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A retrospective analysis of the market price response to distributed photovoltaic generation in California

Michael T. Craig[a,*], Paulina Jaramillo[b], Bri-Mathias Hodge[a], Nathaniel J. Williams[b], Edson Severnini[c]

[a] National Renewable Energy Laboratory, 15013 Denver West Parkway, MS ESIF200, Golden, CO 80401, United States
[b] Department of Engineering and Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, 129 Baker Hall, Pittsburgh, PA 15213, United States
[c] Heinz College, Carnegie Mellon University, 4800 Forbes Avenue, Pittsburgh, PA 15213, United States

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ABSTRACT

Due to rapid growth of distributed solar photovoltaic (PV) capacity in the U.S., numerous "value of solar" studies have attempted to quantify avoided costs associated with distributed PV. One such avoided cost that has received little attention is the market price response, or how distributed PV generation reduces utilities' procurement costs and, consequently, consumers' costs through reduced wholesale electricity prices in the short-term. We quantify the reduction in day-ahead wholesale electricity prices to distributed PV generation in California (CA) from 2013 through 2015. Using a database of all distributed PV systems in the three CA investor owned utilities, we estimate historic hourly distributed PV generation using three methods that we validate with metered generation from 205 PV systems. Via multiple linear regression, we then estimate electricity price reductions due to distributed PV generation. Across the three methods used to estimate PV generation, distributed PV generation reduced hourly median (mean) wholesale electricity prices by up to \$2.7–3.1/MWh (\$2.9–3.2/MWh) ($\$_{2015}$), or by 7–8% (8–9%). Lower wholesale prices reduced utilities' energy procurement costs in the day-ahead market by up to \$650–730 million ($\$_{2015}$) from 2013 through 2015. These avoided costs are similar to other avoided costs commonly included in value of solar studies.

1. Introduction

Installed solar photovoltaic (PV) capacity has grown rapidly in recent years, increasing from 2.5 to 21.7 GW in the U.S. from 2010 to 2015 (Ardani and Margolis, 2011; U.S. Energy Information Administration, 2016) and from 10 to 230 GW globally over the same period (International Energy Agency Photovoltaic Power Systems Programme, 2017). In the U.S., numerous factors have driven this growth, including falling PV panel and balance-of-system costs (Barbose et al., 2016) and policy support such as deployment mandates and financial incentives (Solangi et al., 2011; U.S. Department of Energy et al., 2017). Forecasts project continued rapid growth in installed PV capacity in the U.S. (Cole et al., 2017) and globally (Creutzig et al., 2017).

PV projects can be broadly categorized as utility-scale or distributed PV. Utility-scale PV typically connects to the transmission grid, while distributed PV, also known as behind-the-meter or rooftop solar, generates electricity to be consumed on-site by industrial, commercial, or residential facilities. In the U.S., utility-scale PV plants typically range from 1 to 20 MW (U.S. Energy Information Administration, 2015), whereas residential distributed PV systems typically range from 2 to 10 kW (California Distributed Generation Statistics, 2017a). As of 2015, distributed PV accounted for 45% of installed PV capacity in the U.S. (U.S. Energy Information Administration, 2016).

Rapid growth of distributed PV has led to questions regarding its costs and benefits. In response, numerous "value of solar" studies have attempted to quantify incurred and avoided system costs associated with distributed PV generation in order to determine how to compensate distributed PV generation (Hansen et al., 2013; Patel et al., 2015; Taylor et al., 2015). While avoided and incurred costs included in these studies vary widely (Hansen et al., 2013; Patel et al., 2015), avoided costs can include avoided power system costs, such as through deferred or reduced grid infrastructure investment, reduced system losses, and avoided generation (Cohen et al., 2016; Hansen et al., 2013; Patel et al., 2015); avoided environmental and health costs due to reduced global and local air emissions (Hansen et al., 2013; Vaishnav et al., 2017; Wiser et al., 2016); and social and reliability benefits (Hansen et al., 2013; Patel et al., 2015). Incurred costs can include grid integration

* Corresponding author.
E-mail address: Michael.Craig@nrel.gov (M.T. Craig).

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costs, such as grid infrastructure upgrades and higher ancillary service requirements, and subsidies (Hansen et al., 2013; Patel et al., 2015). Avoided and incurred costs of distributed PV vary significantly by location, PV penetration, and other variables (Cohen and Callaway, 2016; MIT Energy Initiative, 2016; Vaishnav et al., 2017).

This paper focuses on one avoided cost associated with distributed PV that has received less attention than other benefits (Hansen et al., 2013; Patel et al., 2015), namely the market price response to distributed PV generation, or how distributed PV generation suppresses wholesale electricity prices in the short-term. Since electricity generated by distributed PV partially or fully meets on-site electricity demand, distributed PV reduces net electricity demand. In the near-term, given a static supply curve, reduced demand eliminates the need for marginal, high cost generation, thus suppressing wholesale electricity prices (Hirth, 2013). Lower wholesale prices, in turn, reduce utility expenditures in wholesale markets, which should ultimately reduce consumers' costs through lower retail rates. Note that reduced generation due to reduced net demand constitute a separate category of avoided costs typically referred to as energy avoided costs (Hansen et al., 2013).

Notably, short-term reductions in electricity prices due to distributed PV generation may alter generator retirements and investments, which can affect electricity prices in the long-term. Additionally, revenues originally obtained by producers in wholesale energy markets may instead move to capacity markets or similar mechanisms (Borenstein, 2008). Such long-term effects may reduce (or eliminate) short-term avoided costs due to reduced wholesale electricity prices. Thus, the market price response is indirectly linked to capacity avoided costs, as the latter partly depends on the gap between generator fixed costs and market compensation, which varies with market prices (Hansen et al., 2013). To understand the extent of short-term price effects and potential long-term market shifts due to distributed PV, here we quantify short-term price reductions and avoided costs, deferring long-term analyses to future work.

Numerous studies have examined how renewables affect wholesale electricity prices (Bode and Groscurth, 2010; Brancucci Martinez-Anido et al., 2016; Clò et al., 2015; Gelabert et al., 2011; Hirth, 2013; Morthorst et al., 2010; Tveten et al., 2013; Woo et al., 2016), but most have focused on utility-scale renewables or have not differentiated between utility-scale and distributed facilities. Studies on wholesale price, or "merit-order", effects of utility-scale renewables fall into two groups. One group conducts retrospective or *ex-post* analyses using empirical data (Clò et al., 2015; Gelabert et al., 2011; Tveten et al., 2013; Woo et al., 2016). Due to the rapid deployment of renewables in response to feed-in tariffs and other policies, most studies in this group have focused on European nations (Clò et al., 2015; Gelabert et al., 2011; Tveten et al., 2013). Conversely, Woo et al. (2016) focused on California. Using multiple linear regression, they found that each hourly GWh increase in utility-scale solar and wind generation decreased day-ahead locational marginal prices by \$2–5/MWh and \$1–3/MWh, respectively, from 2013 through 2015. The second group of studies assesses merit-order effects of utility-scale renewables with dispatch models or simulation (Bode and Groscurth, 2010; Brancucci Martinez-Anido et al., 2016; Hirth, 2013). Bode and Groscurth (2010), for instance, used a simplified dispatch model to estimate how parametrically increasing capacities of PV would depress future electricity prices relative to no additional PV. Similar analyses have also been conducted on energy efficiency, where wholesale price effects are called "demand reduction induced price effects" (Industrial Energy Efficiency and Combined Heat and Power Working Group, 2015; Mims et al., 2017).

Unlike the above studies, McConnell et al. (2013) conducted a retrospective analysis focused on the market price response to distributed PV in Australia. The authors estimated electricity generation by a representative PV system in four state capitals with historic meteorological and solar irradiance data, then scaled generation from those four PV systems to estimate generation by an assumed 1–5 GW of installed PV. By coupling these generation estimates with a dispatch model, they found that distributed PV would reduce wholesale electricity prices throughout the year but particularly in the summer, yielding total cost savings of \$310–970 million and \$150–550 million ($\$_{2015}$) in 2009 and 2010, respectively, with 1–5 GW of distributed PV. Notably, by estimating generation by a single representative system in only four locations, McConnell et al. ignored heterogeneity among distributed PV systems' orientations and locations. Additionally, rather than using historic PV capacity and market data, McConnell et al. simulated the effects of parametrically increasing distributed PV capacities.

In this paper, we quantify the market price response to distributed PV generation in California from 2013 through 2015. As of 2015, California installed 7.3 GW of utility-scale thermal and PV capacity (California Energy Commission, 2017) and 3.4 GW of distributed PV capacity. Using a database of all distributed PV systems (439,010) in the three California investor owned utilities (IOUs), namely Pacific Gas and Electric (PGE), Southern California Edison (SCE), and San Diego Gas and Electric (SDGE), we estimate historic hourly generation by each distributed PV system while accounting for heterogeneity in PV system orientation and location. Using historic price data and multiple linear regression, we then estimate how distributed PV generation reduced wholesale electricity prices in the day-ahead market. We also test the sensitivity of our results to PV efficiency degradation and high inverter loading ratios.

2. Methods

2.1. Estimating distributed PV generation

From the Net Energy Metering ("NEM") dataset, we obtain system information, including zip code, capacity, orientation, and interconnection date, for all commercial, residential, and industrial distributed PV systems in PGE, SCE, and SDGE approved for interconnection as of 2016 (California Distributed Generation Statistics, 2017a) (see Table 1 for summary statistics and Appendix A.1 for histograms of PV system orientations). Since we lack metered generation, we estimate hourly electricity generation by each PV system in the NEM dataset from 2013 through 2015. To do so, we validate four methods (summarized in Table 2) with metered generation from 205 distributed PV systems, then apply the three most accurate methods to estimate generation by all distributed PV systems. In so doing, we hedge against biases of any single method. Across methods, we assume PV systems begin generating electricity on their interconnection approval date. Given that 99.5% of PV systems with tracking data in the NEM dataset

Table 1
Summary statistics for distributed PV systems in the NEM and CSI datasets interconnected through 2015, the end of our period of analysis.

Summary statistic	Value in NEM dataset	Value in CSI dataset
Total number of PV systems	439,010	492
Total capacity of PV systems [MW]	3434	3
Average PV system capacity [kW]	8	5.9
Median interconnection date	Apr. 9, 2014	Sep. 3, 2008
Average nominal efficiency of 10 most common panels [%]	16.6	15.8
Percent of PV systems with tracking data that are fixed array [%]	99.7	94
Minimum / average / maximum azimuth [°]	0 / 174 / 360	0 / 191 / 355
Minimum / average / maximum tilt [°]	0 / 18 / 90	0 / 21 / 75
Number of PV systems in PGE / SCE / SDGE	211,026 / 156,423 / 71,561	201 / 188 / 103
Total capacity of PV systems in PGE / SCE / SDGE [MW]	1772 / 1210 / 451	1.4 / 0.9 / 0.6