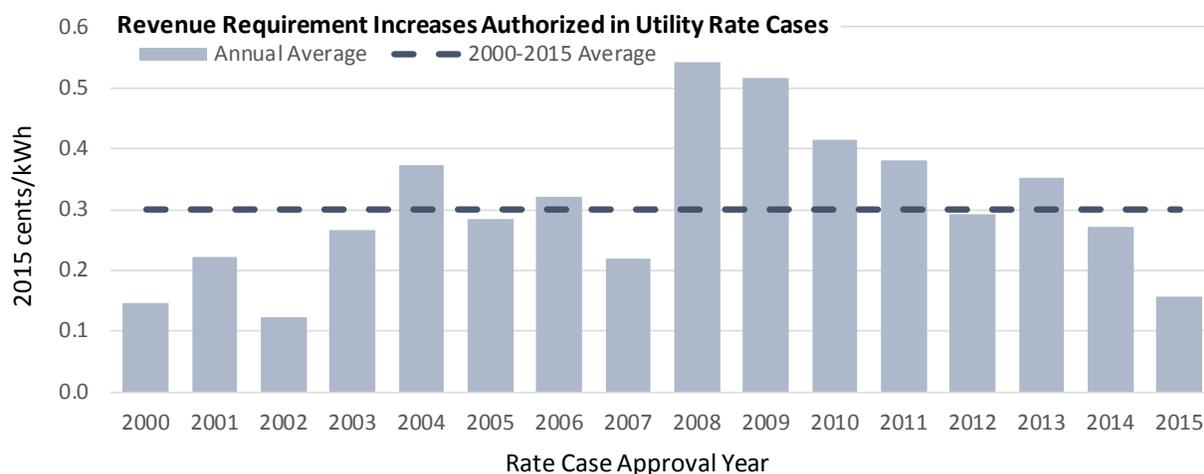
Notes: The figure is based on data from general rate cases for vertically integrated utilities (SNL Energy, April 2016). Revenue requirement increases are translated into units of cents/kWh by dividing the authorized dollar increase by each utility's retail electricity sales. Annual averages across rate cases in each year are weighted based on each utility's electricity sales.

Figure 19. Utility revenue requirement increases authorized in general rate cases

Capital expenditures (CapEx) in the electric industry have been on the rise, increasing by roughly 6% per year in real terms (8% nominal) since 2000, despite relatively flat load growth.[18] Total CapEx over that period is split roughly 40%/20%/40% among generation, transmission, and distribution system infrastructure, with T&D representing an even greater share of incremental growth in annual CapEx. As shown in Figure 19, revenue requirement increases authorized in utility rate cases have averaged 0.3

---

[17] In competitive markets, where generation capital investment costs are recovered through wholesale market prices, new generation capacity tends to put downward pressure on prices in the short-term. In the long-run, however, wholesale prices (including in any capacity markets) must be high enough to support profitable new entry in order for investment to occur (Stoft 2002).

[18] To estimate industry-wide CapEx, annual T&D-related CapEx data for IOUs (EEI 2015) was extrapolated to non-IOUs based on retail electricity sales. For generation-related investments, annual CapEx was estimated from annual capacity additions and capacity costs by fuel type (Bolinger and Seel 2016, EIA 2016h, EIA 2016i, Wiser and Bolinger 2016).

cents/kWh since 2000 (though have trended higher over the latter half of that period).[19] Assuming utilities file new rate cases every three years or so, this equates to an increase in revenue requirements of 0.1 cents/kWh annually. These data provide a rough indication for how regulated capital investments have impacted retail electricity prices historically, reflecting the net change in revenue requirements associated with new CapEx investments and pre-existing assets that became fully depreciated.

Going forward, many expect future CapEx investments in the electric industry to continue at a robust pace, driven by demands related to grid modernization, renewables growth and integration, retiring coal-fired generation, aging T&D infrastructure, security and weather risks, and load growth—even if relatively modest in many regions (ASCE 2013, Deloitte 2016, EEI 2016b, Ernst & Young 2014, Pfeifenberger et al. 2015). These sources of CapEx growth overlap to some extent with drivers discussed in previous sections, though also encompass a broader set of trends.

The impact of future CapEx on retail electricity prices will depend on both the level of investment as well as the cost of capital, which is currently quite low by historical standards. To illustrate, we consider two plausible (though perhaps not especially extreme) scenarios, as outlined in Table 3. In the low case, annual CapEx investment remains flat at current levels. This trajectory, which is based on analysis by the American Society of Civil Engineers, is intended to reflect the minimum pace of investment necessary to maintain acceptable reliability, but without any major transformation of the industry. At the high end, we assume annual CapEx continues to grow at the same rate as over the 2000-2015 period. The weighted-average cost of capital in the two cases reflect the historical range for regulated electric utilities since 2000. In estimating the corresponding effects on retail electricity prices, we focus on just the portion of CapEx investments assumed to be made by regulated entities.

Table 3. Estimated impact of future capital expenditures on retail electricity prices

	Low	High
Annual CapEx through 2030 ($2015)	$100 billion/yr (constant)	6% real annual growth, from $100 billion in 2015
Weighted-average cost of capital (WACC)	6%	9%
Impact on average retail electricity prices in 2030 ($2015)	1.6 cents/kWh	3.6 cents/kWh

Notes: The low case CapEx trajectory is based on ASCE (2016), which estimates total electric industry infrastructure investments needed through 2040 in order to meet load growth. The CapEx growth rate in the high case is equal to average annual growth from 2000-2015, where annual CapEx is calculated in the manner described in footnote 18. In both cases, we assume that 75% of future CapEx investments are made by regulated entities (based on a 50/50 split between generation and T&D, and the assumption that half of generation investments and effectively all T&D investments are made by regulated entities). The low and high WACC assumptions are based on the minimum and maximum annual industry averages over the 2000-2015 period, calculated from data published by Damodaran (2016) and S&P Global Market Intelligence (2016). Both scenarios assume an average 30-year depreciation life for new CapEx investments, and use forecasted U.S. retail electricity sales from the EIA's 2016 Annual Energy Outlook reference case to translate dollar costs into cents/kWh (EIA 2016a).

---

[19] These revenue requirement increases are expressed in units of cents/kWh in order to show how they translate into a retail price impact. However, these values do not represent authorized rate increases, per se. The net change in average electricity rates depends on how growth in revenue requirements compares to growth in electricity sales.

Across this set of scenarios, we estimate that the revenue requirements associated with future CapEx by regulated electric utilities equate to a 1.6-3.6 cent/kWh increase in U.S. average retail electricity prices in 2030. For some utilities—for example, those making investments in new nuclear generation capacity or undertaking major grid modernization initiatives—the potential impacts on retail prices may be greater than the range estimated above or may occur over a more-accelerated timeframe. To be sure, the above range does not consider reductions in revenue requirements that will naturally occur as pre-existing assets become fully depreciated over time. The purpose of this estimate, however, is to illustrate the potential significance of regulators' ongoing efforts to ensure and incentivize the prudence of future CapEx investments.

5. Summary and Conclusions

Concerns about the potential impacts of net-metered PV on retail electricity prices have led to an array of proposals to reform rate structures and net metering rules for solar customers. These proposals have typically been met with a great deal of contention and often absorb substantial time and administrative resources, potentially at the expense of other issues that may ultimately have greater impact on utility ratepayers. Given those tradeoffs, this paper seeks to help regulators, utilities, and other stakeholders gauge how much attention to devote to evaluating and addressing the possible effects of distributed solar on retail electricity prices.

Drawing on a combination of back-of-the-envelope style analyses and literature review, we characterize the potential effects of distributed solar on retail electricity prices, at both current and projected future penetration levels, and compare these estimates to a number of other important drivers for future retail electricity prices. Figure 20 provides a high-level comparison, based on indicative ranges for the potential retail price effects of distributed solar and each of the other issues analyzed.
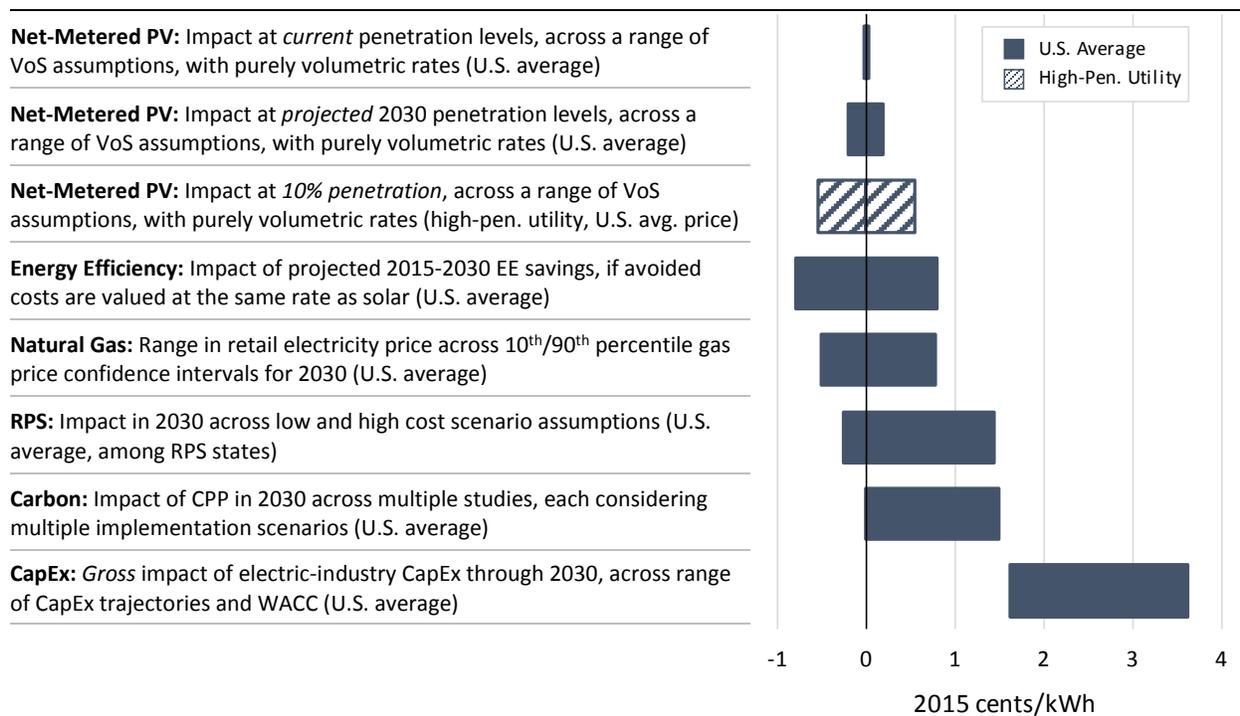
Notes: Current net-metered PV penetration equal to 0.4% of total U.S. retail electricity sales, as of year-end 2015. Projected 2030 net-metered PV penetration is 3.4%, based on Cole et al. (2016). VoS assumptions range from 50% to 150% of average cost-of-service. Please refer to the main body of the report for further details on how the ranges shown here were derived.

Figure 20. Indicative ranges for potential effects on average retail electricity prices

These ranges, which are based on data and analysis presented in earlier sections of the report, are intended to provide a *rough* sense for the relative magnitude of each of these drivers. This illustrative comparison certainly should not be considered a substitute for state- or utility-specific analysis. Indeed,

as discussed within the main body of this paper, regional and other factors may lead to effects that fall well outside the ranges shown here. It is also important to reiterate that this paper focuses narrowly on the question of retail price effects, as this is the particular issue motivating much of the discussion surrounding retail rate reforms for distributed solar. It is not a cost-benefit analysis, and certainly does not address the full set of issues relevant to evaluating the particular resources and policies discussed.

With these considerations in mind, we offer the following summary points:

- **For the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future.** At current penetration levels (0.4% of total U.S. retail electricity sales), distributed solar likely entails no more than a 0.03 cent/kWh long-run increase in U.S. average retail electricity prices, and far smaller than that for most utilities. Even at projected penetration levels in 2030, distributed solar would likely yield no more than roughly a 0.2 cent/kWh (in 2015$) increase in U.S. average retail electricity prices, and less than a 0.1 cent/kWh increase in most states, where distributed solar penetration is projected to remain below 1% of electricity sales. These estimates assume a relatively low VoS equal to just 50% of the average utility CoS, and relatively generous solar compensation levels based on full NEM with volumetric pricing.

- **For states or utilities with particularly high distributed solar penetration levels, retail electricity price effects may be more significant, but depend critically on the value of solar and underlying rate structure.** Four utilities, all in Hawaii, currently have solar penetration rates on the order of 10% of electricity sales, and three other states are projected to reach this mark by 2030. Assuming a utility value of solar ranging from 50% to 150% of its average cost of service, this level of distributed solar would yield a maximum 5% increase in retail electricity prices (e.g., 0.5 cents/kWh for a utility with electricity prices otherwise equal to the national average), under net metering with purely volumetric rates. Under rate structures with fixed charges or demand charges—as are already common, particularly for commercial customers—the effects would be shifted downward.

- **Energy efficiency has had, and is likely to continue to have, a far greater impact on electricity sales than distributed solar.** Distributed solar and energy efficiency can both impact retail electricity prices by virtue of reducing electricity sales. Utility energy efficiency programs and federal appliance efficiency standards together reduced U.S. retail electricity sales in 2015 by an amount 35-times larger than that of distributed solar. Projected growth in energy efficiency savings from those policies through 2030 is almost 5-times greater than projected growth in distributed solar generation. Assuming, for the sake of simple comparison, that the value of energy efficiency savings to the utility is based on the same VoS range as above (50-150% of the utility CoS), growth in energy efficiency savings over the 2015-2030 period would result in up to a ±0.8 cent/kWh change in U.S. average retail electricity prices.

- **Natural gas prices impose substantial uncertainty on future electricity prices.** Electricity prices have become increasingly linked with gas prices, and are likely to become more so with continued

growth in the share of electricity generated from gas. Although current gas prices are near historical lows, future prices remain highly uncertain, and that uncertainty is skewed upward. Gas-price confidence intervals developed Bolinger (2017) suggest a 10% probability that gas prices in 2030 will be at least $1.9/MMBtu higher than expected (based on the current NYMEX gas futures strip). Based on a broad set of electricity market modeling studies, an increase in gas prices of this magnitude would lead to roughly a 0.8 cent/kWh increase in U.S. average retail electricity prices. Restructured regions, which have more acute sensitivity to natural gas prices, could see retail electricity price increases of more than twice that amount.

- **Though their historical effects on retail electricity prices appear small, state RPS programs could lead to greater impacts if supply does not keep pace with demand.** RPS compliance cost data suggest that the policies have thus far increased retail electricity prices by just 0.1 cents/kWh, on average, in RPS states. Rising targets over the coming years may put upward pressure on costs, which could be amplified if supplies of eligible renewable energy don't keep pace. At the extreme (and arguably rather implausible) upper end—which assumes that REC prices in all markets are trading at their caps and that other administrative cost caps are not enforced—we estimate that retail electricity prices in RPS states could increase by 1.4 cents/kWh in 2030, on average, and by 3-4 cents/kWh in some states. Smaller retail price effects are expected in practice, and even decreases in average prices are possible, depending in part on how barriers to renewables development are addressed.

- **The effects of state and federal carbon policies on future retail electricity prices are highly dependent on program design and implementation details.** Existing cap-and-trade programs in California and the Northeast have had limited impacts on retail electricity prices to-date. In large part, this is because complementary policies have accomplished much of the targeted emission reductions, and because auction proceeds are used for ratepayer bill credits. Studies of the CPP—currently under stay and facing an uncertain future—have estimated that it could result in anywhere from 0.0-1.5 cent/kWh increase in U.S. average retail electricity prices. Much of that range reflects differences in assumptions about how states implement the federal standard, such as whether states pursue rate-based or mass-based compliance, how allowances are allocated, the scope of allowance trading, and the degree of reliance on energy efficiency. Over the long-term, additional or more-stringent carbon policies at the state or federal levels are also possible and could yield a wider range of potential effects on retail electricity prices.

- **Future capital expenditures in the electricity industry will put upward pressure on retail electricity prices.** Capital expenditures (CapEx) in the electric industry have been on the rise, increasing by roughly 6% per year in real terms (8% nominal) since 2000, despite relatively flat load growth. Going forward, the impacts of continued utility CapEx on retail electricity prices will depend on both the pace of future investments as well as utilities' cost of capital. Considering a plausible range of assumptions for those two factors, we estimate a 1.6-3.6 cent/kWh impact on U.S. average retail electricity prices in 2030, as a result of future CapEx by regulated utilities (some portion of which will be offset as existing CapEx investments become fully depreciated). For some utilities—

for example, those making investments in new nuclear generation capacity or undertaking major grid modernization initiatives—the potential impacts on retail prices may be greater than the range estimated above or may occur over a more-accelerated timeframe.

The most basic conclusion of this paper is that, in most cases, the effects of distributed solar on retail electricity prices are, and will continue to be, quite small compared to many other issues. That is not to say that reforms of net metering rules or retail rate structures for distributed solar customers are unwarranted. However, other objectives, such as economic efficiency, likely provide a more compelling rationale. Reforms may thus best be tailored to meeting those objectives—for example, through rate structures that accurately signal the long-term marginal cost of producing and delivering electricity.

Where concerns about minimizing retail electricity price remain a priority, other issues may prove more impactful. Among the issues explored in this paper, future electric-utility capital expenditures are expected to have, by far, the greatest impact on the trajectory of retail electricity prices. That is not to say anything about the potential benefits or prudence of such investments, but clearly this is an area where regulatory oversight can play a crucial role in managing retail electricity price escalation. Similarly, resource planning and procurement processes provide another important point of leverage over future retail electricity prices, where utilities and regulators can manage ratepayers' exposure to natural gas price risk and the possible costs associated with state or federal carbon regulations. Regulators and policymakers in states with RPS policies also have significant influence over retail electricity prices by developing RPS rules and other supportive policies that ensure renewable electricity supply keeps pace with growing RPS demand, keeping REC prices in check.

For states and utilities with exceptionally high distributed solar penetration levels, the effects on retail electricity prices could begin to approach the same scale as other important drivers (at least among residential customers, where solar compensation is based on full net metering with predominantly volumetric rate structures). In these cases, questions about the value of solar become more important to assessing possible cost-shifting. Efforts to encourage higher value forms of deployment also offer a strategy for mitigating any cost-shifts, for example by directing development toward geographic regions with the greatest T&D deferral opportunities, by developing mechanisms to leverage the capabilities of advanced inverters, or by incentivizing the pairing of solar with storage or demand response. Such strategies represent an alternative (and potentially less contentious) approach to addressing the effects of distributed solar on retail electricity prices (Barbose et al. 2016).

Experiences with energy efficiency also offer lessons for states witnessing especially high levels of distributed solar penetration. In particular, these experiences suggest that short-term retail price impacts from distributed energy resources may be more acceptable, provided that they yield net savings to ratepayers over the long run, and that adequate opportunities exist for all ratepayers (especially low- and moderate-income customers) to participate. As solar costs continue to decline, grid-friendly PV technologies advance, and initiatives to broaden solar access continue, issues of cost-shifting from distributed solar will become more similar to those of energy efficiency. As this occurs, concerns about cost-shifting may naturally soften, to a degree.

References

ABB 2016. "Ventyx Velocity Suite database." Accessed November 11, 2016.

Acadia. 2015. *Value of Distributed Generation: Solar PV in Massachusetts*. Boston, MA: Acadia Center.

Acadia. 2016a. *Regional Greenhouse Gas Initiative Status Report Part I: Measuring Success*. Boston, MA: Acadia Center.

Acadia. 2016b. *Regional Greenhouse Gas Initiative Status Report Part II: Achieving Climate Commitments*. Boston, MA: Acadia Center.

ASCE. 2013. *Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure*. Washington, DC: American Society for Civil Engineers.

ASCE. 2016. *Failure to Act: Closing the Infrastructure Investment Gap for America's Economic Future*. Washington, DC: American Society for Civil Engineers.

Barbose, G., R. Wiser, A. Phadke, and C. Goldman. 2008. *Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-44E.

Barbose, G. 2016. *U.S. Renewables Portfolio Standards Annual Status Report*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1005057. https://emp.lbl.gov/projects/renewables-portfolio

Barbose G., J. Miller, B. Sigrin, E. Reiter, K. Cory, J. McLaren, J. Seel, A. Mills, N. Darghouth, and A. Satchwell. 2016. *On the Path to SunShot: Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65670. http://www.nrel.gov/docs/fy16osti/65670.pdf.

BEA 2016. "Table 1.1.9. Implicit Price Deflators for Gross Domestic Product," annual series for 1929-2015. Washington, DC: U.S. Bureau of Economic Analysis. http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=1&isuri=1 (accessed September 1, 2016).

Berg, W., S. Nowak, M. Kelly, S. Vaidyanathan, M. Shoemaker, A. Chittum, M. DiMascio, and C. Kallakuri. 2016. *The 2016 State Energy Efficiency Scorecard*. Washington, DC: American Council for an Energy Efficient Economy (ACEEE), Report U1606.

BNEF. 2016. *New Energy Outlook 2016.* New York, NY: Bloomberg New Energy Finance.

Bolinger, M. 2013. *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-6103E.

Bolinger, M. 2017 (forthcoming). *Using Probability of Exceedance to Compare the Resource Risk of Renewable and Gas-Fired Generation*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Bolinger M. and J. Seel. 2016. *Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL- 1006037.

Burtraw, D., M. Woerman, and A. Paul. 2012. "Retail electricity price savings from compliance flexibility in GHG standards for stationary sources." *Energy Policy* 42(2012): 67–77.

Burtraw, D. and M. Woerman. 2013. *Technology Flexibility and Stringency for Greenhouse Gas Regulations*. Washington DC: Resources for the Future. RFF DP 13-24.

Burtraw, D., J. Linn, K. Palmer, and A. Paul. 2014. "The Costs and Consequences of Clean Air Act Regulation of CO2 from Power Plants." *American Economic Review*, Papers & Proceedings 2014, 104(5): 557–562.

CARB. 2016. "California Cap-and-Trade Program Summary of Joint Auction Settlement Prices and Results." Sacramento, CA: California Air Resources Board. https://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf

CARB 2015. "Annual Allocation to Electrical Distribution Utilities (EDU) under the Cap-and-Trade Regulation." Sacramento, CA: California Air Resources Board. https://www.arb.ca.gov/cc/capandtrade/allowanceallocation/edu-ng-allowancedistribution/electricity-allocation.pdf

CATF. 2014. *Power Switch: An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants*. Boston, MA: Clean Air Task Force.

CEC. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast*. Sacramento, CA: California Energy Commission. CEC-200-2016-001-V1.

Clean Power Research. 2012. The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania. Prepared for: Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association. Napa, CA: Clean Power Research.

Clean Power Research. 2013a. *2014 Value of Solar Executive Summary*. Prepared for: Austin Energy. Napa, CA: Clean Power Research.

Clean Power Research. 2013b. *The Value of Distributed Solar Electric Generation to San Antonio*. Prepared for: Solar San Antonio. Napa, CA: Clean Power Research.

Clean Power Research. 2014. *Value of Solar in Utah*. Prepared for: Utah Clean Energy. Napa, CA: Clean Power Research.

Clean Power Research. 2015. *Maine Distributed Solar Valuation Study*. Prepared for: Maine Public Utilities Commission. Napa, CA: Clean Power Research.

Cole, W., T. Mai, J. Logan, D. Steinberg, J. McCall, J. Richards, B. Sigrin, and G. Porro. 2016. *2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-66939.

Crossborder Energy. 2013a. *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*. Prepared for: The Alliance for Solar Choice. Berkeley, CA: Crossborder Energy.

Crossborder Energy. 2013b. *Evaluating the Benefits and Costs of Net Energy Metering in California*. Prepared for: The Vote Solar Initiative. Berkeley, CA: Crossborder Energy.

Crossborder Energy. 2013c. *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*. Prepared for: The North Carolina Sustainable Energy Association. Berkeley, CA: Crossborder Energy.

Crossborder Energy. 2016. *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)*. Prepared for: The Alliance for Solar Choice. Berkeley, CA: Crossborder Energy.

CSIS-Rhodium. 2014. *Remaking American Power: Potential Energy Market Impacts of EPA's Proposed GHG Emission Performance Standards for Existing Electric Power Plants*. Washington, D.C.: Center for Strategic and International Studies and the Rhodium Group.

Damodaran, A. 2016. Archived data on "Cost of Capital by Industry". New York, NY: New York University (NYU), Stern School of Business. http://pages.stern.nyu.edu/~adamodar/

Deloitte. 2016. *From Growth to Modernization: The Changing Capital Focus of the US Utility Sector*. Houston, TX and Washington, DC: Deloitte Center for Energy Solutions.

E3. 2013. *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for: The California Public Utilities Commission. San Francisco, CA: Energy and Environmental Economics.

E3. 2014a. *Investigating a Higher Renewables Portfolio Standard in California*. Prepared for: The Public Utilities Commission. San Francisco, CA: Energy and Environmental Economics.

E3. 2014b. *Nevada Net Energy Metering Impacts Evaluation*. Prepared for: The Public Utilities Commission of Nevada. San Francisco, CA: Energy and Environmental Economics.

EEI. 2015. "Construction Expenditures for Transmission and Distribution Years 1984 through 2014." Table 9.1 of EEI's Statistical Yearbook. Washington, DC: Edison Electric Institute.

EEI. 2016a. "EEI Industry Capital Expenditures with Functional Detail." Washington, DC: Edison Electric Institute. http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Documents/EEI_Industry_Capex_Functional_2016.08.24.pptx (accessed September 30, 2016).

EEI. 2016b. "The Promise of Tomorrow: Electric Power Industry Outlook." The Edison Electric Institute's 2016 Wall Street Briefing. Washington, DC: Edison Electric Institute.

EIA. 2012. "Table 8.10 Average Retail Prices of Electricity, 1960-2011." *Annual Energy Review 2012*. Washington, DC: Energy Information Administration.

EIA. 2014. *Annual Energy Outlook 2014*. Washington, DC: Energy Information Administration.

EIA. 2015a. *Analysis of the Impacts of the Clean Power Plan*. Washington, DC: Energy Information Administration.

EIA. 2015b. *Annual Energy Outlook 2015*. Washington, DC: Energy Information Administration. http://www.eia.gov/forecasts/archive/aeo15/ (accessed September 20, 2016).

EIA. 2015c. *Electric Power Annual 2015*. Washington, DC: Energy Information Administration.

EIA. 2016a. *Annual Energy Outlook 2016*. Washington, DC: Energy Information Administration. https://www.eia.gov/forecasts/aeo/index.cfm (accessed September 20, 2016).

EIA. 2016b. *Monthly Energy Review*. Washington, DC: Energy Information Administration. http://www.eia.gov/totalenergy/data/monthly/#electricity (accessed September 20, 2016).

EIA. 2016c. "Natural Gas Consumption by End Use." Washington, DC: Energy Information Administration. http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm (accessed September 20, 2016).

EIA. 2016d. "Natural Gas Prices by End Use." Washington, DC: Energy Information Administration. Last accessed September 19, 2016. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

EIA. 2016e. "Preliminary EIA-826 Monthly Survey Data." Washington, DC: Energy Information Administration. https://www.eia.gov/electricity/data/eia826/xls/sales_revenue.xls (accessed September 20, 2016).

EIA. 2016f. "State Energy Data System (SEDS): 1960-2014." Washington, DC: Energy Information Administration. https://www.eia.gov/state/seds/seds-data-complete.cfm#Consumption (accessed September 20, 2016).

EIA. 2016g. "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files." Washington, DC: Energy Information Administration. https://www.eia.gov/electricity/data/eia861/ (accessed October 24, 2016).

EIA. 2016h. "Construction cost data for electric generators installed in 2013." Washington, DC: Energy Information Administration. http://www.eia.gov/electricity/generatorcosts/ (accessed November 8, 2016).

EIA. 2016i. *Electric Power Annual 2016*. Washington, DC: Energy Information Administration.

EIA. 2017. *Annual Energy Outlook 2017*. Washington, DC: Energy Information Administration.

EnerNex. 2010. *Eastern Wind Integration and Transmission Study*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-550-47078.

EPA (Environmental Protection Agency). 2015. Regulatory Impact Analysis for the Clean Power Plan Final Rule. Washington, D.C.

Ernst & Young. 2014. *Capital Outlook: Power and Utilities*. Brisbane, Australia: EY Global Power & Utilities Center.

Fagan, M. 2006. "Measuring and Explaining Electricity Price Changes in Restructured States." *The Electricity Journal* 19(5), 35-42.

Fagan, B., P. Luckow, D. White, and R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM*. Cambridge, MA: Synapse Energy Economics, Inc. www.synapse-energy.com/Downloads/SynapseReport.2013-05.EFC.Increased-Wind-Power-in-PJM.12-062.pdf (accessed November 17, 2015).

Faruqui, A. 2013. "Surviving Sub-One-Percent Growth." ElectricityPolicy.com white paper, June 2013. https://www.electricitypolicy.com/articles/5677-surviving-sub-one-percent-growth (accessed September 30, 2016).

Fowlie, M. 2016. "Time to Unleash the Carbon Market?" Berkeley, CA: Energy Institute at Haas. Blog

post. https://energyathaas.wordpress.com/2016/06/20/time-to-unleash-the-carbon-market/

GE Energy. 2010. *Western Wind and Solar Integration Study*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-550-47434.

GTM/SEIA. 2016. *U.S. Solar Market Insight: 2015 Year in Review*. Boston, MA: GTM Research and the Solar Energy Industries Association.

Hallock, L., and R. Sargent. 2015. *Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society*. Washington, D.C.: Environment America Research and Policy Center.

Hansen, L., V. Lacy, and D. Glick. 2013. *A Review of Solar PV Cost and Benefit Studies, 2nd edition*. Boulder, CO: Rocky Mountain Institute.

Hirsh. R. 1999. *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility System*. Cambridge, MA: MIT Press.

IHS 2016. "PV Demand Market Tracker - Q3 2016." Austin, TX: IHS Technology.

Inskeep, B., E. Case, K. Daniel, B. Lips, A. Proudlove, D. Sarkisian, A. Shrestha, K. Wright, R. Cook, C. Laurent, E. Gessesse, and W. Hanley. 2016. *The 50 States of Solar: 2015 Policy Review, Q4 Quarterly Report*. North Carolina Clean Energy Technology Center and Meister Consultants Group. https://nccleantech.ncsu.edu/wp-content/uploads/50sosQ4-FINAL.pdf

IPA. 2013. *Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts.* Chicago, IL: Illinois Power Authority. http://www.illinois.gov/ipa/Documents/201304-IPA-Renewables-Report.pdf

IPCC. 2014. "Summary for Policymakers." In: *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press.

Joskow, P. 1989. *Regulatory Failure, Regulatory Reform and Structural Change in the Electric Power Industry*. Cambridge, MA: Massachusetts Institute of Technology.

Joskow, P. 2006. "Markets for Power in the United States: An Interim Assessment," *The Energy Journal* 27 (1), 1-36.

Kahn, E. 1988. *Electric Utility Planning and Regulation*. Washington, DC: American Council for an Energy Efficient Economy (ACEEE).

Lincoln Electric System. 2014. *LES Value of Distributed Photovoltaic Solar Study*.

Luckow P., E. Stanton, S. Fields, W. Ong, B. Biewald, S. Jackson, and J. Fisher. 2016. *Spring 2016 National Carbon Dioxide Price Forecast*. Cambridge, MA: Synapse Energy Economics.

Maggio, D.J. 2012. "Impacts of Wind-Powered Generation Resource Integration on Prices in the ERCOT Nodal Market." In 2012 IEEE Power and Energy Society General Meeting, 1–4, doi:10.1109/PESGM.2012.6344611.

Mai, T., R. Wiser, G. Barbose, L. Bird, J. Heeter, D. Keyser, V. Krishnan, J. Macknick, and D. Millstein. 2016. *A Prospective Analysis of the Costs, Benefits, and Impacts of U.S. Renewable Portfolio Standards*. Golden, CO: National Renewable Energy Laboratory and Berkeley, CA: Lawrence Berkeley National Laboratory.

Mills, A., R. Wiser, and K. Porter. 2012. "The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies." *Renewable and Sustainable Energy Reviews* 16 (1); pp. 1–19.

MJ Bradley. 2016. *EPA's Clean Power Plan: Summary of IPM Modeling Results With ITC/PTC Extension*. Concord, MA: M.J. Bradley and Associates. http://www.mjbradley.com/sites/default/files/MJBA_CPP_IPM_Summary.pdf (accessed September 17, 2016).

Meyers, S., A. Williams, P. Chan, and S. Price. *Energy and Economic Impacts of U.S. Federal Energy and Water Conservation Standards Adopted From 1987 Through 2015*. Berkeley, CA: Lawrence Berkeley National Laboratory, LBNL- 1004328.

Mills, A. and R. Wiser. 2013. "Changes in the Economic Value of Photovoltaic Generation at High Penetration Levels: A Pilot Case Study of California." *IEEE Journal of Photovoltaics* 3(4), 1394-1402.

Mills, A., G. Barbose, J. Seel, C. Dong, T. Mai, B. Sigrin, and J. Zuboy. 2016. *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1006047.

Morey, M. and L. Kirsch. 2013. "Retail Rate Impacts of State and Federal Electric Utility Policies," *The Electricity Journal* 26(3), 35-49.

Morey, M. and L. Kirsch. 2016. *Retail Choice in Electricity: What Have We Learned in 20 Years?* Madison, WI: Christianson Associates Energy Consulting, LLC.

NERA. 2013. *Economic Outcomes of a U.S. Carbon Tax.* Prepared for: The National Association of Manufacturers. Boston, MA: NERA Economic Consulting.

NERA. 2016. *Potential Electricity and Energy Price Outcomes under EPA's Federal Plan Alternatives for the Clean Power Plan*. Prepared for: The American Forestry and Paper Association. Boston, MA: NERA Economic Consulting.

NREL. 2016. PVWatts Calculator. National Renewable Energy Laboratory. http://pvwatts.nrel.gov/

Perez, R., B.L. Norris, and T.E. Hoff. 2012. The Value of Solar to New Jersey and Pennsylvania. Napa, CA: Clean Power Research. http://asrc.albany.edu/people/faculty/perez/2012b/MSEIA.pdf

Paul, A., B. Beasley, and K. Palmer. 2013. *Taxing Electricity Sector Carbon Emissions at Social Cost*. Washington, DC: Resources for the Future. RFF DP 13-23-REV.

PG&E. 2016. "2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation." San Francisco, CA: Pacific Gas and Electric Company. Filed with the California Public Utilities Commission, June 1.

Pfeifenberger, J., J. Chang, and J. Tsoukalis. 2015. "Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure." JP Morgan Investor Conference, July 17.

Proudlove, A. 2016. Personal communication with staff at the North Carolina Clean Energy Technology Center. September 23, 2016.

RGGI. 2016a. "Auction Results." New York, NY: Regional Greenhouse Gas Initiative, Inc. https://www.rggi.org/market/co2_auctions/results

RGGI. 2016b. *CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2014 Monitoring Report*. New York, NY: Regional Greenhouse Gas Initiative, Inc.

Ros, A. 2015. An econometric assessment of electricity demand in the United States using panel data and the impact of retail competition on prices. Boston, MA: NERA Economic Consulting.

Rose, K. 2007. *The Impact of Fuel Costs on Electric Power Prices*. East Lansing, MI: Institute of Public Utilities (IPU) at Michigan State University.

S&P Global Market Intelligence. 2016. "Regulatory Focus." January 14, 2016. Edison, NJ: Regulatory Research Associates.

SAIC. 2013. *2013 Updated Solar PV Value Report*. Prepared for Arizona Public Service. SAIC Energy, Environment & Infrastructure, LLC.

Satchwell, A., A. Mills, G. Barbose, R. Wiser, P. Cappers, and N. Darghouth. 2014. *Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities*.

Berkeley, CA: Lawrence Berkeley National Laboratory, LBNL-6913E.

SCE. 2016. "Energy Resource Recovery Account (ERRA) 2017 Forecast of Operations." Rosemead, CA: Southern California Edison. Filed with the California Public Utilities Commission, May 2.

SDG&E. 2016. "Application of San Diego Gas & Electric Company (U 902-E) for Approval of its 2017 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts." San Diego, CA: San Diego Gas & Electric. Filed with the California Public Utilities Commission, April 15.

SolarCity/NRDC. 2016. *Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources*. San Mateo, CA: SolarCity Corporation and the Natural Resources Defense Council.

Stanford University. 2013. "EMF 26 Database." EMF 26: Changing the Game? Emissions and Market Implications of New Natural Gas Supplies. Palo Alto, CA: Stanford University. https://emf.stanford.edu/projects/emf-26-changing-game-emissions-and-market-implications-new-natural-gas-supplies-0

Stanford University. 2016. "EMF 31 Model Results". EMF 31: North American Natural Gas Markets in Transition. Palo Alto, CA: Stanford University. https://emf.stanford.edu/projects/emf-31-north-american-natural-gas-markets-transition

Stoft, S. 2002. *Power System Economics: Designing Markets for Electricity*. The Institute of Electrical and Electronics Engineers. New York, NY: John Wiley & Sons.

Su, X. 2015. "Have Customers Benefited from Electricity Retail Competition?" *Journal of Regulatory Economics* 47(2), 146–182.

Sullivan, P., W. Cole, N. Blair, E. Lantz, V. Krishnan, T. Mai, D. Mulcahy, and G. Porro. 2015. *2015 Standard Scenarios Annual Report: U.S. Electric Sector Scenario Exploration*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64072.

Swadley, A. and M. Yucel. 2011. "Did residential electricity rates fall after retail competition? A dynamic panel analysis." *Energy Policy* 39(2011), 7702-7711.

Synapse. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Prepared for: The Public Service Commission of Mississippi. Boston, MA: Synapse Energy Economics.

Synapse. 2016. *Cutting Electric Bills with the Clean Power Plan*. Boston, MA: Synapse Energy Economics.

Taber, J., D. Chapman, and T. Mount. 2006. *Examining the Effects of Deregulation on Retail Electricity Prices*. Ithaca, NY: Cornell University.

Tra, C.I. 2016. "Have Renewable Portfolio Standards Raised Electricity Rates? Evidence from U.S. Electric Utilities." *Contemporary Economic Policy* 34(1), 184–189.

TVA. 2015. *Distributed Generation-Integrated Value (IV): A Methodology to Value DG on the Grid*. Knoxville, TN: Tennessee Valley Authority.

VT Public Service Dept. 2014. Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014. Montpelier, VT: Vermont Public Service Board.

Wang, H. 2014. Do Mandatory U.S. State Renewable Portfolio Standards Increase Electricity Prices? Munich Personal RePEc Archive, Working Paper No. 59165. http://mpra.ub.uni-muenchen.de/59165/

Wilkerson, J., P. Larsen, and G. Barbose. 2014. "Survey of Western U.S. Electric Utility Resource Plans." *Energy Policy* 66 (2014): 90-103.

Williams, J.H., B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, and H. McJeon. 2014. *Pathways to deep decarbonization in the United States*. The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations.

Wiser, R. and M. Bolinger. 2016. *2015 Wind Technologies Market Report*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1005951. https://emp.lbl.gov/publications/2015-wind-technologies-market-report

Wiser, R., G. Barbose, J. Heeter, T. Mai, L. Bird, M. Bolinger, A. Carpenter, G. Heath, D. Keyser, J. Macknick, A. Mills, and D. Millstein. 2015. *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1003961. https://emp.lbl.gov/publications/retrospective-analysis-benefits-and

Würzburg, K., X. Labandeira, and P. Linares. 2013. "Renewable Generation and Electricity Prices: Taking Stock and New Evidence for Germany and Austria." *Energy Economics* 40, Supplement 1 (December): S159–71. doi:10.1016/j.eneco.2013.09.011.

Xcel. 2013. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223. Denver, CO: Xcel Energy Services.

Zarnikau, J. and D. Whitworth. 2006. "Has electric utility restructuring led to lower electricity prices for residential consumers in Texas?" *Energy Policy* 34 (2006), 2191–2200.

Appendix A. Derivation of a Simplified Model for Estimating the Impact of Distributed Solar on Retail Electricity Prices

In Section 3, we present a simplified model to estimate the impact of distributed solar on retail electricity prices, expressed in terms of the following equation:

$$(1) \quad Percent\ Change\ in\ Retail\ Price\ =\ Penetration\ \times\ \left[\frac{Solar\ Comp.\ Rate}{CoS} - \frac{VoS}{CoS}\right]$$

Here, we present the derivation for this expression. To begin, we define each of the following terms:

$$(2) \quad Average\ Retail\ Price\ (P) \equiv \frac{Utility\ Revenues\ (R)}{Retail\ Sales\ (Q)}$$

$$(3) \quad Cost\ of\ Service\ (CoS) \equiv \frac{Utility\ Costs\ (C)}{Retail\ Sales\ (Q)}$$

$$(4) \quad Value\ of\ Solar\ (VoS) \equiv \frac{Net\ Avoided\ Costs\ (\Delta C)}{Solar\ Generation\ (q)}$$

$$(5) \quad Solar\ Penetration\ Level\ (Pen) \equiv \frac{Solar\ Generation\ (q)}{Retail\ Sales\ (Q)}$$

$$(6) \quad Solar\ Compensation\ Rate\ (p) \equiv \frac{Solar\ Customer\ Revenues\ or\ Bill\ Savings\ (r)}{Solar\ Generation\ (q)}$$

With this additional nomenclature, we can restate the original equation as follows, where P_o is the utility's average price prior to the addition of distributed solar:

$$(7) \quad \frac{P}{P_o} - 1 = \frac{q}{Q} \times \left[\frac{p}{CoS} - \frac{VoS}{CoS}\right]$$

The left-hand side of the expression is the percent change in average retail electricity price, expressed here as a function of a given quantity of distributed solar generation (q), solar compensation rate (p), and value of solar (VoS). We can then proceed to derive equation (7).

We first make the simplifying assumption that utility costs are equal to utility revenues. This equivalence does not hold perfectly, particularly in the short-run between utility rate cases, but is reasonably accurate over the longer term, as rates are re-set in successive rate cases. With this assumed equivalence, the average retail price (P) is the same as the cost of service (CoS) and can thus be expressed as:

$$(8) \quad P = \frac{C}{Q}$$

To model the change in price with the introduction of distributed solar, we represent the compensation to solar customers as an explicit payment for all solar generation (such as under a feed-in tariff), rather than as a reduction in electricity sales as would occur under net metering. The two approaches are effectively equivalent from the utility's perspective, but modeling the compensation as an explicit payment allows for a more generalizable and flexible relationship that can be applied in cases without net metering or where the underlying rate structure includes charges that cannot be displaced by distributed solar.

Distributed solar thus introduces two changes to utility costs: the first is an additional cost associated with payments to solar customers (r), and the second is a net reduction (ΔC) in other operating costs and—potentially, over the long term—capital costs. From equation (8), the average retail price is thus equal to the following, where C_o is the utility's costs prior to the addition of distributed solar:

$$(9) \quad P = \frac{C_o + r - \Delta C}{Q}$$

We then multiply both the numerator and denominator by the same term ($1/C_o$) and make substitutions for various terms using equations (4), (6), and (8):

$$(10) \quad P = \frac{C_o + (p \cdot q) - (VoS \cdot q)}{Q} \cdot \frac{1/C_o}{1/C_o}$$

$$= \frac{1 + (p \cdot q)/C_o - (VoS \cdot q)/C_o}{1/P_o}$$

We can then substitute for C_o using equation (3), and with some further re-arranging of terms, arrive at equation (7):

$$(11) \quad \frac{P}{P_o} - 1 = \frac{p \cdot q}{CoS \cdot Q} - \frac{VoS \cdot q}{CoS \cdot Q}$$

$$= \frac{q}{Q} \times \left[\frac{p}{CoS} - \frac{VoS}{CoS} \right]$$

Appendix B.   Assumptions Used to Estimate RPS Compliance Costs

In Section 4.3, we present an illustrative and approximate range of the potential effect of state RPS policies on retail electricity prices in 2030. That range is based on a generic set of upper and lower bound assumptions applied to each RPS state, summarized in Table B-1. Here, we provide further details and supporting citations for the particular assumptions used in that analysis.

Table B - 1. Assumptions for estimating RPS impacts on retail electricity prices

Primary mode of RPS compliance	States	Assumptions for Low and High RPS Cost Estimates*
Unbundled RECs	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, OH, PA, RI, TX, VT	**Low:** REC prices equal $1/MWh for primary and secondary tier requirements, and $10/MWh for solar or DG tiers. Merit-order effect from main-tier and solar carve-out resources reduces retail supply costs by $5-30/MWh of RE, depending on region. No added integration or transmission costs. **High:** REC prices equal to each state's ACP. No merit-order effect. $10/MWh integration cost adder and $20/MWh transmission cost adder.
Bundled PPAs	AZ, CA, CO, HI, MI, MN, MO, MT, NC, NM, NV, OR, WA, WI	**Low:** General RPS resources yield cost savings of $10/MWh of RE, and DG tiers have zero net cost, relative to non-RE and including integration or transmission costs. No merit-order effect. **High:** General RPS resource cost per MWh-RE equal to historical compliance cost for each state, plus $10/MWh for integration costs and $20/MWh for transmission costs. Net cost of DG carve-out resources equal to $100/MWh-RE. No merit-order effect.

* All $/MWh values are stated in terms of real 2015 dollars, and refer to dollars per MWh of renewable electricity.

We first distinguish between states where RPS compliance is achieved primarily through unbundled RECs and those where compliance occurs primarily through bundled power purchase agreements (PPAs) for renewable electricity. The former set consists entirely of states with retail choice, while the latter consists primarily of states where regulated retail suppliers continue to conduct long-term procurement for most load. For each set of states, we then estimate retail price impacts based on a standardized set of low and high assumptions for: (a) the incremental cost of procuring renewable electricity or RECs relative to non-renewables, (b) the merit-order effect, (c) incremental transmission costs, and (d) renewables integration costs.

Unbundled REC States: For these states, REC prices in the low case are roughly equivalent to those currently observed in voluntary REC markets and in highly oversupplied RPS markets, such as Texas. In the high case, REC prices are instead assumed to be equal to the corresponding alternative compliance

payments (ACP), as would occur under sustained shortages in REC supplies. We also consider two indirect impacts on retail electricity prices. The first of these is the "merit-order effect": that is, the tendency of low-marginal-cost renewables to suppress wholesale electricity market prices. Great uncertainty exists around the magnitude and longevity of this effect. For the high-cost case, we assume no merit order effect, as might be expected over the long-run, as capacity additions and retirements in the power market fully adjust to the presence of RPS resources. For the low-cost case, we use the upper bounds estimated in Wiser et al. (2016), which vary by region: $5/MWh of renewable energy in Texas, $17/MWh in PJM states, and roughly $30/MWh in Northeastern states.[20] We also considered indirect RPS costs associated with socialized integration costs and transmission expansion costs. Our low RPS cost case assumes zero additional integration and transmission costs, while our high case includes a $10/MWh adder for integration costs and a $20/MWh adder for transmission costs.[21]

Bundled PPA States: RPS costs in these states consist of the incremental cost of RE resources procured to meet RPS obligations, relative to non-renewable resources that would have otherwise been procured. For the low case, we assume that resources used to meet general RPS obligations yield a net *savings* of $10/MWh of RE in 2030, based on the lower bound estimate from Mai et al. (2016). This value is inclusive of transmission and integration costs. For the high case, we instead assume that the incremental cost per MWh of general RPS resources is equal to the average historical cost per MWh in each state. Historical compliance costs for general RPS resources have varied from -$10/MWh to $50/MWh across these states, reflecting differences in policy and market conditions, as well as differences in RPS cost calculation methodologies (Barbose 2016). Those historical compliance-cost data typically do not reflect incremental transmission or integration costs; we therefore apply adders for transmission and integration costs, at the same levels used for unbundled REC states. For DG carve-outs, we assume higher costs than general RPS resources in both the low and high cost cases, reflecting the higher cost of DG resources compared to utility-scale RE. We do not include any merit order effect

---

[20] These upper bounds are generally consistent with, though in some cases lower than, other estimates in the literature. For example, IPA (2013) estimated a value of $21/MWh for wind in the Midwest. A report on transmission in MISO (Fagan et al. 2012), estimated the price suppression benefits from 20 GW and 40 GW of wind, implying a wholesale price impact of $100-130/MWh of wind. Perez et al. (2012) estimate the wholesale price effect of solar in the mid-Atlantic region to be around $55/MWh of solar. A broad literature review conducted by Würzburg et al. (2013), drawing primarily on studies from Europe, created a common metric of $/MWh of RE per % of RE within the generation mix. The median value across studies was $0.73/MWh-RE per % RE. Using this value would lead to estimates of $3 to $50/MWh of RE, depending on each state's RPS target in 2030.

[21] Accounting for integration and transmission costs is complicated, as some costs are charged directly to projects served and are therefore implicit in the REC price or the price of the PPA. Only those costs that are "socialized" are appropriate for inclusion in a separate cost adder. The integration cost assumptions used within the present analysis are based loosely on Wiser and Bolinger (2016), which reviewed 30 wind integration studies in the U.S., and found that virtually all estimated integration costs less than $10/MWh, even at penetration levels >20%, and most estimated costs less than $5/MWh. For transmission costs, we base our upper bound cost adder on Enernex (2010) and GE Energy (2010), which estimated total transmission costs associated with large scale build-out of renewable energy in the Eastern and Western Interconnections, respectively. The studies estimated total transmission costs on the order of $400/kW, which equates to roughly $20/MWh (assuming a 15% capital recovery factor and 35% capacity factor). These cost estimates include both dedicated transmission assets for specific renewables projects as well as network upgrades, and therefore likely overstate socialized transmission costs. As one other point of reference, Mills et al. (2012) reviewed planning studies in the U.S. and found a median cost of transmission for wind energy equal to $15/MWh.

for these states, as most retail load in these states is served through long-term contracts, thus any effect on wholesale prices would have limited impact on retail prices.