1. Refer to the Application, Volume I, page 1, under the section heading 2 "Description of Proposed Site." Table 1 provides information regarding the land cover in the proposed project site. State whether the land cover class information derived from the 2016 U.S. Geological Survey is the most recent information.

RESPONSE: The 2016 U.S. Geological Survey was released in 2019 and is the most recent information available from this dataset.

WITNESS: April Montgomery, SWCA

2. Refer to the Application, Volume I, pages 2–3, under the section heading 3 "Public Notice Evidence."

a. Confirm that there are 162 property owners that own property adjoining the proposed solar site.

b. Refer to the Application, Volume I, Appendix B. Of the 162 adjoining property owners listed in this appendix, identify any property owner that did not receive the December 7, 2020 letter. For those property owners that did not receive the letter, provide any follow-up measures performed by AEUG Madison to provide these owners with notice.

c. State whether any of these adjoining property owners provided feedback regarding the proposed solar facility site. If so, state how AEUG Madison responded to those feedback.

RESPONSE:

a. For the Notices of Application, we used the County's parcel data information to identify abutting parcels and nearby subdivisions (image below). We provided that information to Madison County and asked them to provide the names, addresses and other contact information for the parcel owners. The list of adjoining parcel owners received from the county was ultimately used to create the Notices of Application mailing list.

b. Out of the 162 mailers that were sent to adjoining property owners, 6 of them were not delivered and were returned to ACCIONA in the mail. We did not become aware of the returned mailers until after the Public Meeting had already been held, so there was no way in knowing which neighboring landowners did not receive the mailer at the time of the Public Meeting.

c. AEUG Madison Solar had received direct follow up emails from several of the adjoining property owners. Most of the feedback came in the form of questions about how the project would affect their individual properties. Some of the primary concerns coming from these neighbors included viewshed/visibility of the project, potential flooding and runoff issues created by the project, and the idea that the solar project would negatively affect their property values.

AEUG Madison Solar responded to all follow up emails and calls. In many cases, setting up one on one meetings and communications to address their comments and feedback, to answer any questions or concerns they may have had about the project, and to provide any requested resources that would give them a better understanding of the project and the development process.

Furthermore, AEUG Madison Solar was able to perform viewshed assessments with some of the neighbors who were closest to proposed project infrastructure. Discussions were had about their properties and proximities to proposed project infrastructure. These concerns were assessed and taken into consideration for future layout designs. Since then, updated project layouts have accounted for some of these considerations

WITNESS: Austin Roach

3. Refer to the Application, Volume I, pages 4–6, under the section heading 6 "Public Involvement Report."

a. State whether there were any feedback received from the public meetings that were conducted. If so, state how AEUG Madison responded to those feedback.

b. The last sentence of this section states "In some cases, AEUG Madison Solar has even addressed the community's concerns by amending its Project design/layout." Provide specific details of the concerns that were raised and how AEUG Madison revised the solar project's design or layout to address those concerns.

RESPONSE:

a. There was excellent dialogue at the public meetings. AEUG Madison Solar tried its best to respond to questions, as best it could. Responses from the drive-thru BBQ event are attached. Similar questions on the project's layout, regulatory oversight, property values, economic impact, and environmental protection were addressed at the August 6, 2020, public meeting.

b. As stated in our compliance, per the Application, AEUG Madison Solar has had various one-on-one meetings and communications with numerous neighboring landowners around the project area. Some of the primary concerns coming from these neighbor meetings included: viewshed/visibility of the project, potential flooding and run off issues created by the project, and the idea that the solar project would negatively affect their property values.

In certain cases, AEUG Madison Solar was able to perform viewshed assessments with some of the neighbors, where discussions were had about their properties and proximities to proposed project infrastructure. These concerns were assessed and taken into consideration for future layout designs. Since then, updated project layouts have taken into account some of these considerations.

WITNESS: Austin Roach

Madison County

Drive-Thru BBQ Q&A

Question/Answer	Assignment
How will local government, schools and counties benefit from a project like this?	David
A: Utility scale solar projects pay property taxes which directly support things like local government, first responders and schools. This increase in revenue also comes without a significant increase in the demand for these same services, so they are a net gain for the community.	Kyle
Has an economic impact analysis been performed on this project?	David
We have signed a contract with an independent economic analyst who will be doing an assessment of the project and its impact.	Adam
Will the local community have access to the jobs created by this project?	David
As I mentioned in my comments, the O&M team will absolutely be looking for people who are from the community, love the community and want to stay in the community. We will be looking for people who have the interest, ability and commitment. I want a stable team that will be there for a long time.	Adam
How long will construction last?	David
We are anticipating that the construction of this project will take about a year. We are hoping that we will be able to break ground next year and will have the project begin operation in 2022.	Kyle
What will you be planting around the site? How will you maintain the area around the panels once the site is operational?	David
Vegetation management of the site is the issue that I have been and will be looking at very closely. Ideally, we are hoping to use	Adam

some kind of native planting that doesn't have to be mowed every week. We will be looking at a wide range of options including native plants, grazing forbes and plantings that support pollinators, like honey bees.	
Are there fire or other safety issues with solar farms?	David
When you operate facilities where electricity is generated, safety is always the top concern. And the key to safety is having a team that understands compliance and best practices, and having a company that invests in safety and training. We are proud of that record and it will be my job the make sure we do things the right way in Fleming County.	Adam
Are there noise or glare impacts from solar?	David
Solar panels are passive devices that do not produce noise, but the inverters that change the current of electricity from DC to AC do produce a slight hum that is not audible past the property boundaries. As for glare, for optimal power generation, solar panels are designed to absorb sunlight, not reflect it. In fact, photovoltaic panels actually cause less glare than standard home window glass, snow, white concrete and energy-efficient white rooftops. Solar modules are coated with anti-reflective materials that maximize light absorption. Further, it is common for airports to install solar arrays for power generation, without experiencing glare issues.	Kyle

In case we're asked in open Q&A	
Q: How will this end my property values?	
A: The presence of a solar field has shown no measurable negative impact on the value of adjacent properties. Various studies, including studies for other proposed solar development projects in Kentucky, show that solar fields have had or are not anticipated to have any adverse impact on property values. This project will require a property value impact assessment as part of the Kentucky State Siting	Kyle

Board process. There are several thoughts on why this is, panels are low profile –many homes have panels, so they are accepted, they are often surrounded by natural plantings.	
Q: **How about setbacks?**	Adam
A: As a company we exceed industry best practices intended to mitigate impacts of our projects on adjacent landowners and this project will be no different.	
Q: **Where will your panels come from?**	Kyle
A: The panels for this project, like all of the equipment and materials, will be procured through a competitive bid process. Right now there is an incredible demand for solar panels in the US. Today in the US there are 2 million solar installations. In 2021 it is expected the country will add 3 million new solar installations and in 2023, another 4 million installations. Pricing, performance, product availability among other things will be considered when making the final procurement decisions. Whatever panels are procured will need to meet industry safety specifications.	
Q:When will you sign a Power Purchase Agreement	Adam
A:We have serious conversations going on and hope to close something very soon. That's all I am allowed to say.	
Q:Health impacts? Pacemakers, etc	Kyle
A: Solar panels are widely used for various functions including calculators, watches, and other miscellaneous household electronic devices. They are also extensively used on the rooftops of residential structures to provide and offset energy consumption. The technology has been extensively studied, and no proven health risks from solar fields have been identified. In fact, the overall impact of solar development on human health is	

overwhelmingly positive. Solar fields are known for having a positive benefit on air quality. They generate clean, renewable power with zero air emissions and often replace older and less-efficient fossil fuel-based sources of power with significant air emissions. Various studies can be provided that show that solar projects contribute to lower risks for respiratory issues and heart attacks. A study from the National Renewable Energy Laboratory https://www.nrel.gov/docs/fy07osti/41998.pdf shows that this corresponds to a lower risk of respiratory issues and heart attacks. Solar fields are generally not associated with health risk from electromagnetic fields (EMFs). Humans are exposed to EMFs in their daily life, such as from a refrigerator or microwave oven. Similarly, EMFs generated within the solar fields are at a low level and not enough to harm humans. Additionally, any exposure to EMFs at a solar field would be within the perimeter fence and even then, the level is not high enough to cause harm. We will have operations employees at the solar farm, and their safety is a priority. If there is concern about high EMFs from high-voltage transmission lines, such a high-voltage transmission system already exists in this area. You can read more about EMFs on the U.S. Environmental Protection Agency's website: https://www.epa.gov/radtown/sources-electric-and-magnetic-radiation	
Q: **Long-term-impact to crop land**	Kyle
A: The solar leases are voluntary; landowners are able to assess what is the most economic use of their land when determining whether to participate. At the end of the project's useful life, approximately 30+ years, the land is returned – restored and rested – to the landowner to return to agricultural production	

or other uses.	

4. Refer to the Application, Volume I, Appendix C – Public Involvement Documents.

a. On slide 17 of the Madison Count Solar Public Meeting August 6, 2020 PowerPoint presentation, state what is meant by the following statement and how such statement is applicable to the proposed solar project: "Social impact projects designed for every project ACCIONA builds."

b. Regarding the commitment that a portion of the proposed project's revenue will be reinvested in the community, state how AEUG Madison will honor this commitment.

c. Refer to the last PowerPoint presentation in this appendix, slides 15–16. Provide the questions and answers that were discussed during this presentation.

RESPONSE:

a. ACCIONA prides itself on being a company that engineers, designs, constructs, owns and operates renewable energy facilities. Our commitment to communities begins with development and lasts throughout the life of the project. As part of this commitment, ACCIONA includes a Social Impact Management program with each of its projects. This program works with local stakeholders to identify local community needs, often in the areas of education, environmental, and wellness efforts. As an example, in the last decade ACCIONA has awarded more than $250,000 in scholarships to students graduating from high schools located in our communities. This is applicable to the proposed Madison Solar Project because we plan to support Madison County and the city of Richmond through various social impact projects, similarly as we have done for our projects in other communities.

b. Once the project becomes operational, we will reach out to local community stakeholders to determine projects that will impact the community. We are performing these social projects on our existing operating projects in Texas.

c. Please see the attachment provided in response to Question 3a above.

WITNESS: Austin Roach / Mary Connor

5. Refer to the Application, Volume III, Appendix F – Visual Assessment Report.

a. On the first page of the report, reference is made to the size of the project site being 2,021 acres. Reconcile this statement with the references to the project site being 1,770 acres (Application, Volume I, Section 2) and 1,100 acres (Application, Volume I, Section 3).

b. Where the visual assessment determined that the view of the solar facility would be unobstructed such as at VP-03 (Three Forks Substation) and VP-11 (Red House Road (North)), state how AEUG Madison will mitigate the view shed impacts at these locations.

RESPONSE:

a. A Project Area evolves as a project advances through the development process and can be broken into three categories: the study area, the project boundary and the project footprint. The study area is the broadest and includes more acreage than will be ultimately required for construction and operation of a facility. The study area is purposefully broad because it anticipates that resources, such as wetlands, may be identified that require the project be redesigned to avoid impacts. The study area acreage is reflected in the Visual Assessment Report (Volume III Appendix F) as 2,021 acres.

The project footprint represents the narrowest measure of a project area as it represents those acres that will host project components (panels, tracking systems, inverters, operations and maintenance facilities and substations) that will exist on the site for the life of the project. AEUG' Madison's project footprint is anticipated to be 1,100 acres as noted in Volume 1 Section 3.

The project boundary encompasses the entire project footprint and extends to include the fenced area, setbacks, and the corridors of buried and above ground connector lines that join the distributed components of a project. The total area of the project boundary for AEUG Madison is anticipated to 1,770 acres as stated in Volume I Section 2 of the Application.

b. AEUG Madison is engaged in evaluating visual impacts across the project. Consistent with Condition #8 of the Madison County Board of Adjustments Conditional Use Permit for this project, AEUG Madison will provide a vegetative buffer where necessary, but not where the project is not visible to a dwelling or roadway by virtue of existing topography. AEUG will coordinate this effort with the Madison County Planning and Development Director.

WITNESS: April Montgomery, SWCA Environmental Consultants

6. Refer to the Application, Volume I, Appendix G, Figure 1, page 4. Provide a copy of the Solar Market Insight Report 2019 Year in Review report.

RESPONSE: A copy is attached.

WITNESS: David Loomis

March 2020

U.S. Solar Market Insight

Executive summary

2019 Year in review

About the report

U.S. Solar Market Insight® is a quarterly publication of Wood Mackenzie and the Solar Energy Industries Association (SEIA)®. Each quarter, we collect granular data on the U.S. solar market from nearly 200 utilities, state agencies, installers and manufacturers. This data provides the backbone of this U.S. solar market insight® report, in which we identify and analyze trends in U.S. solar demand, manufacturing and pricing by state and market segment. We also use this analysis to look forward and forecast demand over the next five years. All forecasts are from Wood Mackenzie, Limited; SEIA does not predict future pricing, bid terms, costs, deployment or supply.

- References, data, charts and analysis from this executive summary should be attributed to "Wood Mackenzie/SEIA U.S. Solar Market Insight®."
- Media inquiries should be directed to Wood Mackenzie's PR team (WoodmacPR@woodmac.com) and Morgan Lyons (mlyons@seia.org) at SEIA.
- All figures are sourced from Wood Mackenzie. For more detail on methodology and sources, visit www.woodmac.com/research/products/power-and-renewables/us-solar-market-insight/.
- Wood Mackenzie partners with Clean Power Research to acquire project-level datasets from participating utilities that utilize the PowerClerk product platform. For more information on Clean Power Research's product offerings, visit https://www.cleanpower.com/.

Our coverage in the U.S. Solar Market Insight reports includes all 50 states and Washington, D.C. However, the national totals reported also include Puerto Rico and other U.S. territories.

Detailed data and forecasts for 50 states and Washington, D.C. are contained within the full version of this report, available at www.woodmac.com/research/products/power-and-renewables/us-solar-market-insight/.

Note on U.S. Solar Market Insight report title: The report title is based on the quarter in which the report is released, as opposed to the most recent quarter of installation figures. The exception is our year in review publication, which covers the preceding year's installation figures but is published in the first quarter of the year.

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1. Key figures

Please note this edition of Solar Market Insight does not account for impacts of the coronavirus outbreak.

At the time of publication, the full impacts of the coronavirus outbreak on the solar industry were still developing. Given the dynamic nature of the outbreak, it is too early to incorporate any changes into our outlooks with enough certainty. Wood Mackenzie's solar team is tracking industry changes closely as they relate to solar equipment supply chains, component pricing and project development timelines, taking these impacts into consideration for future publications.

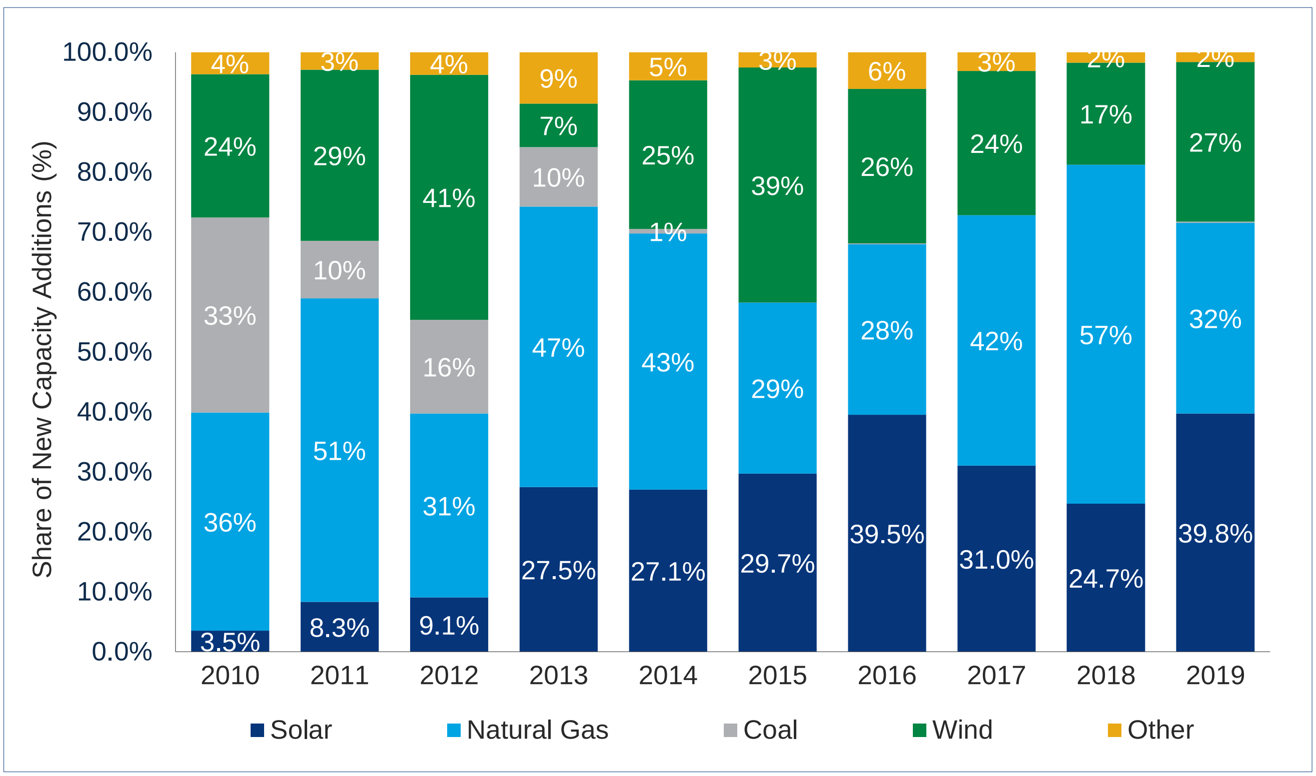
- Solar accounted for nearly 40% of all new electricity generating capacity added in the U.S. in 2019, the largest annual share in the industry's history.
- In 2019, the U.S. solar market installed 13.3 GW_{dc} of solar PV, a 23% increase from 2018.
- Cumulative operating photovoltaic capacity in the U.S. now exceeds 76 GW_{dc}, up from just 1 GW_{dc} at the end of 2009.
- The U.S. saw record-setting residential solar capacity added in 2019, with more than 2.8 GW_{dc} installed.
- A total of 30.4 GW_{dc} of new utility PV projects were announced in 2019, bringing the contracted utility PV pipeline to a record high of 48.1 GW_{dc}.
- Non-residential PV declined slightly in 2019 with 2 GW_{dc} installed, as policy shifts in states including California, Massachusetts and Minnesota continue to impact growth.
- Community solar continues to expand its geographic diversification, and it experienced a third consecutive year of more than 500 MW installed.
- Wood Mackenzie forecasts 47% annual growth in 2020, with nearly 20 GW_{dc} of installations expected. In total, more than 9 GW were added to the five-year forecast since last quarter to account for new utility-scale procurement.
- Total installed U.S. PV capacity will more than double over the next five years, with annual installations reaching 20.4 GW_{dc} in 2021 prior to the expiration of the federal Investment Tax Credit for residential systems and a drop in the commercial credit to 10% (under the current version of the law).
- By 2025, one in every three residential solar systems and one in every four non-residential solar systems will be paired with energy storage.

2. Introduction

A note about the impacts of the coronavirus outbreak: At the time of publication, the full impacts of the coronavirus outbreak on the solar industry were still developing. Given the dynamic nature of the outbreak, it is too early to incorporate any changes into our outlooks with enough certainty. Wood Mackenzie's solar team is tracking industry changes closely as they relate to solar equipment supply chains, component pricing and project development timelines, taking these impacts into consideration for future publications.

2019 recap: In 2019, the U.S. solar market installed 13.3 gigawatts-direct current (GWdc) of solar photovoltaic (PV) capacity, a 23% increase year-over-year. Residential solar continues to see healthy installation volumes, growing 15% over 2018 levels – the highest annual growth rate since 2016. Conversely, total non-residential PV (which includes commercial, government, nonprofit and community solar) declined relative to 2018 due to policy transitions and persistent interconnection issues in key commercial markets. More than 8.4 GWdc of utility-scale PV capacity came online in 2019, up 37% from 2018, with new procurement growing the contracted pipeline to 48.1 GWdc. Across all market segments, solar PV accounted for nearly 40% of all new electricity-generating capacity additions in 2019 – its highest-ever share of new generating capacity.

New U.S. electricity-generating capacity additions, 2010-2019



Source: Wood Mackenzie, Federal Energy Regulatory Commission (for category "All other technologies")

Public-safety power shutoffs associated with California wildfires, new-build home solar and emerging market growth combine for a record-breaking close to the decade in residential solar

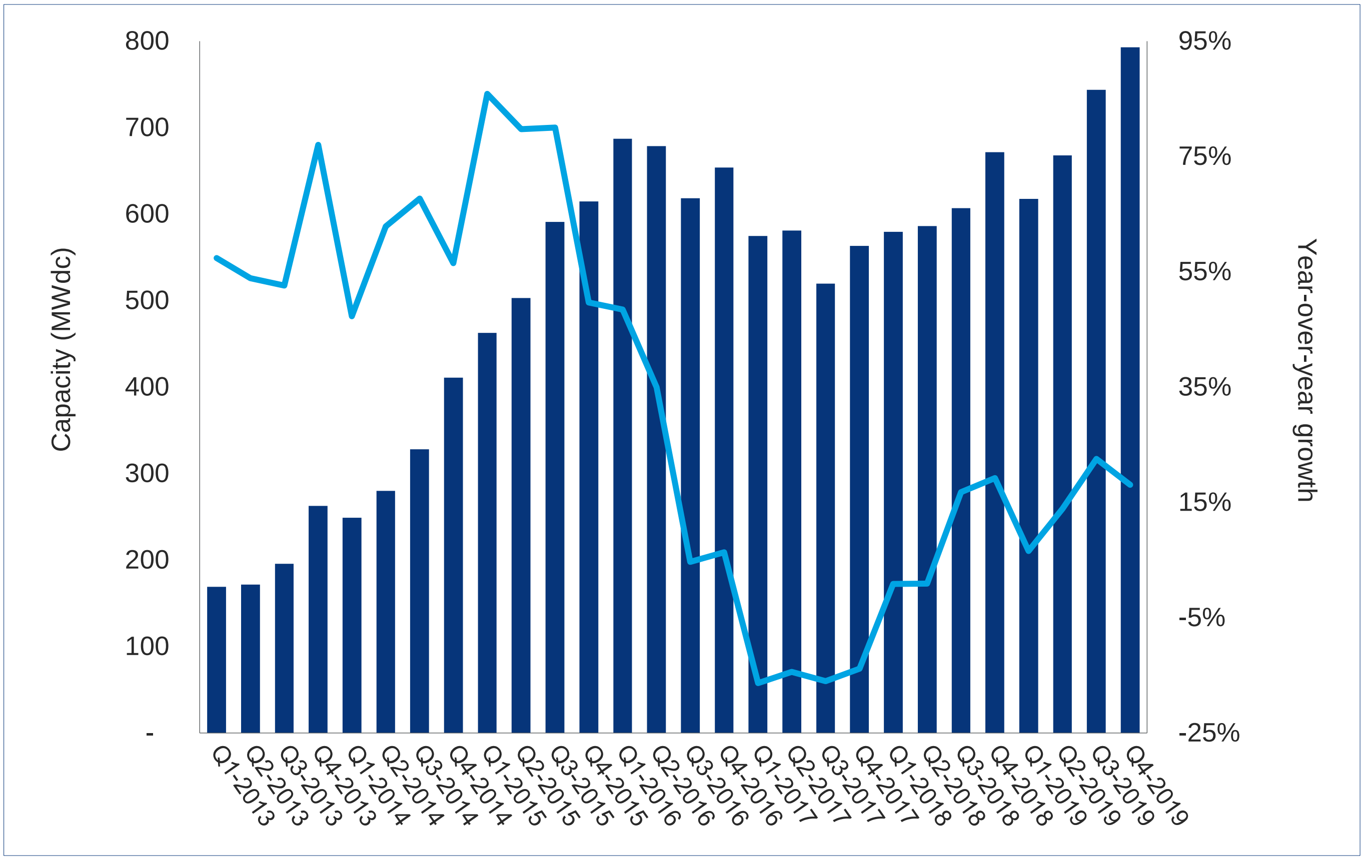
After years of steady double-digit-percentage growth through 2016, the U.S. residential sector contracted from 2016 to 2017 as national installers pulled back across critical geographies in California and the Northeast. On a national level, 2019 exhibited a return to pre-2016 growth for residential solar as the segment saw annual growth of 15% while achieving its highest installation volumes in history.

A crucial driver of growth for residential PV has been the public-safety power shutoff (PSPS) events in California. Beginning in H1 2019, these power shutoffs provided a key incentive for homeowners to purchase solar, increasingly paired with storage. With PSPS events leaving hundreds of thousands of utility customers without electricity, solar-plus-storage as a resiliency measure has catalyzed the residential solar market.

Meanwhile, California saw increased activity in the new-build home solar space as installers geared up for compliance with the recently enacted state mandate. These combined factors materialized into record-breaking installations in Q4 2019, making California the first U.S. state to install more than 300 MW in a single quarter and ending the year with more than 1 GW of residential solar installed for the third time in history.

Beyond strong growth in California and stable volumes across Northeast markets, 2019 also demonstrated the ongoing trend of geographic diversification. In 2010, California was the only state to deploy more than 100 MW of residential installations. By the middle of the last decade, six states had reached that threshold. In 2019, that number increased to eight with Texas and Nevada joining the list. Meanwhile, Florida cemented its place as the second-largest residential market in 2019 – the first time a low-penetration, non-incentivized market has achieved that designation.

Residential quarterly installation volumes, Q1 2013-Q4 2019



Source: Wood Mackenzie

Non-residential PV enters a second consecutive year of annual decline

In contrast to the growth trajectory of the residential market, non-residential installations continued to be hampered by a handful of state-specific regulatory cliffs and policy reforms in 2019. Major policy shifts continued to hinder development in the core non-residential markets of California, Massachusetts and Minnesota. In the case of California, installations declined year-over-year stemming from the transition to new time-of-use rates and the resulting damage to the favorability of project economics. In Massachusetts, non-residential deployment numbers continue to be limited by interconnection delays and the ongoing National Grid cluster study, despite a pipeline of mechanically complete projects that aren't yet producing power. As a result, the Bay State had its lowest annual non-residential PV installed capacity total since 2013.

Positive policy developments in New York, Maryland, Maine and New Jersey over the first half of 2019 will boost the non-residential market from 2020 through 2022 before a decline in 2023 begins in response to the step-down of the solar Investment Tax Credit under current federal law.

New utility procurement breaks records; 100% renewables targets and offsite corporate demand boost long-term outlook

Utility PV maintained the largest share of 2019 installed capacity in the U.S., representing 63% of all PV capacity installed during the year. A total of 4.4 GWdc came online in Q4, resulting in 8.4 GWdc of capacity additions for the year.

A total of 10.0 GWdc of projects are currently under construction. While this falls short of the record high of 10.4 GWdc, the fact that 4.0 GWdc of new projects began construction and 4.4 GWdc were completed in Q4 is a testament to the strong demand for U.S. utility PV. With 30.6 GWdc of new projects announced in 2019, the utility PV development pipeline has reached 48.1 GWdc, another record high. It is likely that not all projects announced in 2019 were able to qualify for the 30% investment tax credit (ITC). Going forward, the abnormally high rate of new project announcements will likely start slowing down given that many developers were closing deals prior to the 2019 year-end decrease in the ITC.

The U.S. utility PV market is poised to see 83.2 GWdc installed from 2020 to 2025, more than double what was installed over the last five years. The high demand for utility solar is sustained by several factors. With power-purchase agreement prices ranging from $16 to $35/MWh, the economic competitiveness of solar with other generation sources is driving new procurement in established markets such as Texas and Florida; it is also driving new procurement in markets like Pennsylvania and Oklahoma.

Although the Trump administration's tariffs on solar modules and other component parts have imposed additional costs, utility PV has continued to be cost-competitive with other generating sources in the U.S. Additionally, the number of states and utilities pledging renewable-energy or carbon-reduction targets continues to rise. Twenty-eight states have formally established clean-energy or carbon-reduction targets, 23 states have signed the U.S. Climate Alliance pledge to reduce economywide emissions by 28% by 2025, and eight governors have issued executive orders mandating increases in renewable or clean-energy targets in their states. While some of these state pledges are not legally binding, they have created demand and pressure for additional renewables in more state markets.

State solar PV installation rankings, 2019

	Rank			Installations (MW_{dc})		
State	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
California	1	1	1	2,596	3,236	3,124.6
Texas	4	2	2	718	1,009	1,381.2
Florida	3	4	3	766	865	1,377.1
Arizona	7	10	4	414	343	909.5
Georgia	23	39	5	75	18	880.6
North Carolina	2	3	6	1,246	935	864.5
South Carolina	8	13	7	392	151	510.5
New York	12	6	8	316	434	469.0
New Jersey	11	8	9	343	380	427.0
Nevada	9	5	10	386	550	403.6
Hawaii	17	18	11	Underlying data available in the full report		
Minnesota	6	7	12			
Massachusetts	5	9	13			
Colorado	20	11	14			
Connecticut	22	16	15			
Maryland	13	15	16			
Rhode Island	32	23	17			
Oregon	14	17	18			
Virginia	10	14	19			
Utah	21	26	20			
Illinois	42	33	21			
New Mexico	26	20	22			
Indiana	27	27	23			
Tennessee	25	32	24			
Pennsylvania	28	25	25			
Ohio	31	29	26			
Missouri	40	31	27			
Vermont	33	21	28			

	Rank			Installations (MWdc)		
State	2017	2018	2019	2017	2018	2019
Wisconsin	19	40	29	Underlying data available in the full report		
Washington	37	24	30			
Iowa	35	36	31			
Michigan	24	30	32			
Idaho	16	22	33			
New Hampshire	36	41	34			
Kansas	46	45	35			
Arkansas	45	12	36			
Other	29	37	37			
Washington DC	41	35	38			
Maine	44	34	39			
Nebraska	48	46	40			
Delaware	38	42	41			
Louisiana	43	38	42			
Mississippi	15	44	43			
Alaska	48	49	44			
Montana	30	48	45			
Kentucky	39	47	46			
Oklahoma	34	43	47			
West Virginia	48	50	48			
Wyoming	47	19	49			
Alabama	18	28	50			
South Dakota	48	52	51			
North Dakota	48	51	52			

Source: Wood Mackenzie

3. Market segment outlooks

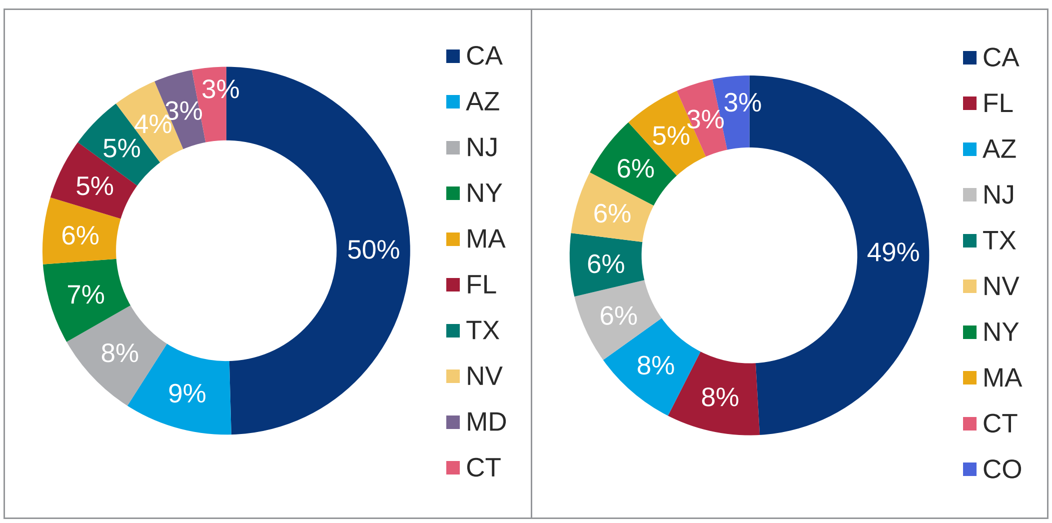
3.1. Residential PV

Key figures

- 2.8 GW_{dc} installed in 2019
- Up 15% from 2018

2019 was significant for residential solar for several reasons. Beyond seeing the highest number of total solar installations ever recorded, 2019 also brought a shakeup at the top of the residential solar rankings, reflecting the increased geographic diversity of residential solar adoption. For a national market that has long seen several Northeast states at the top of the rankings (that is, established residential PV markets that historically have benefited from high retail electricity rates and robust incentives), 2019 was the first year in which only one Northeast market (New Jersey) cracked the top five rankings. Instead, the top five state markets are a mixture of mature and emerging markets, with solid installation totals coming from established markets such as California and Arizona but also from newcomers Florida (No. 2) and Texas (No. 5).

Top 10 states, 2018 | Top 10 states, 2019



Source: Wood Mackenzie

While growth in these emerging markets is driven by increasingly attractive project economics, geographic diversification has also resulted in part from a slowdown in Northeast markets. In this region, higher levels of solar penetration and resulting steep customer-acquisition costs have slowed installation volumes since the peak installation years as the markets have grown past the segment of early-adopter consumers. These higher soft costs remain a long-term risk to the national market over the next few years, especially if the federal solar Investment Tax Credit steps down as scheduled under current law and so long as cost continues to be the foremost criterion in consumers' decision whether to adopt solar.

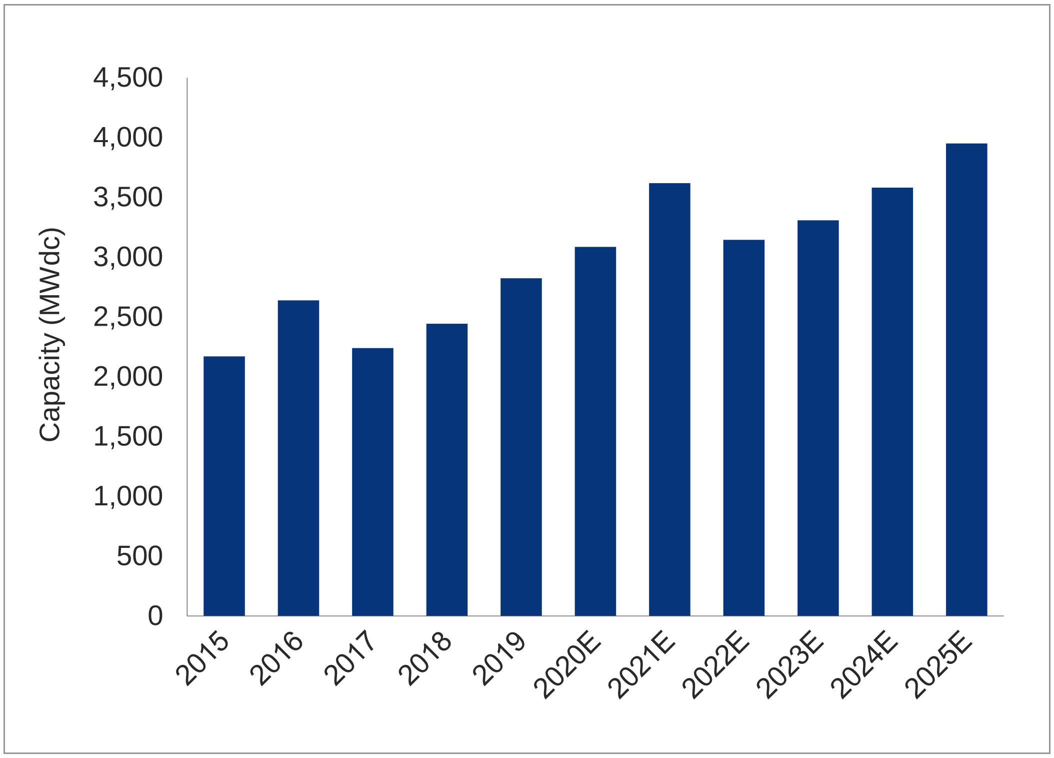
In 2019, California also demonstrated that residential solar adoption across the U.S. can be driven by other factors such as resiliency and concerns about climate change. In California, the combination of new-build home solar adoption (which began to gain steam in 2019 and is legally required for most single-family homes starting in 2020) and increasing disaffection with utilities due to public-safety power shutoffs (PSPS) is beginning to drive solar installations, increasingly paired with storage. While some of these drivers are now specific to California, national press coverage of PSPS and wildfires in the state, along with increased international emphasis on climate solutions, may encourage residential solar adoption across the country.

From 2020-2021, residential growth will range from 9% to 17% due to both emerging markets with strong resource fundamentals like Florida and Texas and markets where recent policy developments have increased our near-term forecasts. For example, Maryland's recent renewable portfolio standard increase, the removal of South Carolina's net metering cap and new incentive programs such as Illinois' Adjustable Block Program all provide upside potential to our residential forecasts over the next few years.

In the long term, the ITC step-down is expected to pull in demand across all markets before expiring in 2022 for customer-owned systems. After a soft 2022, modest growth will resume in 2023 and continue into 2024, based on economic fundamentals as the market adjusts to post-ITC market conditions. Long-term growth in a post-ITC world will be contingent on continued geographic diversification outside of established state markets (with markets including Pennsylvania and Colorado beginning to take off) as well as regulatory, technological and business-model innovation to improve product offerings in the solar-plus-storage space. Assuming modest growth on these fronts, residential solar growth is expected to reach high-single-digit percentages by the mid-2020s.

Residential installations and forecast, 2015-2025E

Forecasts do not account for impacts of the coronavirus outbreak



Source: Wood Mackenzie

3.2. Non-residential PV

- 2 GW_{dc} installed in 2019
- Down 7% from 2018

Non-residential installations were relatively weak in 2019 in California and Massachusetts, which continue to see declining volumes due to state-level policy reforms and interconnection delays that limit development opportunities. Meanwhile, Minnesota's community solar pipeline continues to diminish as grandfathered projects are built without pipeline replenishment for projects compensated under revised export credit rules. While this contributed to minor deployment declines in 2019, the year also marked the long-expected emergence of New York as a major community solar market. With more than 200 MW of community solar interconnected in 2019, New York helped offset installation declines in Minnesota. Going forward, the next wave of states with robust community solar mandates – New York, Maryland, Illinois and New Jersey – is expected to support growth and offset declines seen in the first major community solar market of Minnesota.

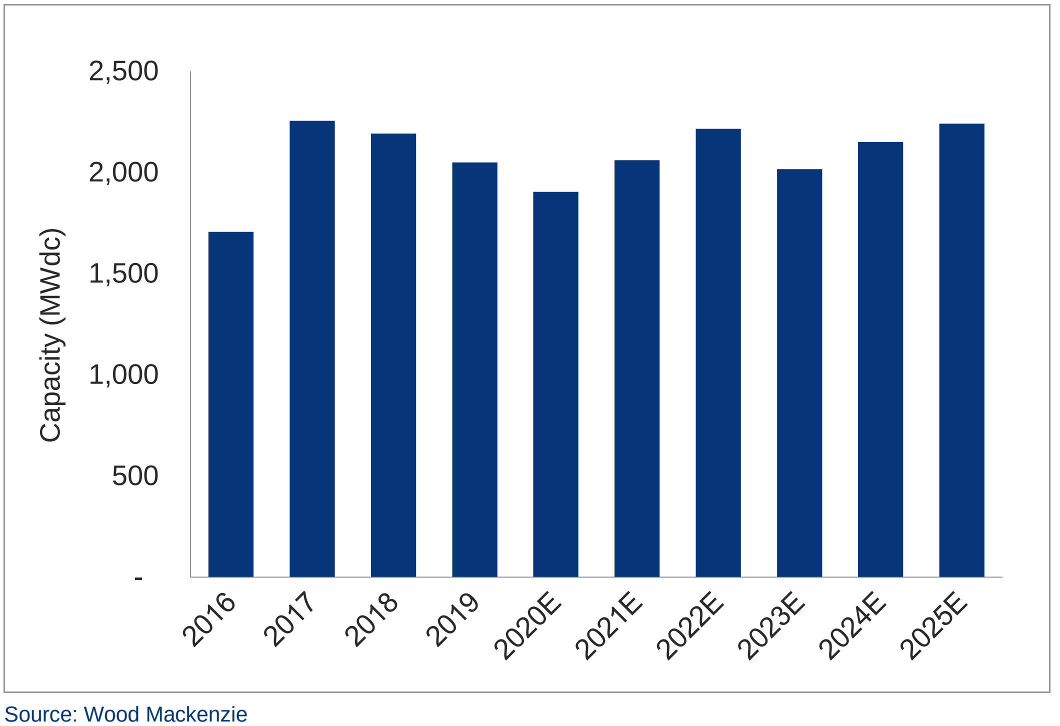
Recent policy developments in the Northeast will ultimately spur growth in our long-term outlook. New Jersey regulators have approved a transitional incentive program, slightly raising incentive values for community solar projects that appear to be workable across most market sub-segments. Meanwhile, New Jersey regulators have approved the first batch of community solar projects for the program's initial pilot year. That said, the approved projects will comprise only low- to moderate-income (LMI) customers, who have proven difficult to reach in other state markets. Accordingly, we have made downward revisions to our community solar forecasts.

In New York, significant revisions to the Value of Distributed Energy Resources tariff, in conjunction with the approval of consolidated billing for community solar, have bolstered our long-term forecasts for both commercial and community solar. Furthermore, Maryland and Maine both passed more aggressive renewable portfolio standard policies, which are expected to boost lagging renewable energy credit markets. Maine went even further, instituting a commercial solar tariff and a community solar program.

Increasing solar-plus-storage viability will also begin to support non-residential demand growth as policymakers and business leaders increasingly consider energy storage in their decision-making processes. By 2025, roughly 30% of total non-residential PV capacity will come from community solar, and one out of every four non-residential solar systems is expected to be paired with storage.

Non-residential installations and forecast, 2016-2025E

Forecasts do not account for impacts of the coronavirus outbreak



Source: Wood Mackenzie

3.3. Utility PV

- 8,402 MW_{dc} installed in 2019
- 4,380 MW_{dc} installed in Q4 2019, second-largest single quarter in history
- Utility PV pipeline currently totals 48.1 GW_{dc}

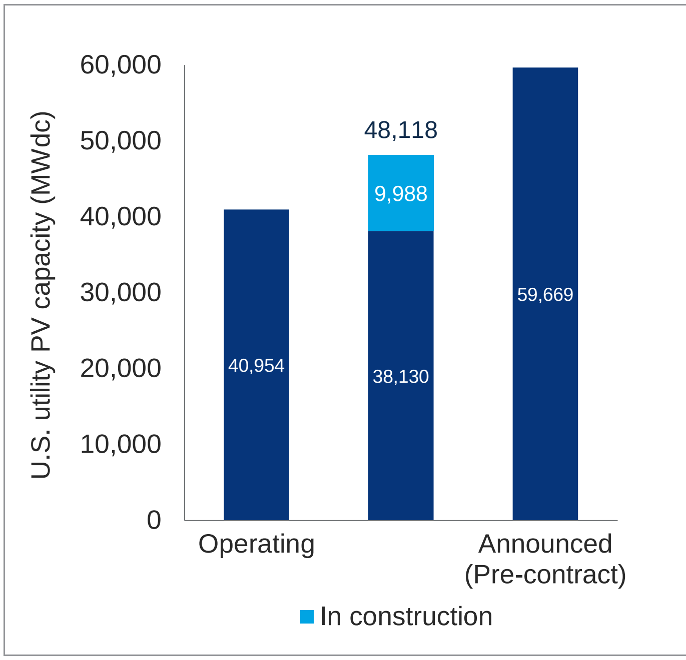
The utility PV sector served as the bedrock of the U.S. solar industry in 2019, accounting for 63% of annual capacity additions. The cumulative capacity of utility PV sits at 45.7 GWdc, representing 60% of all U.S. solar PV capacity. Over the next five years, we expect 82 GW of utility-scale solar to come online, nearly double the amount installed over the last 10 years. Annual procurement reached an all-time high in 2019 with 30.6 GWdc worth of new power-purchase agreements signed or announced. This has brought the cumulative contracted pipeline to a new record total of 48.1 GWdc. This surge was driven by developers and utilities safe-harboring as much capacity as possible to qualify for the full 30% ITC before it stepped down to 26% on 1 January 2020. We also continue to see a growing volume of utilities including solar in their long-term integrated resource plans and requests for proposals.

Voluntary procurement remains the largest driver of utility PV in the U.S., accounting for 57% of new procurement in 2019. However, there has been a rise in the number of projects driven by renewable portfolio standards, increasing from 10% in 2018 to 14% in 2019. Utility PV remains economically competitive against all other technologies in most state markets. As the federal Production Tax Credit for wind steps down, utility-scale solar will begin to make inroads in markets that have long been dominated by wind, while continuing to remain economically competitive with natural gas.

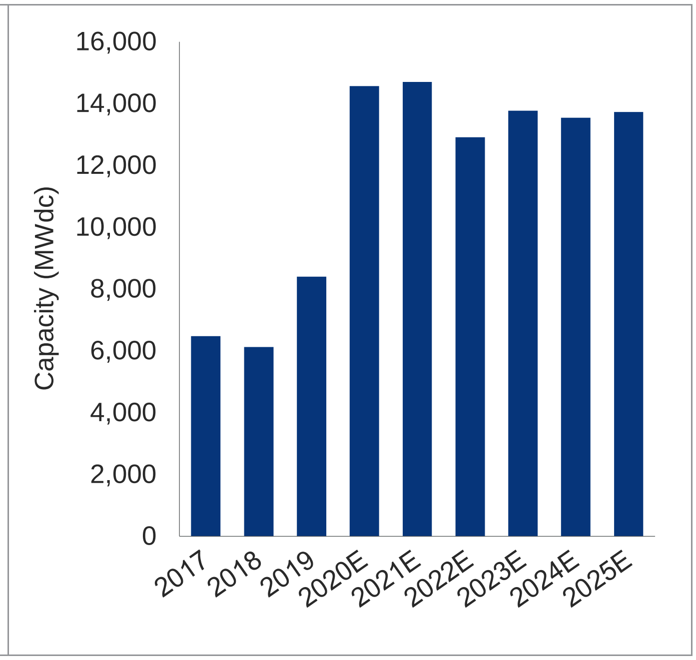
Corporate procurement of offsite utility PV drove 5.8 GWdc worth of new contracts in 2019, representing 19% of all procurement for the year. More than one-third of these projects are located in Texas, spurring rapid growth in the Lone Star State. Finally, several utilities have publicly announced their intention to procure projects with target commercial operation dates of 2024 or later; further details will help inform WoodMac's long-range forecasts.

Since last quarter, the five-year forecast has grown by 2.1 GWdc. The 2020 forecast grew by 0.5 GWdc due to increased confidence in near-term projects being completed in 2020 and the spillover of several 2019 projects into 2020. The 2021-2024 forecast saw a cumulative increase of 1.6 GWdc as more utilities begin procurement of utility-scale PV that was either previously outlined in resource planning documents or needed in order to fill capacity needs. With utility PV remaining economically competitive with other sources of generation, demand for utility PV remains strong through the decade, creating 13.7 GWdc of expected capacity additions in 2025.

Utility PV contracted pipeline, Q2 2017-Q2 2019



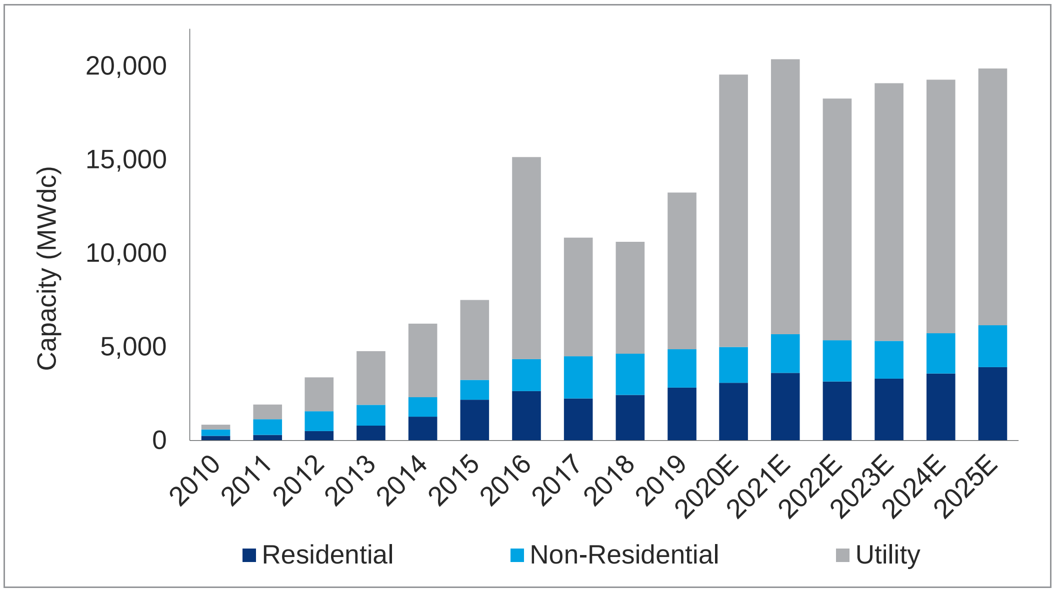
U.S. utility PV installations and forecast, 2016-2025E



Source: Wood Mackenzie
Note: Forecasts do not account for impacts of the coronavirus outbreak

U.S. PV installation forecast, 2010-2025E

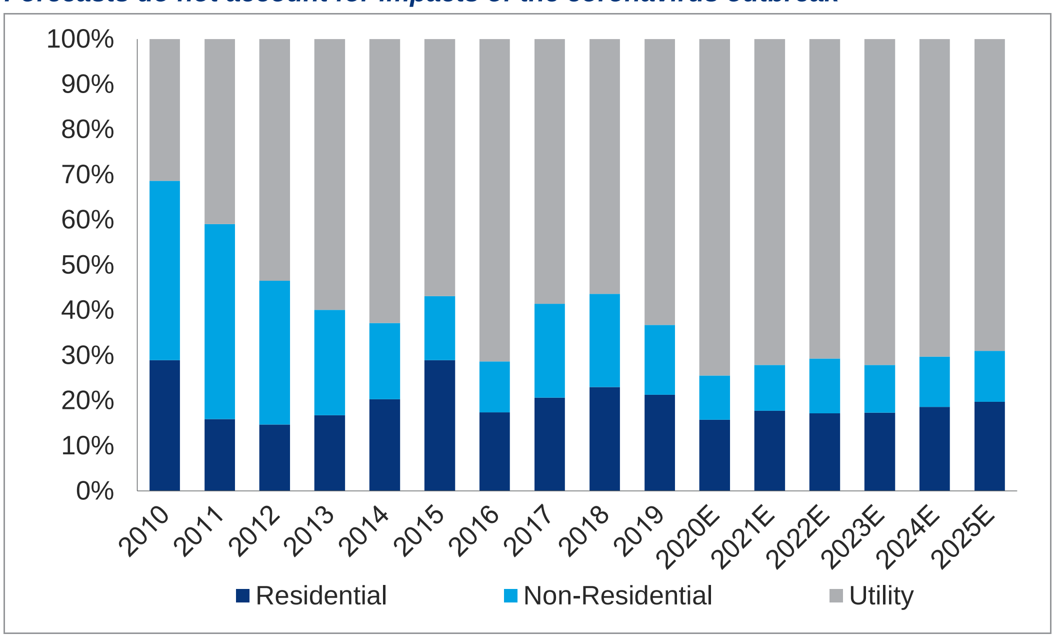
Forecasts do not account for impacts of the coronavirus outbreak



Source: Wood Mackenzie

U.S. PV installation forecast by segment, 2010-2025E

Forecasts do not account for impacts of the coronavirus outbreak

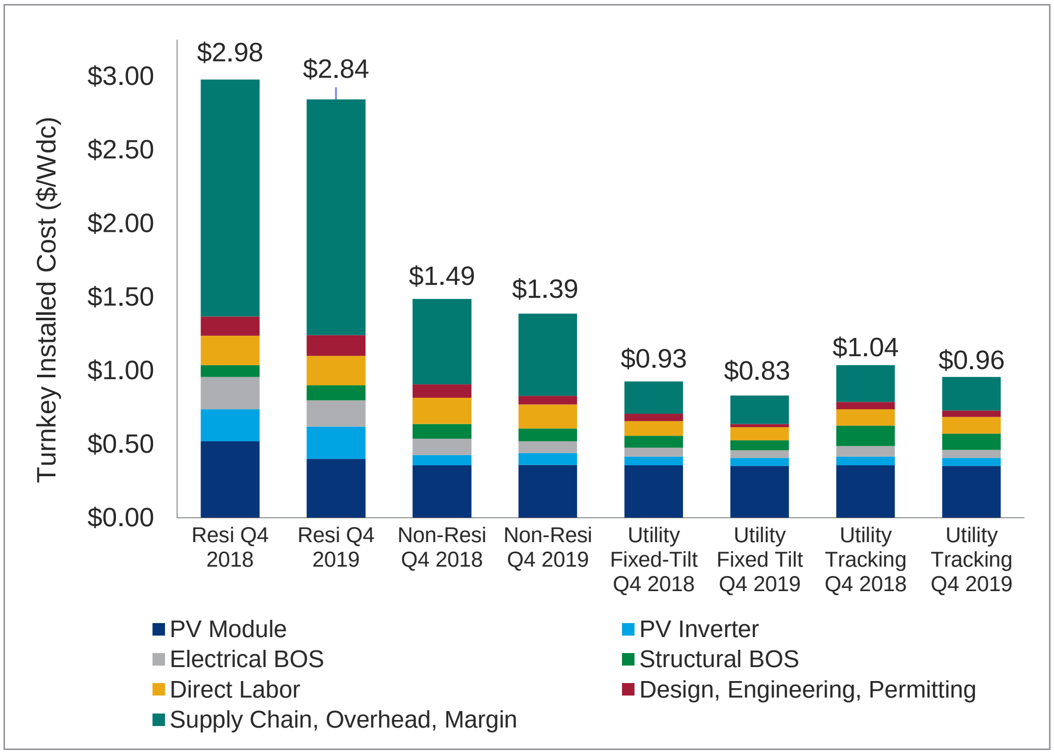


Source: Wood Mackenzie

4. National solar PV system pricing

We employ a bottom-up modeling methodology to capture, track and report national average PV system pricing for the major market segments. Our bottom-up methodology is based on tracked wholesale pricing of major solar components and data collected from multiple interviews with industry stakeholders. Due to increased demand for mono PERC solar modules, beginning with the 2019 Year in Review report, we will begin to report blended module prices for non-residential and utility market segments in addition to residential. This represents a weighted average of multi-silicon and mono PERC solar modules as opposed to pricing for multi-silicon modules only. Since the fourth quarter of 2019 is the first quarter with these new blended system prices, comparing Q4 2019 system prices to previous quarters for non-residential and utility will not be applicable. Mono PERC solar modules are more expensive than multi-silicon, and therefore the new blended module price methodology will yield higher system prices.

Modeled U.S. national average system costs by market segment, Q4 2018 and Q4 2019



Source: Wood Mackenzie

Note: Module prices in Q4 2018 reflect multi-silicon modules whereas module prices in Q4 2019 reflect a blended average of multi-silicon modules and mono PERC modules. Be wary of this when making comparisons in system prices. Detailed information about national system prices by market segment and component is available in the full report.

5. Component pricing

Starting in Q1 2019, the U.S. Solar Market Insight report series expanded its coverage to include pricing information on mono wafer, mono cells and mono modules, in addition to their multi counterparts.

In Q4 2019, global spot market pricing for all major components declined by various degrees from the previous quarter. Polysilicon prices decreased by 3.5% in Q4, resulting in commensurate mono and multi wafer price declines. Multi cell global spot prices continued to fall for the second quarter in a row, responding to shrinking global demand for the product. A similar trend holds true for multi modules. As new mono cell production capacities continued to come online in Q4, their prices held steady in the second half of 2019. Nevertheless, mono module prices fell by two cents in Q4, reflecting a healthy supply level.

In the U.S., multi-silicon module prices collapsed to 0.22/watt in Q4 2019, further proof that multi modules are essentially obsolete in the U.S. market. Mono PERC module prices finally broke the streak of price increases in Q4 2019, falling by two cents to $0.42/W for utility-scale projects.

In Q4 2019, the pricing for bifacial modules fluctuated due to international trade concerns. In December 2019, the United States Court of International Trade issued a temporary injunction, reversing the Office of the U.S. Trade Representative's October attempt to reimpose Section 201 tariffs on imported bifacial modules. As a result, the delivered prices for bifacial modules in the U.S. went up in October with the withdrawal of the tariff exemption; they were dropped again after the December temporary injunction. Without tariffs, bifacial modules were, on average, competitive in price with mono-facial modules.

Polysilicon, wafer, cell and module prices, Q4 2018-Q4 2019

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Polysilicon ($/kg) *	$ 9.9	$ 9.3	$ 8.9	$ 8.5	$ 8.2
Multi wafer ($/W) *	$ 0.06	$ 0.06	$ 0.06	$ 0.05	$ 0.05
Mono wafer ($/W) *	$ 0.08	$ 0.08	$ 0.09	$ 0.08	$ 0.08
Multi cell ($/W) *	$ 0.11	$ 0.11	$ 0.12	$ 0.11	$ 0.09
Mono cell ($/W) *	$ 0.13	$ 0.14	$ 0.12	$ 0.11	$ 0.11
Multi module ($/W) *	$ 0.23	$ 0.23	$ 0.23	$ 0.22	$ 0.20
Mono module ($/W) *	$ 0.27	$ 0.28	$ 0.28	$ 0.26	$ 0.24
U.S. multi module ($/W)	$ 0.34	$ 0.33	$0.32	$ 0.29	$0.22
U.S. mono PERC module ($/W)	$ 0.41	$ 0.40	$ 0.43	$ 0.44	$ 0.42

Source: Wood Mackenzie

**Global spot prices*

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7. Refer to the Application, Volume I, Appendix G, Figure 2, page 4.

a. Provide a copy of Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2019 Edition.

b. Explain whether the installed price is an "all in price."

c. Explain how the estimated cost of the current Madison county project compares to the prices in Figure 2.

RESPONSE:

a. A copy is attached.

b. The prices listed in Figure 2 are national median installed prices for host-owned PV systems. The report does not specify if it is an "all in price." Since they are for distributed systems, these prices are not directly comparable to the prices for utility-scale systems like Madison Solar.

WITNESS: David Loomis

Tracking the Sun

Pricing and Design Trends for Distributed Photovoltaic Systems in the United States

2019 Edition

Primary authors

Galen Barbose and Naïm Darghouth

See internal report cover for full list of contributing authors

September 2019

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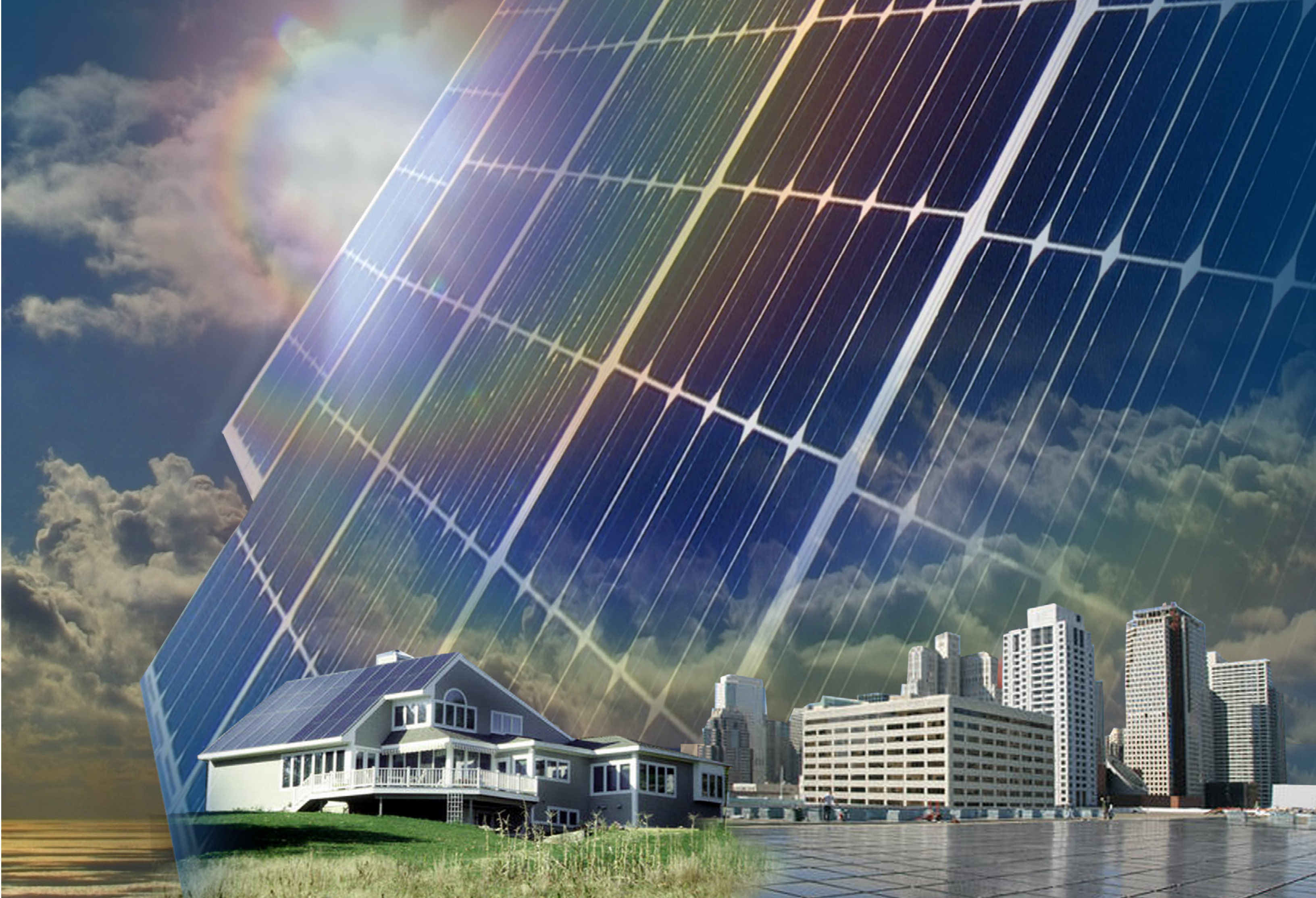

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Executive Summary

Lawrence Berkeley National Laboratory (LBNL)'s annual *Tracking the Sun* report summarizes installed prices and other trends among grid-connected, distributed solar photovoltaic (PV) systems in the United States.[1] This edition focuses on systems installed through year-end 2018, with preliminary trends for the first half of 2019. As in years past, the primary emphasis is on describing changes in installed prices over time and variation across projects. This year's report also includes an expanded discussion of other key technology and market trends, along with several other new features, as noted in the text box below.

Trends in this report derive from project-level data reported primarily to state agencies and utilities that administer PV incentives, renewable energy credit (REC) registration, or interconnection processes. In total, data were collected and cleaned for 1.6 million individual PV systems, representing 81% of all U.S. distributed PV systems installed through 2018. The analysis of installed prices is based on the subset of roughly 680,000 host-owned systems with available installed price data. A public version of the full dataset is available at trackingthesun.lbl.gov.

Numerical results are denoted in direct current (DC) Watts (W) and real 2018 dollars. Non-residential systems are segmented into small vs. large non-residential, based on a cut-off of 100 kW.

New Features in This Year's *Tracking the Sun*

- *Expanded Discussion of Project Characteristics*. This year's report includes additional trends related to distributed PV orientation, inverter loading ratios, and solar-plus-storage.
- *Focus on Host-Owned Systems for Installed Pricing Analysis*. In order to simplify the analysis and discussion, the report now excludes third-party owned systems from its analysis of installed pricing trends, though those systems are included when characterizing broader technology and market trends.
- *Multi-Variate Regression Analysis*. The report now includes an econometric model of installed pricing variation across residential systems installed in 2018, supplementing the descriptive analysis.

Distributed PV Project Characteristics. Key technology and market trends based on the full dataset compiled for this report are as follows.

- PV systems continue to grow in size, with median sizes in 2018 reaching 6.4 kW for residential systems and 47 kW for non-residential systems. Sizes also vary considerably within each sector, particularly for non-residential systems, for which 20% were larger than 200 kW in 2018.
- Module efficiencies continue to grow over time, with a median module efficiency of 18.4% across all systems in the sample in 2018, a full percentage point increase from the prior year.
- Module-level power electronics—either microinverters or DC optimizers—have continued to gain share across the sample, representing 85% of residential systems, 65% of small non-residential systems, and 22% of large non-residential systems installed in 2018.
- Inverter-loading ratios (ILRs, the ratio of module-to-inverter nameplate ratings) have generally grown over time, and are higher for non-residential systems than for residential

[1] In the context of this report "distributed PV" includes both residential as well as non-residential rooftop systems and ground-mounted systems smaller than 5 MW_{AC} (or roughly 7 MW_{DC}). An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector, which consists of ground-mounted PV systems larger than 5 MW_{AC}.

systems. In 2018, the median ILR was 1.11 for residential systems with string inverters and 1.16 for those microinverters, while large non-residential systems had a median ILR of 1.24.

- Roughly half (52%) of all large non-residential systems in the 2018 sample are ground-mounted, while 7% have tracking. In comparison, 17% of small non-residential systems and just 3% of residential systems are ground-mounted, and negligible shares have tracking.
- Panel orientation has become more varied over time, with 57% of systems installed in 2018 facing the south, 23% to the west, and most of the remainder to the east.
- A small but increasing share of distributed PV projects are paired with battery storage, typically ranging from 1-5% in 2018 across states in our dataset, though much higher penetrations occurred in Hawaii and in a number of individual utility service territories.
- Third-party ownership (TPO) has declined in recent years, dropping to 38% of residential, 14% of small non-residential, and 34% of large non-residential systems in the 2018 sample.
- Tax-exempt customers—consisting of schools, government, and nonprofit organizations—make up a disproportionately large share (roughly 20%) of all 2018 non-residential systems.

Temporal Trends in Median Installed Prices. The analysis of installed pricing trends in this report focuses primarily on host-owned systems. Key trends in *median* prices, prior to receipt of any incentives, are as follows.

- National median installed prices in 2018 were \$3.7/W for residential, \$3.0/W for small non-residential, and \$2.4/W for large non-residential systems. Other cost and pricing benchmarks tend to be lower than these national median values, and instead align better with 20th percentile values (see Text Box 5 in the main body for further discussion of these issues).
- Over the last full year of the analysis period, national median prices fell by \$0.2/W (5%) for residential, by \$0.2/W (7%) for small non-residential, and by \$0.1/W (5%) for large non-residential systems. Those \$/W declines are in-line with trends over the past five years.
- Over the longer-term, since 2000, installed prices have fallen by \$0.5/W per year, on average, encompassing a period of particularly rapid declines (2008-2012) when global module prices rapidly fell. In many states, the long-term drop in (pre-incentive) installed prices has been substantially offset by a corresponding drop in rebates or other incentives.
- Preliminary and partial data for the first half of 2019 show roughly a \$0.1/W drop in median installed prices compared to the first half of 2018, though no observable drop relative to the second half of 2018. Those trends are based on a subset of states, consisting of larger markets, where price declines have recently slowed compared to other states.
- Installed price declines reflect both hardware and soft-cost reductions. Since 2014, following the steep drop in global module prices, roughly 64% of the total decline in residential installed prices is associated with a drop in module and inverter price, while the remaining 36% is due to a drop in soft costs and other balance-of-systems (BoS) costs. For non-residential systems, a slightly higher percentage of total installed price declines is attributable to BoS and soft costs.

Variation in Installed Prices. This report highlights the widespread variability in pricing across projects and explores some of the drivers for that variability, focusing primarily on systems installed in 2018. The exploration of pricing drivers includes both basic descriptive comparisons as well as a more formal econometric analysis. Key findings include the following.

- Installed prices in 2018 ranged from \$3.1-4.5/W for residential systems (based on the 20th and 80th percentile levels), from \$2.4-4.0/W for small non-residential systems, and from \$1.8-3.3/W for large non-residential systems.
- Installed prices within each customer segment vary substantially depending on system size, with median prices ranging from \$3.3-4.3/W for residential, from \$2.7-3.4/W for small non-residential, and from \$2.0-3.6/W for large non-residential systems, depending on size.
- Installed prices also vary widely across states, with state-level median prices ranging from \$2.8-4.4/W for residential, \$2.5-3.7/W for small non-residential, and \$1.7-2.5/W for large non-residential systems.
- Across the top-100 residential installers in 2018, median prices for each individual installer generally ranged from \$3.0-5.0/W, with most below \$4.0/W.
- Median prices are notably higher for systems using premium efficiency modules (>20%) and for systems with microinverters or DC optimizers. Comparisons between residential retrofits and new construction, and comparisons based on mounting configuration, are both less revealing, likely due to relatively small underlying sample sizes.
- The multi-variate regression analysis, which focuses on host-owned residential systems installed in 2018, shows relatively substantial effects associated with system size (a \$0.8/W range between 20th and 80th percentile system sizes) and with other system-level factors, including those related to module efficiency (+\$0.2/W for systems with premium efficiency modules), inverter type (+\$0.2/W for systems with either microinverter or DC-optimizers), ground-mounting (+\$0.3/W), and new construction (-\$0.5/W).
- In comparison, the regression analysis found relatively small effects for various market- and installer-related drivers—including variables related to market size (a \$0.2/W range between the 20th to 80th percentile values for market size), market concentration (a \$0.1/W range), household density (a \$0.2/W range), average household income (no effect), and installer experience (no effect).
- After controlling for various system-, market-, and installer-level variables, the regression analysis still found substantial residual pricing differences across states (a \$1.5/W range), indicating that other, unobserved factors significantly impact installed prices at the state- or local-levels.

1. Introduction

The market for solar photovoltaics (PV) in the United States has been driven in part by various forms of policy support for solar and renewable energy. A central goal of many of these policies has been to facilitate and encourage cost reductions over time. The U.S. Department of Energy's Solar Energy Technologies Office, for example, has sought to reduce costs to $1.50/W for residential systems and $1.25/W for commercial systems by 2020, and by an additional 50% by 2030.[2] Others have argued that even deeper cost reductions may be needed over the longer-term, given the declining value of solar with increasing grid penetration (Sivaram and Kann 2016). As public and private investments in these efforts have grown, so too has the need for comprehensive and reliable data on the cost and price of PV systems, in order to track progress towards cost reduction targets, gauge the efficacy of existing programs, and identify opportunities for further cost reduction. Such data are also instrumental to cultivating informed consumers and competitive markets, which are themselves essential to achieving long-term cost reductions.

To address these varied needs, Lawrence Berkeley National Laboratory (LBNL) initiated the annual *Tracking the Sun* report series to summarize historical trends in the installed price of grid-connected, distributed PV systems in the United States.[3] It is produced in conjunction with several other ongoing National Lab research products that also address PV system costs and pricing, including a companion LBNL report focused on trends in the utility-scale solar market (see Text Box 1).

This edition of *Tracking the Sun* describes installed price trends for projects installed through 2018, with preliminary data for the first half of 2019. The report is intended to provide an overview of both long-term and more-recent trends, highlighting a number of key drivers underlying these trends. The report also discusses in depth observed *variability* in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics. The analysis of installed pricing variation includes both a descriptive component (comparing median prices across different types of systems, installers, and markets) as well as a multi-variate regression analysis that controls for correlations among individual pricing drivers. Finally, beyond its primary focus on installed prices, the report also describes a variety of other technology and market trends for distributed PV.

Text Box 1. Related National Lab Research

Tracking the Sun is produced in conjunction with several related and ongoing research activities:

- *Utility-Scale Solar* is a separate annual report series produced by LBNL that focuses on utility-scale solar (ground-mounted projects larger than 5 MW_{AC}) and includes trends and analysis related to project cost, performance, and pricing.
- *PV System Cost Benchmarks* developed by NREL researchers are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (for example, see Fu et al. 2018).
- *Other Derivative Works* that rely on the Tracking the Sun dataset include in-depth statistical analyses of PV pricing dynamics, solar-adopter demographics, impacts of solar on property value, and other topics. These and other solar energy publications are available here.

[2] The 2020 cost targets are denominated in real 2010 dollars.
[3] In the context of this report "distributed PV" includes both residential as well as non-residential rooftop systems and ground-mounted systems smaller than 5 MW_{AC} (or roughly 7 MW_{DC}).

The trends presented in this report are based primarily on project-level data provided by state agencies, utilities, and other entities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. The full dataset underlying this year's report consists of more than 1.6 million grid-connected, distributed PV systems installed through year-end 2018, representing roughly 81% of the total U.S. market. A public version of this data file is available at trackingthesun.lbl.gov. LBNL applies a substantial degree of quality control and undertakes numerous steps to clean these data. The analysis of installed price trends is based on the subset of approximately 680,000 host-owned systems for which installed price data are available.

Essential to note at the outset are several important aspects of the installed price data described within this report. First, as noted above, the analysis of installed prices focuses solely on host-owned systems and excludes third-party owned (TPO) systems, for reasons discussed in the main body of the report. Installed prices for host-owned systems represent the up-front price paid by the host customer, prior to receipt of incentives. These values may differ from the underlying costs borne by the developer or installer, for a variety of reasons. The data are also self-reported, and therefore may be subject to inconsistent reporting practices (e.g., in terms of the scope of the underlying items embedded within the reported price or whether the administrator validates reported prices against invoices). Furthermore, these data are historical, and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects. Last but not least, it is important to acknowledge that installed prices are but one aspect of evaluating the customer economics of distributed PV; a full evaluation also requires consideration of ongoing operating costs as well as system performance over time.

The remainder of the report is organized as follows. Section 2 summarizes the data sources, key methodological details, and the sample size relative to the total U.S. and state distributed PV markets. Section 3 describes key characteristics of the full data sample, including system size trends, third-party ownership, customer segmentation, module efficiencies, use of module-level power electronics, inverter loading ratios, panel orientation, the prevalence of ground-mounting and tracking, and pairing of storage with distributed PV. Section 4 presents an overview of long-term, installed-price trends, focusing on median values drawn from the large underlying data sample. The section illustrates and discusses a number of the broad drivers for those historical installed-price trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. The section also compares median installed prices for systems installed in 2018 to a variety of other recent U.S. benchmarks. Section 5 describes the variability in installed prices within the dataset, and explores installed pricing differences across projects, including those related to: system size, state, installer, module efficiency, inverter type, residential new construction vs. retrofit, for-profit commercial vs. tax-exempt site host, and mounting configuration. That section also includes a multi-variate regression analysis, focusing on residential systems installed in 2018, which controls for correlations among various pricing drivers in order to better isolate their individual effects. Finally, Section 6 offers brief conclusions. The Appendix provides further details on data sources and the data cleaning process, as well as additional details on the regression analysis.

Additional supplementary materials are available online at http://trackingthesun.lbl.gov/, including a public version of the Tracking the Sun dataset, summary data tables containing the numerical values plotted in the figures throughout the report, a slide deck summary of the report, and a webinar recording.

2. Data Sources, Methods, and Market Coverage

The trends presented in this report derive from data on individual distributed PV systems. This section describes the underlying data sources and the procedures used to standardize and clean the data, with further information provided in the Appendix. The section then describes the sample size over time and by market segment, comparing the data sample to the overall U.S. PV market and to individual state markets, highlighting any significant gaps in market coverage.

Data Sources

The data for this report are sourced primarily from state agencies, utilities, and other organizations that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. In total, 67 entities spanning 30 states contributed data to this report (see Table A-1 in the Appendix). These data sources have evolved over time, particularly as incentive programs in a number of states have expired. In these instances, data collection has often continued to occur through the other types of administrative processes noted above. In some cases, gaps in data collection have occurred, such as in California, as discussed further below.

Data Standardization and Cleaning

Various steps were taken to clean and standardize the raw data. First, all systems missing data for system size or installation date, as well as any utility-scale PV systems or duplicate systems contained in multiple datasets, were removed from the raw sample. The remaining data were then cleaned by correcting text fields with obvious errors and by standardizing the spelling of installer names and module and inverter manufacturers and model names. Using the cleaned module and inverter names, equipment spec sheet data were integrated into the dataset, including data on module efficiency and technology type and inverter power rating and technology type. Each system was also categorized as either residential, small non-residential, or large non-residential, per the definitions described in Text Box 2. Finally, all price and incentive data were converted to real 2018 dollars (2018$), and if necessary system size data were converted to direct-current (DC) nameplate capacity under standard test conditions (STC). The resulting dataset, following these initial steps, is referred to hereafter as the ***full sample*** and is the basis for the public data file (which differs only in the exclusion of confidential or sensitive data).

For the purpose of analyzing installed prices, several other categories of systems were then removed from the data. Most significantly, all TPO were removed, as prices

Text Box 2. Customer Segment Definitions

This report distinguishes among three customer segments:

***Residential**:* Includes single-family residences and, depending on the conventions of the data provider, may also include multi-family housing.

Small Non-Residential: Includes all non-residential systems up to 100 kW_{DC}.

Large Non-Residential: Includes non-residential systems larger than 100 kW_{DC}, with no upper size limit for rooftop systems and a cap of 5,000 kW_{AC} (roughly 7,000 kW_{DC}) for ground-mounted systems.

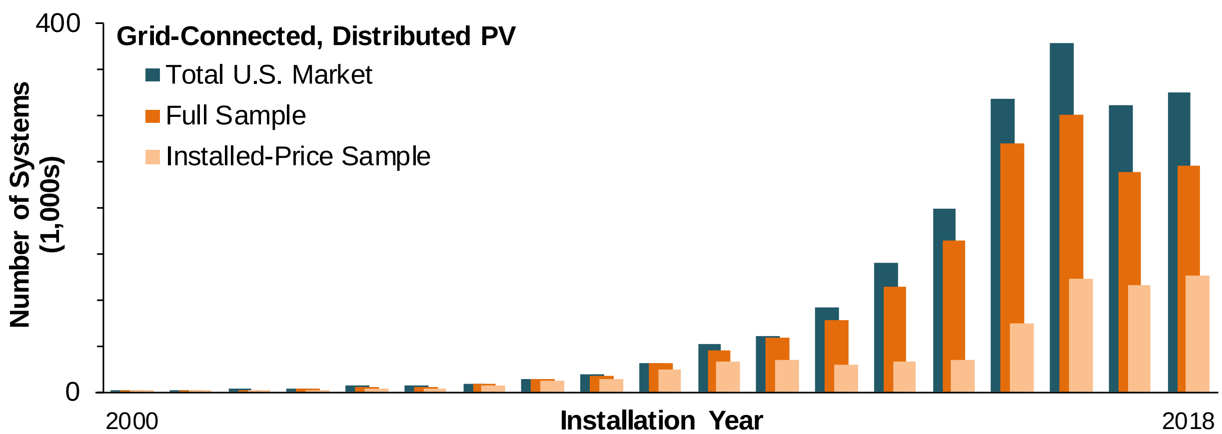
Ground-mounted systems larger than 5,000 kW_{AC} are considered **utility-scale** and are addressed separately in Berkeley Lab's companion *Utility-Scale Solar* annual report. Note that these various customer segment definitions may differ from those used by other organizations, and thus some care must be taken in comparisons.

reported for those systems cannot be meaningfully compared to those of host-owned systems (though, for reference, Text Box 3, presented later in the report, compares installed prices reported for TPO and host-owned systems). Host-owned systems installed by SolarCity/Tesla were also removed, as prices reported for those systems appear to represent appraised values, rather than transaction prices. Also excluded from the installed-price analysis are systems missing installed price data, systems with battery-back up, self-installed systems, and systems with prices less than $1/W or greater than $20/W (assumed data entry errors). The resulting dataset, after these various additional exclusions are applied, is denoted hereafter as the ***installed-price sample*** and is the basis for all installed price trends presented in the report, unless otherwise indicated. Further details on these steps and on other elements of the data cleaning process are described in Appendix B.

Sample Size and Market Coverage

The ***full sample*** includes the majority of all U.S. grid-connected residential and non-residential PV systems. In total, it consists of more than 1.6 million individual PV systems installed through year-end 2018, including roughly 250,000 systems installed in 2018 (Figure 1 and Table 1). This represents 81% of all U.S. residential and non-residential systems installed cumulatively through 2018 and 76% of installations in 2018. As discussed further below, coverage within the largest state markets is relatively high, and much of the sample gap is associated with smaller and mid-sized state markets either missing or under-represented in the sample.

The ***installed-price sample*** consists of roughly 680,000 systems installed through year-end 2018 and 120,000 systems installed in 2018. The gap between the full sample and the installed-price sample consists primarily of TPO systems (approximately 630,000 systems) and systems missing installed price data (approximately 270,000 systems). The latter includes all systems from several states for which installed price data are wholly unavailable (as noted below), as well as a sizeable number of California systems installed from 2013 through 2015, during which time the collection of installed pricing data lapsed as the state's incentive program was winding down and the new data collection process had not yet been fully implemented. As shown in Figure 1, the gap between the full sample and installed-price sample has narrowed in recent years, due to increased availability of installed price data for California and the diminishing market share of TPO systems.



Notes: Total U.S. distributed PV installations are based on data from IREC (Sherwood 2016) for all years through 2010 and from Wood Mackenzie and SEIA (2019) for each year thereafter.

Figure 1. Comparison of the Data Sample to the Total U.S. Distributed PV Market

Table 1. Full Sample and Installed-Price Sample by Installation Year and Market Segment

Installation Year	Full Sample (No. of Systems)				Installed-Price Sample (No. of Systems)			
	Residential	Small Non-Res.	Large Non-Res.	***Total***	Residential	Small Non-Res.	Large Non-Res.	***Total***
1998	25	1	1	***27***	8	0	0	***8***
1999	210	11	1	***222***	111	2	0	***113***
2000	201	11	1	***213***	115	8	0	***123***
2001	1,243	40	5	***1,288***	832	18	0	***850***
2002	2,294	163	27	***2,484***	1,554	80	3	***1,637***
2003	3,070	265	45	***3,380***	2,513	169	16	***2,698***
2004	5,189	434	38	***5,661***	4,451	297	24	***4,772***
2005	5,371	454	81	***5,906***	4,532	296	56	***4,884***
2006	8,958	549	102	***9,609***	7,852	357	74	***8,283***
2007	13,612	876	154	***14,642***	11,255	592	89	***11,936***
2008	15,843	1,552	378	***17,773***	12,344	1,176	178	***13,698***
2009	28,792	2,077	353	***31,222***	22,360	1,687	213	***24,260***
2010	41,188	3,565	713	***45,466***	30,657	2,883	438	***33,978***
2011	53,137	5,290	1,638	***60,065***	30,193	3,518	795	***34,506***
2012	71,819	5,423	1,741	***78,983***	25,946	3,414	827	***30,187***
2013	108,847	4,043	1,458	***114,348***	30,810	2,049	632	***33,491***
2014	159,394	4,763	1,375	***165,532***	33,256	1,716	646	***35,618***
2015	263,205	4,792	1,512	***269,509***	71,558	2,251	646	***74,455***
2016	293,410	5,748	2,311	***301,469***	118,625	3,491	1,199	***123,315***
2017	231,405	4,653	2,552	***238,610***	110,995	3,323	1,357	***115,675***
2018	239,477	4,390	2,210	***246,077***	122,404	3,151	1,145	***126,700***
Total	***1,546,690***	***49,100***	***16,696***	***1,612,486***	***642,371***	***30,478***	***8,338***	***681,187***

Notes: Text Box 2 for an explanation of the three customer segments used in this table and throughout the report.

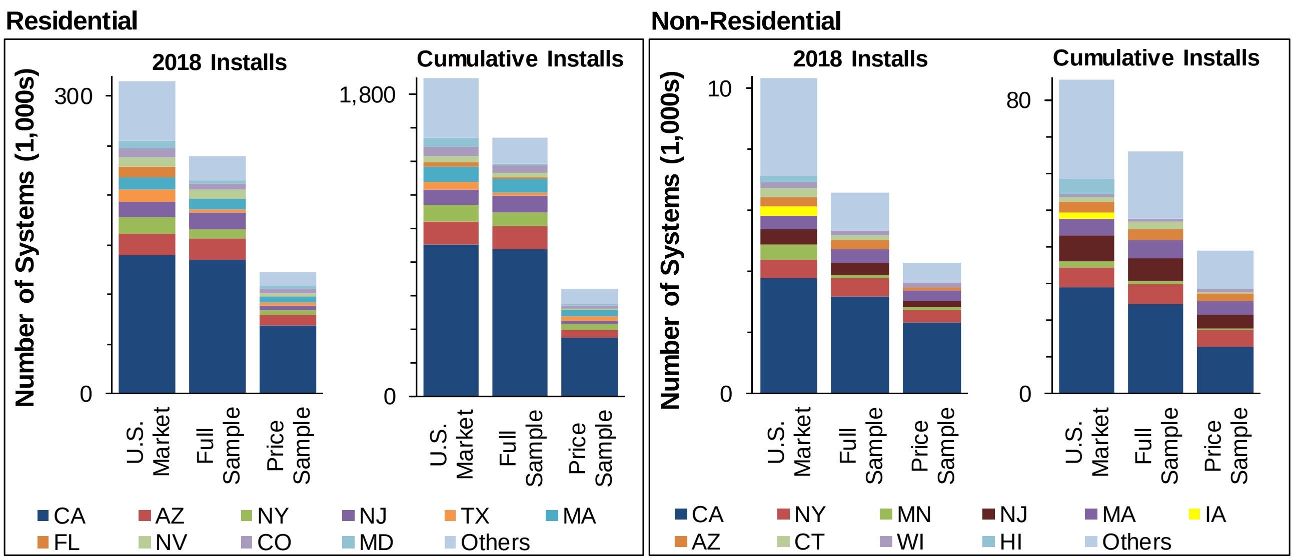
The full sample includes systems installed across 30 states, winnowed down to 26 states in the installed-price sample, which excludes four states (DC, KS, MO, and OH) wholly lacking installed price data. Though the sample has fairly broad geographic representation, it is nevertheless concentrated in a relatively small number of state markets, consistent with the broader U.S. market. This is illustrated in Figure 2, which shows the state-level market coverage and geographic distribution of the data sample, compared to the overall U.S. distributed PV market. Further details on sample sizes by state and data provider are also contained in Table B-1 in the Appendix.

California is, by far, the largest state in the sample—in terms of both 2018 installations and cumulative installations, for both residential and non-residential systems. Arizona, Massachusetts, New Jersey, and New York make up the bulk of the remaining sample, for both the residential and non-residential sectors. These five states comprise a disproportionately large share of the sample, relative to their share of the overall U.S. market, which may have implications for the aggregate, national trends presented in this report, as discussed in later sections.

As a general matter, coverage within most of the major state markets is relatively strong, though several notable gaps do exist. Within the residential sector, the biggest data gaps are in Texas, Florida, and Maryland; while the biggest data gaps in the non-residential sample are for Minnesota, Iowa, and Hawaii.[4] Outside of those states, however, the data sample includes at least 60%, and in

[4] For Texas and Florida, the data come mostly from large municipal utilities, but almost no data were provided by those states' investor-owned utilities. In Maryland, the data come from the state's rebate program, which has a limited annual budget and is open only to host-owned systems. For Minnesota, much of the recent growth in the non-residential

most cases more than 80%, of systems installed in each of the top-10 residential and non-residential states in 2018. More generally, where sample coverage tends to be weakest is among smaller state markets (denoted as "Others" in the figure) that are either missing or under-represented in the sample. As also evident in the figure, coverage within the non-residential sector is somewhat lower than for residential systems; this partly reflects the more diffuse nature of the non-residential market, as well as the fact that non-residential systems are more likely to be installed outside of incentive programs, such as those that contribute data to this report.



Notes: Data for the total U.S. market are from Wood Mackenzie and SEIA (2019). The figure identifies the top-10 states in each customer segment, based on total U.S. market installations in 2018. The figure consolidates non-residential systems rather than distinguishing between the two size classes used elsewhere in the report, as U.S. market data are available only for non-residential systems as a whole. See Table B-1 in the appendix for additional details, including sample sizes for individual states included in "Others".

Figure 2. State-Level Market Coverage in the Data Sample

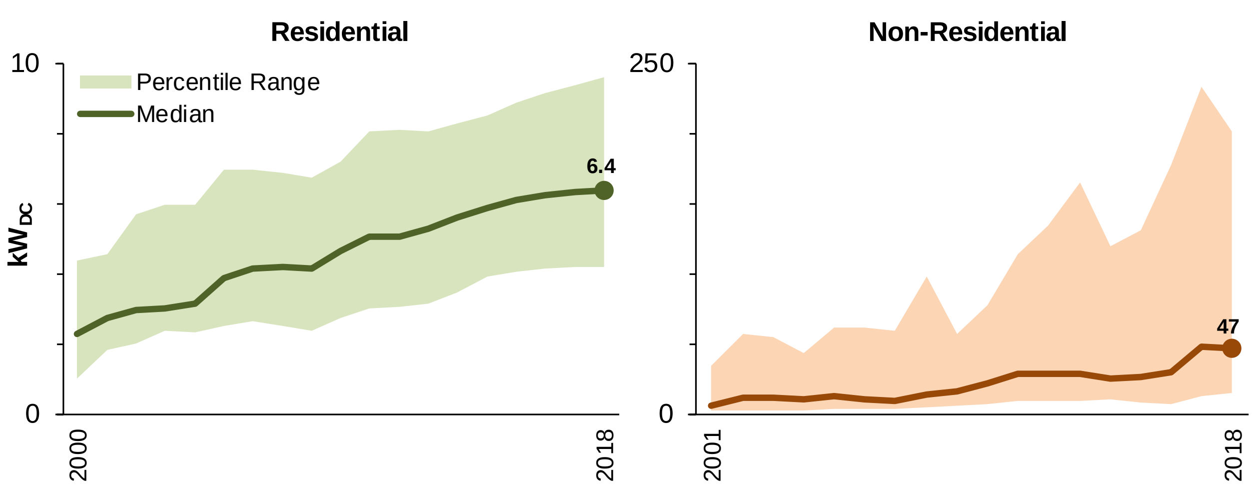
segment has been community solar, which is largely absent from the data collected for this report, and Iowa and Hawaii are both wholly missing from this report.

3. PV System Characteristics

Characteristics of the data sample help to illustrate trends within the broader U.S. distributed PV market, and provide context for understanding installed price trends presented later in this report. To those ends, we describe below key characteristics of the data sample, including: the evolution of system sizes over time, module efficiencies, the use of module-level power electronics, inverter loading ratios (ILRs), the prevalence of ground-mounting and tracking equipment, system orientation, the prevalence of solar-plus-storage, the distribution between host-owned and TPO systems, and the composition of non-residential site hosts. These trends are based on the *full data sample*, in contrast to the installed-price trends discussed later, which are based on the smaller *installed-price sample*, as described in Section 2.

System Size

As shown in Figure 3, both residential and non-residential system sizes have grown substantially over time. In the residential sector, median system sizes grew from 2.4 kW in 2000 to 6.4 kW in 2018. Those trends partly reflect increasing module efficiencies, as many residential systems are space-constrained based on available roof area. In the non-residential sector, median system sizes grew from 7 kW to 47 kW over the period shown, though the more pronounced trend is the growth at the upper end of the size spectrum, as indicated by the widening percentile bands in Figure 3. At the 80th percentile level, non-residential system sizes grew from 35 kW to 201 kW. Large non-residential systems, both rooftop and ground-mounted, have become increasingly prevalent as a broader set of non-residential customers become comfortable with the technology and as developers and investors seek out projects offering higher returns. It is partly because of this wide range in project sizes that this report elsewhere distinguishes between small and large non-residential systems.[5]



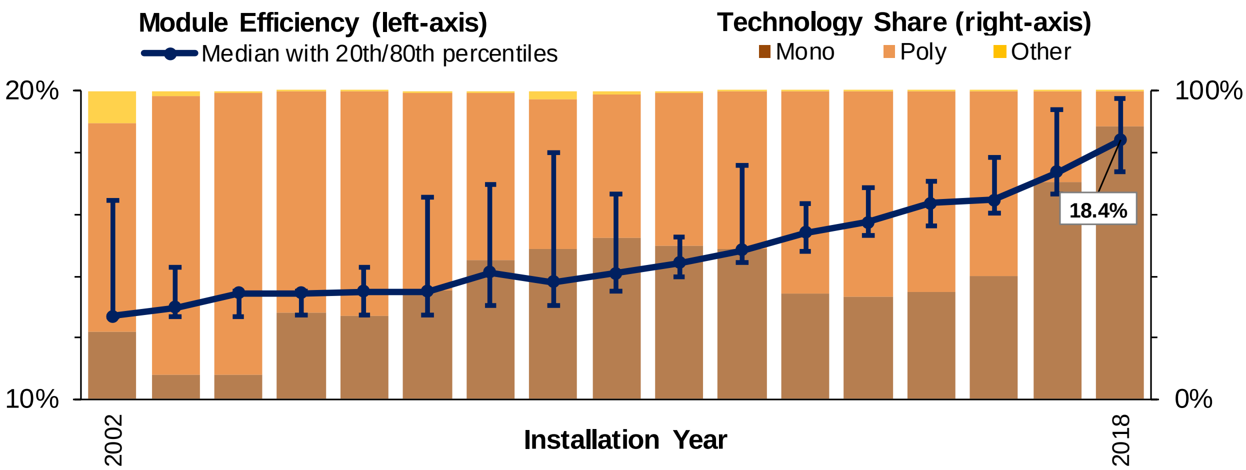
Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year. Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 3. System Size over Time

[5] As noted previously, ground-mounted systems larger than 5 MW_{AC}, or roughly 7 MW_{DC}, are covered in LBNL's companion *Utility-Scale Solar* report.

Module Efficiencies

Module efficiency levels have risen considerably over time, from a median of 12.7% in 2002 to 18.4% in 2018, as shown in Figure 4. These gains have been particularly pronounced over the past several years, with median efficiencies climbing by roughly one percentage point in both 2017 and again in 2018. Those recent gains reflect a correspondingly sharp increase in the share of mono-crystalline modules, from 40% of the sample in 2016 to almost 90% in 2018, as well as a steady increase in the use of passivated emitter rear-cell (PERC) technology. Over the long term, efficiencies for both mono- and poly-crystalline technologies have risen substantially, as manufacturing processes and cell architectures have steadily improved.



Notes: Median values prior to 2002 are omitted due to small sample sizes.

Figure 4. Module Efficiency Trends over Time

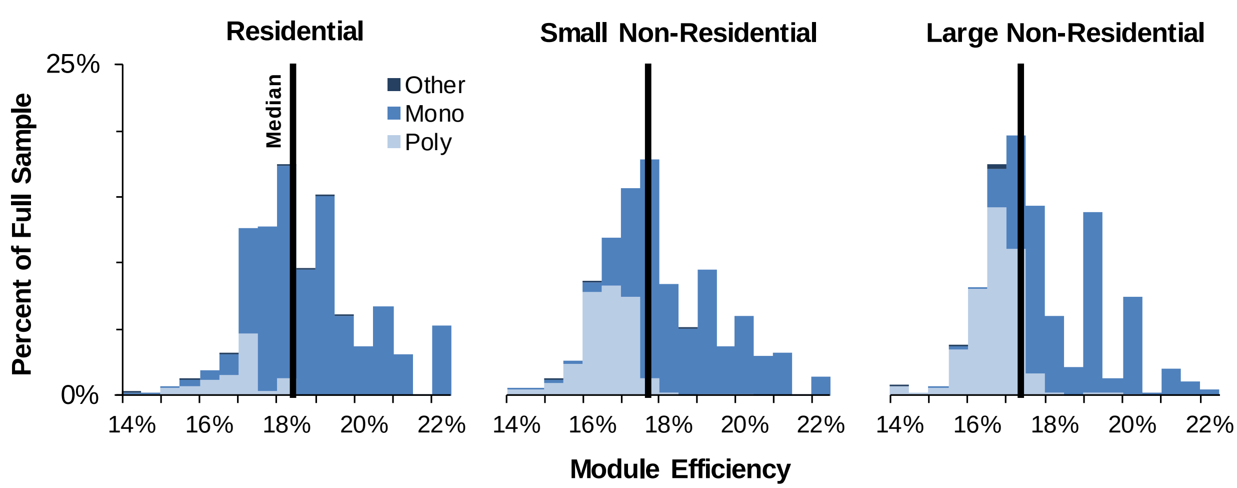


Figure 5. Module Efficiency Distributions for Systems Installed in 2018

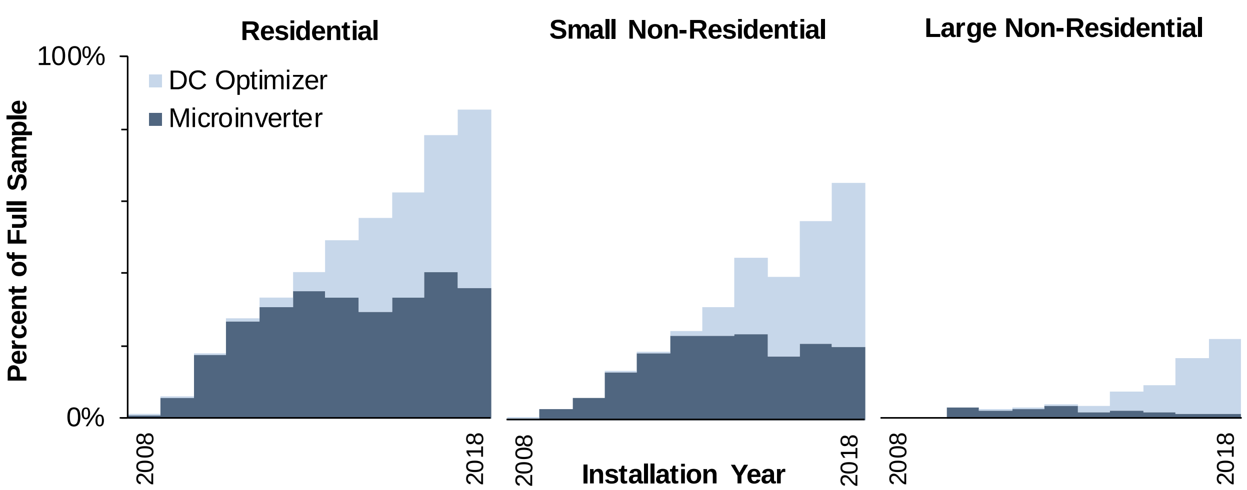
Among 2018 systems in the data sample, module efficiencies range from less than 16% to more than 22%, as shown in Figure 5. Systems at the lower end of that range primarily use poly-crystalline silicon modules, which typically range from 16% to 17.5% efficiency. Systems with mono-crystalline modules are generally higher efficiency, but can span a much wider range, from about 16.5% to 22%, depending in part on whether the cells are p-type or n-type. The growing use of PERC also contributes to the diversity of observed efficiency levels, particularly among mono-crystalline modules where the technology is more prevalent.

As evident in Figure 5, mono-crystalline modules dominate the residential sample (roughly 90% of 2018 installations), but represent progressively smaller shares of the small non-residential (70%) and large non-residential (60%) segments. Accordingly, residential systems had the highest median module efficiency in 2018 at 18.4%, compared to 17.7% for small non-residential systems and 17.4% for large non-residential systems. Differences in module technology choice among customer segments partly reflect greater space constraints in residential applications, as well as less price-sensitivity among residential customers compared to non-residential customers.

Module-Level Power Electronics

Microinverters and DC power optimizers, collectively known as module-level power electronics (MLPEs), offer a number of potential advantages over standard string inverters, including higher performance levels, longer warrantees, and ready-compliance with National Electrical Code (NEC) rapid-shutdown requirements.[6] MLPEs generally sell for a premium over standard inverters, but that price differential has narrowed in recent years (Fu et al. 2018, Wood Mackenzie and SEIA 2019), leading to steady gains in MLPE market share.

This is reflected in the data sample, as shown in Figure 6. MLPE growth has been most pronounced in the residential segment, reaching 85% of all systems in the sample installed in 2018, compared to 64% for small non-residential systems and 22% of large non-residential systems. As evident in the figure, virtually all of the growth in MLPE market share since 2013 has been from DC optimizers, with the microinverter-share remaining fairly flat over that period, and the entirety of MLPE adoption in the large non-residential segment consists of DC optimizers.



Notes: DC Optimizer share consists of only systems with SolarEdge inverters and may therefore slightly understate the actual share of power optimizers in the data sample.

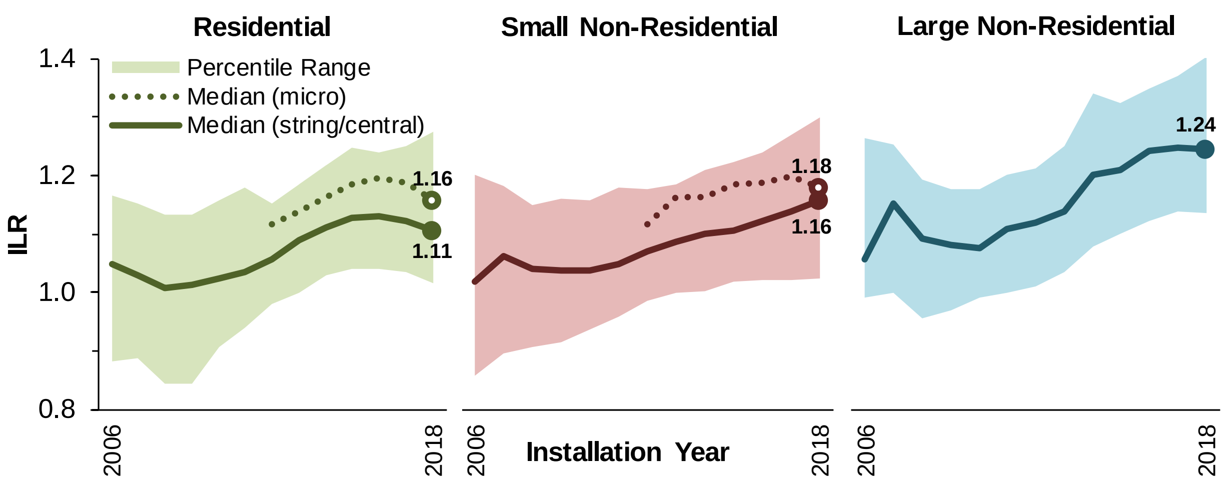
Figure 6. Penetration of Module-Level Power Electronics within the Data Sample

[6] Performance gains are associated primarily with the ability to control the operation of each panel independently, eliminating losses that would otherwise occur on a string when the output of individual panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string. Deline et al. (2012) estimate 4-12% greater energy production from systems with microinverters, which can offset the higher up-front cost of MLPEs.

Differences in MLPE penetration across customer segments in the sample partly reflect the nature of the performance benefits provided by MLPEs. Those benefits arise mostly in cases where PV systems are partially shaded or consist of multiple arrays with differing orientations: conditions that tend to be more prevalent in residential applications (with multiple roof planes and more-constrained space) than in large non-residential applications (where systems are often installed on flat rooftops with uniform orientation and potentially greater flexibility in terms of layout).

Inverter Loading Ratios

The inverter loading ratio (ILR) is the ratio of a PV system's total module nameplate rating (in DC watts) to its total inverter nameplate rating (in AC watts), also sometimes called the DC-to-AC ratio. Most PV systems are designed with ILRs greater than 1.0, that is, with modules oversized relative to the inverter. In general, higher ILRs entail greater clipping of module output during hours of peak production, but can reduce inverter and other BoS costs for a given module array size. In sizing a system's ILR, installers may also consider module degradation, ambient temperatures, and other issues such as soiling and shading that reduce module output relative to its rated capacity.



Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year across all inverter types. Trends are shown starting in 2006, and for micro-inverters in 2012, as the trends for prior years tend to be erratic, partly due to small sample sizes.

Figure 7. Inverter Loading Ratios among Systems in the Data Sample

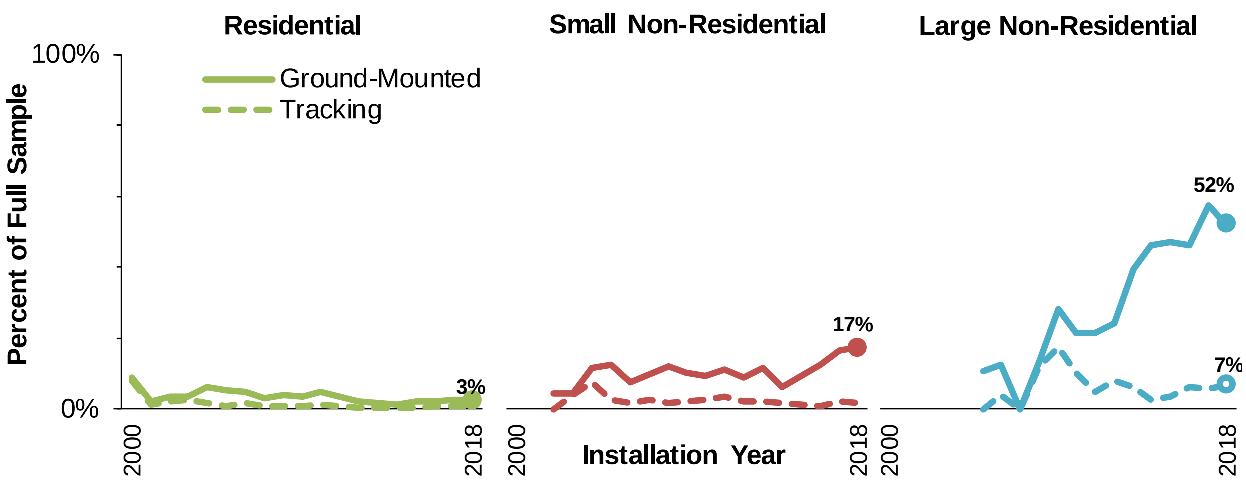
As shown in Figure 7, ILRs for distributed PV systems vary widely, with residential and small non-residential systems installed in 2018 typically ranging from roughly 1.0 to 1.3 and large non-residential systems from 1.1 to 1.4. Within those broad ranges, several specific trends can be seen. First, systems with microinverters tend to have higher ILRs than those with string inverters, though this depends on which microinverter brand is used. Systems with Enphase inverters, which comprise the majority of microinverter systems in the sample, had a median ILR of 1.26 in 2018, while those using SunPower modules with integrated microinverters, which make up most of the remainder, have much lower ILRs (a median of 1.08 in 2018), reflecting the higher module costs.

Second, ILRs have generally risen over time, across all sectors and inverter types. In part, this reflects the steady decline in module costs, which shifts project economics towards higher ILRs. In addition, string inverters are often sized based on the amperage of the customer's electrical service panel; as module efficiencies and PV system sizes have grown over time, ILRs have therefore grown as well. These trends appear to have reversed over the last several years, with median ILRs declining for microinverter systems and for residential string-inverter systems. In the case of micro-inverter systems, that apparent reversal is simply an artifact of the underlying mix of manufacturers, with low-ILR SunPower systems taking on a larger share relative to higher-ILR Enphase systems.

Finally, ILRs tend to be higher for large non-residential systems than for residential and small non-residential systems. In part, that may reflect a greater emphasis among large non-residential systems on minimizing LCOE, which may in turn steer system design towards greater oversizing of the arrays.

Ground-Mounting and Use of Tracking Equipment

Though residential PV systems are generally roof-mounted, many non-residential systems are ground-mounted, including shade structures. As shown in Figure 8, roughly half of all large non-residential systems installed in 2018 were ground-mounted, and that fraction has grown considerably over time in concert with the previously noted trend towards larger system sizes. These systems are still predominantly fixed-tilt, with just 7% of large non-residential systems in 2018 using tracking equipment. This stands in contrast to the utility-scale market, where more than two-thirds of systems in 2018 had tracking (Bolinger and Seel 2019). Within the small non-residential and residential customer segments, progressively smaller fractions of systems are ground-mounted, and negligible percentages (<1%) use tracking.



Notes: Summary statistics for any given year are shown only if at least 20 observations are available.

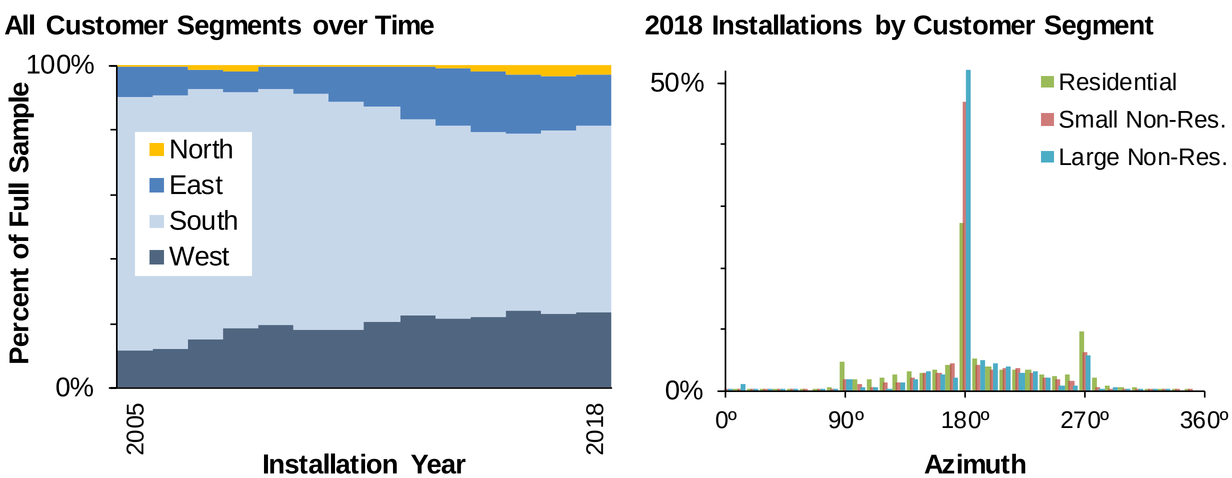
Figure 8. Mounting Configuration among Systems in the Data Sample

Orientation

PV panel orientation (azimuth and tilt) is a key determinant of PV energy production, with the greatest energy production for fixed-tilt systems typically occurring when panels are oriented due south and with tilt equal to the location's latitude. In some cases, however, PV panels may provide greater value to the utility system and potentially to the customer if oriented westward, so that the PV generation profile more closely matches the utility system load profile. That said, many rooftop applications may offer limited flexibility in terms of panel orientation, given existing roof planes.

As shown in the left-hand panel of Figure 9, just over half of PV systems in the 2018 sample are oriented southward (57%), and that fraction has declined over time. The trend toward more diverse panel orientations may reflect both falling rooftop PV costs, allowing systems to become economically viable even with sub-optimal orientations, as well as deeper market penetration in some regions, requiring installers to look beyond the low-hanging fruit of customers with ideally oriented rooftops. Some states and utilities have also begun requiring that rooftop PV customers take service under time-of-use (TOU) rates, which might encourage more westerly oriented systems if peak and off-peak rates sufficiently differ. However, we see little direct evidence of such an effect, as both west-facing and east-facing systems have become more prevalent, comprising 23% and 16% of 2018 installations, respectively. Though not shown in the figure, we also see no meaningful differences in orientation trends between markets with and without TOU rates.

As shown in the right-hand panel of Figure 9, residential and non-residential systems both tend to be oriented in the general southerly direction, though a significantly greater share of non-residential systems than residential systems face exactly due-south. This is likely due to the greater prevalence of both flat rooftops and ground-mounting in the non-residential sector, allowing for more-optimized system orientation. Also of note, the residential and non-residential distributions both exhibit relatively high concentrations of systems with panels facing exactly due-east and due-west; this likely reflects the fact that streets—and therefore houses and rooftops—tend to be oriented along cardinal compass directions.



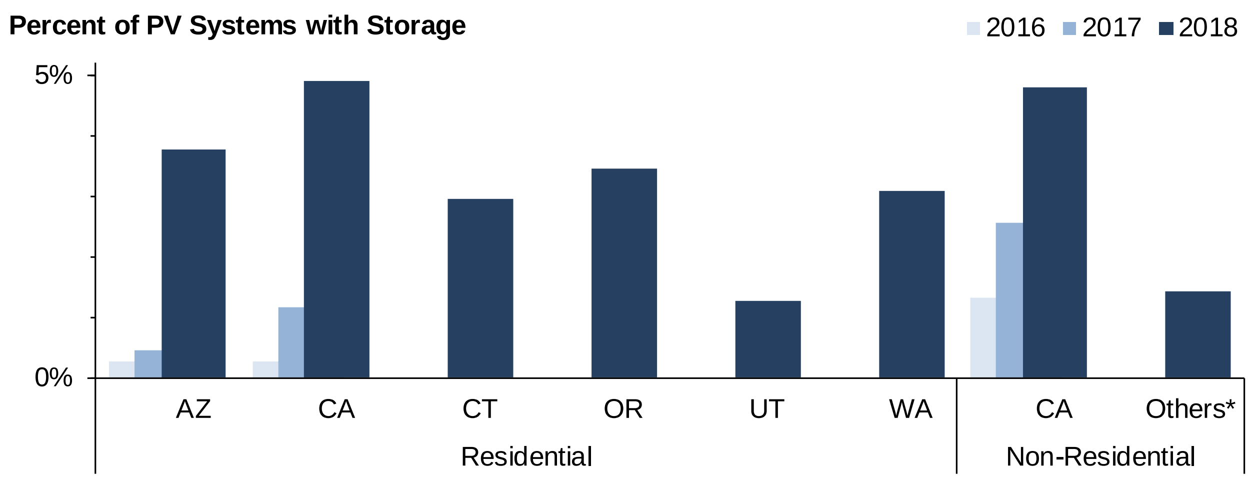
Notes: In the left-hand figure, azimuths are grouped according to cardinal compass directions ±45º (e.g., systems within ±45º of due-south are considered south-facing). Both figures exclude flat-mounted and tracking systems.

Figure 9. Orientation among Systems in the Data Sample

Solar-Plus-Storage

Pairing battery storage with distributed PV has become more common, as storage costs decline, as customers with high reliability needs seek to ride-through outages, and as utilities adopt incentives and implement rate designs that encourage storage adoption. Among those rate designs, net billing rates—an emerging successor to traditional net metering—provide lower levels of compensation for solar generation exported to the grid, thereby incentivizing customers to install storage in order to minimize grid exports (in essence, arbitraging between the grid export-rate and retail rates). Similarly, demand charge rates, which are common in the non-residential sector and have been implemented for residential solar customers in several jurisdictions as well, can provide a powerful impetus for solar-plus-storage (Gagnon et al. 2017, Darghouth et al. 2019).

Within the dataset assembled for this report, data identifying PV systems paired with storage are available for only a subset of states (primarily AZ, CA, CT, OR, UT, and WA), as summarized in Figure 10. Among this set of states, between 1-5% of both residential and non-residential PV systems included storage in 2018. Though still relatively small, these penetration rates have risen rapidly in both AZ and CA, where time series data are available. Within AZ, the highest rates of pairing occur within Salt River Project's service territory, where 20% of residential PV systems in 2018 included storage, due to the combination of a new storage incentive program and demand-charge rates for solar PV customers. Though not included in the Tracking the Sun dataset, HI has seen even greater storage penetration in its distributed PV market, as a result of changes to its compensation scheme for behind-the-meter PV that heavily discourage grid exports. In 2018, more than 60% of all permits issued for distributed PV on Oahu included storage (HI DBEDT 2019).



Notes: The figure includes only those states and years with sufficient sample size and coverage. For non-residential systems, all states other than California with sufficient data are grouped together.

Figure 10. Share of Annual PV Installations with Battery Storage

Third-Party Ownership

The composition of the full data sample reflects the growth, and more recent decline, of third-party ownership. As shown in Figure 11, the TPO share among residential systems in the data sample grew dramatically from 2007 to 2012, reaching nearly 60%. Consistent with broader market trends, however, that share has fallen in recent years, with TPO comprising just 38% of the full residential sample in 2018. That recent trend reflects the emergence of residential loan products as well as a move away from TPO by SolarCity/Tesla, previously the country's largest TPO provider. As noted previously, all TPO systems are removed from the sample for the purpose of analyzing installed-price trends.

TPO market-share within the non-residential sample differs in several respects. Among small non-residential systems, the initial TPO growth was less pronounced, though the recent drop-off is still notable. Among large non-residential systems in the data sample, the TPO share has vacillated over time, but shows no consistent decline. As discussed further below, many non-residential systems are installed at tax-exempt customer sites, which serves to sustain some continuing appetite for TPO in order to monetize tax benefits.

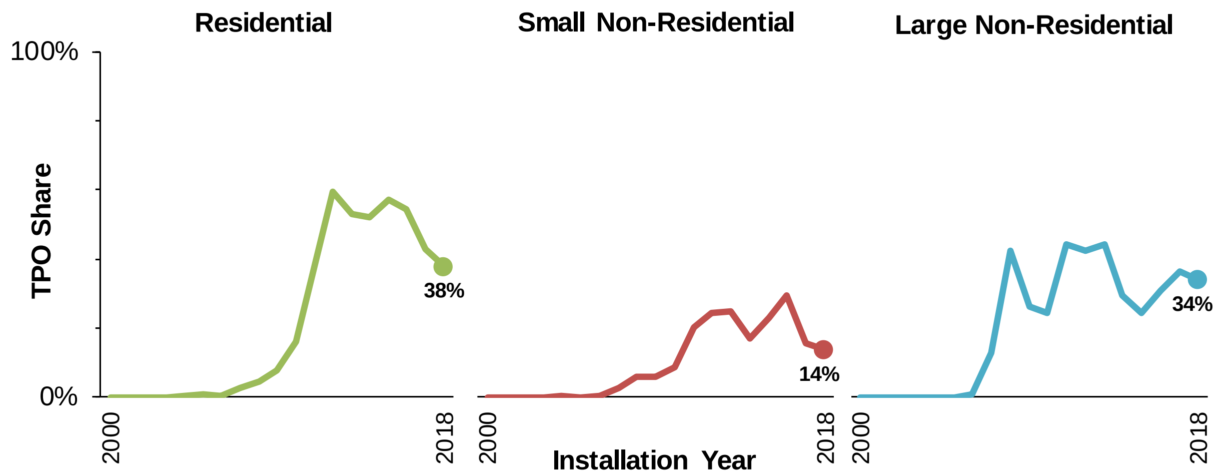


Figure 11. Sample Distribution between Host-owned and TPO Systems

Non-Residential Customer Segmentation

The non-residential solar sector consists of a diverse set of customer types, including for-profit commercial entities, as well as a sizeable contingent of systems installed at schools, government buildings, and non-profit organizations. That latter set we collectively refer to as "tax-exempt" customers. In 2018, roughly 80% of all non-residential systems were installed at for-profit commercial sites, while the remaining 20% were at tax-exempt customer sites, and that overall mix is generally consistent across a number of the larger state markets shown in Figure 12. That 80/20 split is also consistent with analysis performed by Hoen et al. (2019), which examined non-residential PV addresses matched to proprietary datasets of property types.

In general, TPO is more common among tax-exempt customers, as these customers are generally unable to directly monetize tax benefits and therefore rely on third-party owners to capture (and pass on) those benefits. In aggregate across all non-residential systems in the sample, 40% of systems at tax-exempt sites were TPO in 2018, compared to 14% at commercial customer sites. These percentages, however, can vary quite a bit from state to state; in Massachusetts and New Jersey, for example, 60-80% of systems at tax-exempt sites were TPO.

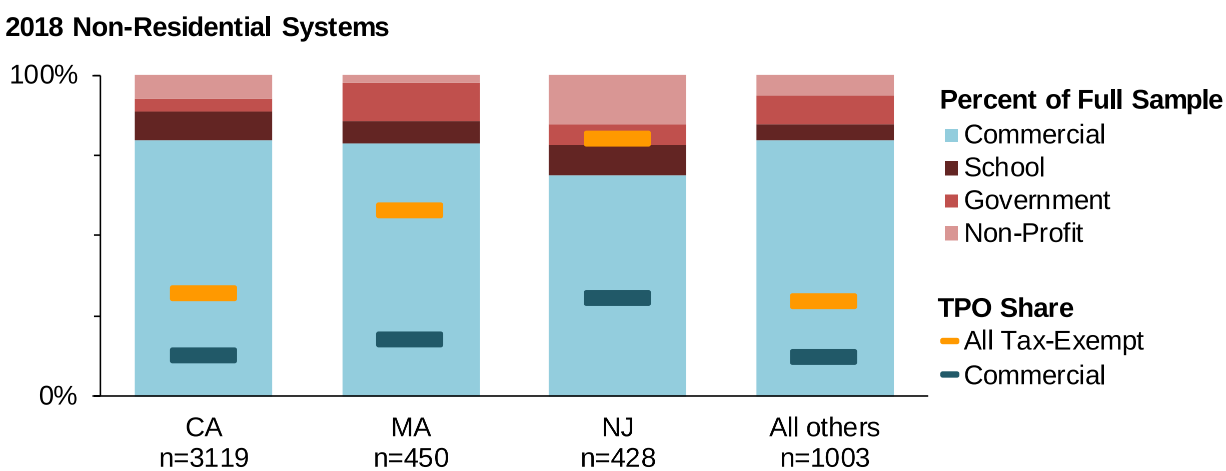


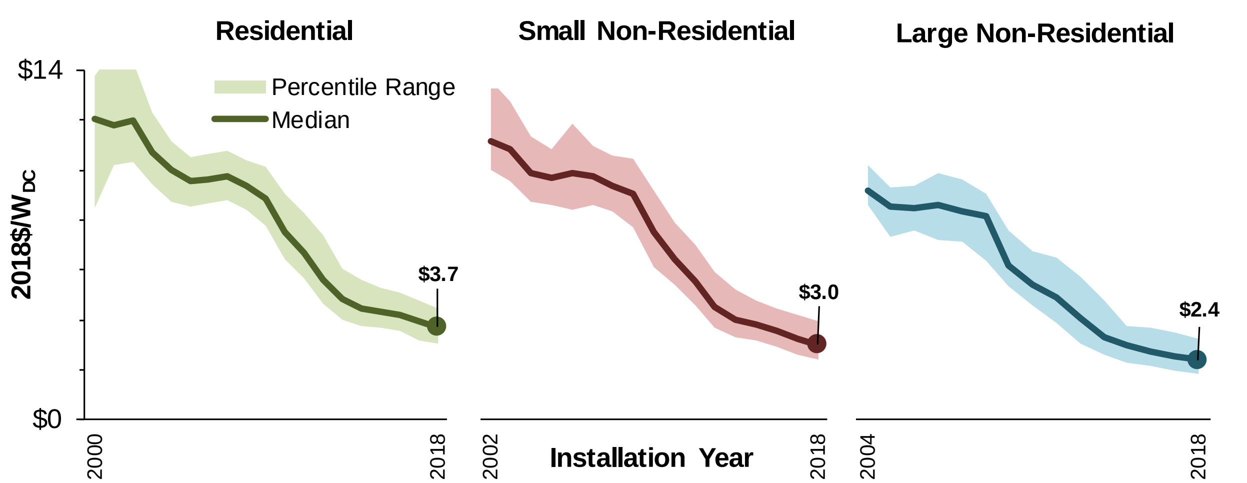
Figure 12. Non-Residential Customer Segmentation and TPO Shares

4. Temporal Trends in Median Installed Prices

This section presents an overview of both long-term and more-recent historical trends in the installed price of distributed PV, focusing on *national median prices* derived from the installed-price data sample described earlier. The section begins by describing the installed price trajectory over the full historical period through 2018, along with preliminary data for the first half of 2019. While the installed-price analysis otherwise focuses on host-owned systems, Text Box 3 compares prices for host-owned and TPO systems, as a point of reference. The section then discusses a number of broad drivers for those historical trends, including underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. It then compares median installed prices between the LBNL dataset and other recent benchmarks for the installed price or cost of distributed PV.

Installed Price Trends: 2000-2018

National median installed prices for host-owned PV systems in 2018 were \$3.7/W for residential systems, \$3.0/W for small non-residential systems, and \$2.4/W for large non-residential systems. As evident in Figure 13, installed prices across all three segments have fallen dramatically over time, though those trajectories have not been smooth. Following a period of particularly steep price declines from 2009-2014, the pace of installed price declines has tapered off. Over the last year of the analysis period, median prices fell by \$0.2/W (5%) for residential systems, by \$0.2/W (7%) for small non-residential systems, and by \$0.1/W (5%) for large non-residential systems. Those declines are largely in line with the rate of price declines observed since 2014. By comparison, long-term annual price declines, over the full analysis timeframe, averaged roughly \$0.5/W per year across all three customer segments.



Notes: Percentile Range represents the band between the 20th and 80th percentile values in each year. Statistics shown only if at least 20 observations available for a given year and customer segment. See Table 1 for annual sample sizes.

Figure 13. Installed Price Trends over Time

The slowing pace of installed price declines in recent years, relative to the rapid rate over the 2009-2014 period, reflects a number of broad trends. First and foremost is the underlying trajectory of module prices. As discussed further in the next section, the rapid installed-price declines that began in 2009 were fueled primarily by a correspondingly rapid drop in global module prices. As module-price declines began to slow in 2013, so too did the decline in system-level pricing (albeit with some lag). On the non-hardware side, cost declines in the residential sector have been dampened by higher customer acquisition costs as early adopters are converted, and by a greater emphasis on profitability by large installation firms. More generally, opportunities for cost reductions across the PV value chain may be diminishing as the market matures and the easiest opportunities for efficiency gains are exploited. Residential loan products have also become more prevalent, wherein various fees are often embedded in the installed prices paid by customers and reported to PV incentive program administrators.[7] PV systems are also increasingly bundled with other products (such as battery storage), and though we attempt to exclude such systems from our data sample, that screening is undoubtedly incomplete.

Text Box 3. Installed Prices for Third-Party Owned Systems

As discussed in Section 2, TPO systems are excluded from the installed-price analysis in this report. Installed prices reported for TPO systems in some cases represent an appraised value or a fair-market value, as may be used as the basis for the federal investment tax credit. In other cases, installed prices reported for TPO systems may be the transaction price between an installation contractor and a third-party financier. Even in that case, however, the underlying goods and services conveyed under that transaction may vary greatly from one system to another. For example, customer acquisition and project development functions for some TPO systems may be performed by the financier or some other entity, rather than the installer, in which case the reported price may reflect only hardware and direct installation labor costs. It is for these various reasons that the installed-price analysis in this report focuses exclusively on host-owned systems.

For reference, Figure 14 compares reported installed prices for all TPO systems and host-owned systems over time. In recent years, median prices for TPO and host-owned systems have coincided quite closely. At earlier points in time, however, pricing for the two groups have diverged, particularly in the residential sector, where TPO prices have been notably higher than for host-owned systems. The convergence over time likely reflects, at least in part, changes in the reporting conventions of TPO companies. Excluding these systems from the installed-price analysis thus avoids any associated distortion in long term pricing trends.

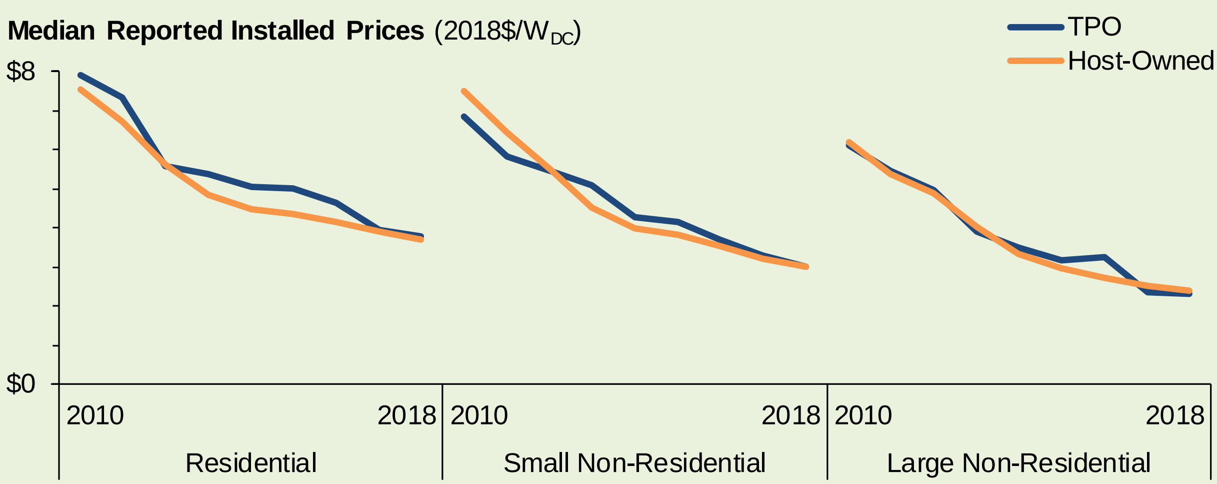


Figure 14. Comparison of Installed Prices between TPO and Host-Owned Systems

[7] Based on data from Wood Mackenzie (2019), roughly two-thirds of all host-owned residential systems installed in 2018 were loan-financed.

Trends in aggregate, national median installed prices are, in effect, a composite of trends among the largest state markets in the dataset. Within the residential segment, median prices fell year-over-year (YoY) by roughly $0.0-0.2/W across the five largest states in the dataset, as shown in Figure 15. Notably, all five saw lower annual price declines than the aggregate national drop. By extension, smaller markets saw larger declines, suggestive of the greater cost-saving opportunities that may exist in less mature markets. Among non-residential systems, YoY changes in median installed prices varied much more dramatically across states, as might be expected given the more-diverse set of projects and smaller sample sizes. For that reason, YoY changes in median prices for non-residential systems can be somewhat erratic, at both the state and national levels.

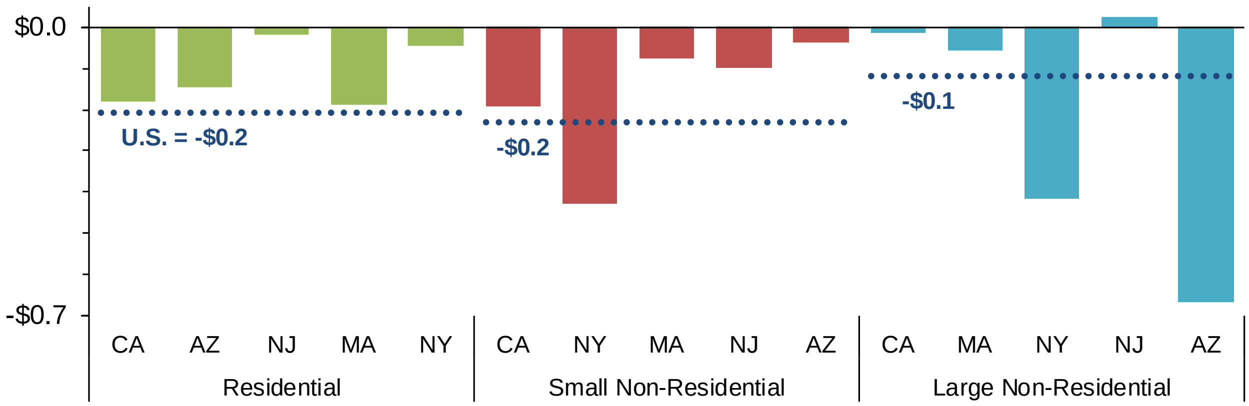


Figure 15. Annual Change in Median Installed Price for Largest State Markets in the Data Sample

Installed Price Trends: Preliminary Data for 2019

Preliminary data for the first six months of 2019, based on the largest state markets in the sample, show a continuing but modest decline in national median prices—at least for the residential and large non-residential segments. As shown in Figure 16, median installed prices for the first half (H1) of 2019 fell by an additional $0.1/W for both the residential and small non-residential segments, relative to H1 2018, while median prices for small non-residential systems rose slightly. As noted previously, recent price declines in these state have been lower than in other, mostly smaller state-markets, and therefore the trends shown in Figure 16 may understate the drop in national median prices over the first half of 2019.

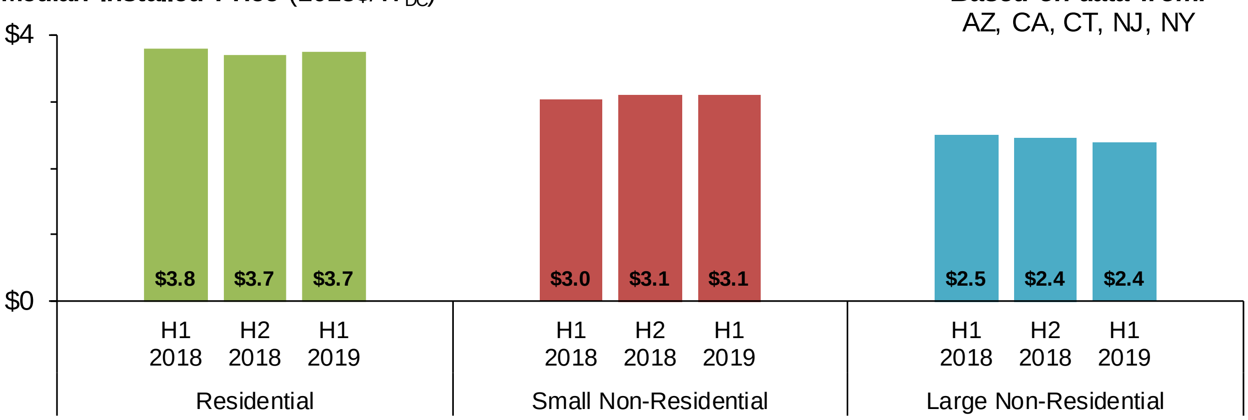


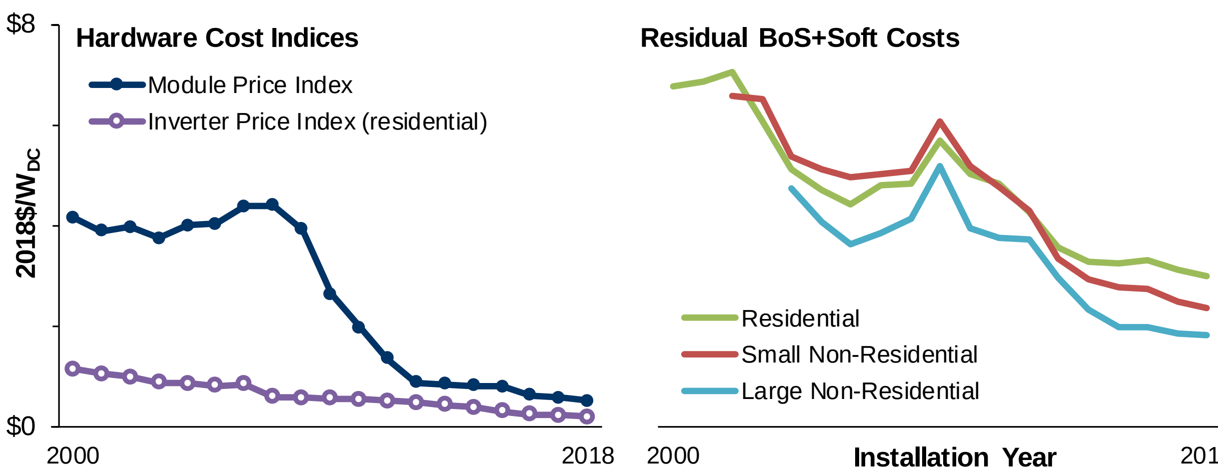
Figure 16. Median Installed Prices for Systems Installed in 2018 and the First Half of 2019

Underlying Hardware and Soft Cost Reductions

Long-term installed-price declines reflect the combined effect of reductions in both hardware and non-hardware costs. Among hardware costs, PV modules have been, far and away, the largest single driver for system-level installed-price declines over the long term. Based on the indices shown in the left-hand panel of Figure 17, module prices have fallen by roughly $3.6/W since 2000—with most of that drop occurring over the 2008-2012 period—while inverter prices have fallen by roughly $0.9/W. Price reductions for these two primary hardware components equate to roughly 44% and 11% of the long-run decline in median residential system prices, and roughly similar proportions for both small and large non-residential systems.

The remaining long-term drop in installed prices is associated with other balance of systems (BoS) costs, such as racking and wiring, and the wide assortment of "soft" costs, which include customer acquisition, system design, installation labor, permitting and inspection costs, installer margins, and loan-related fees in some cases. While hardware costs are largely global in nature, soft costs can be more directly affected by local market conditions. BoS and soft costs are, together, captured by the set of residual terms shown in the right-hand panel of Figure 17. Those residual BoS+soft costs have declined significantly over time, constituting 45% of the long-term drop in median residential installed prices (and similar percentages for non-residential customers).[8]

Over the more recent term since 2014, following the steep drop in global module prices, installed price declines have continued to be driven by both hardware and soft-cost reductions. Based on the price indices in Figure 17, modules and inverters represent roughly 38% and 28%, respectively, of the decline in median residential system prices since 2014, with the remaining 36% associated with residual BoS and soft costs. For non-residential systems, installed price declines since 2014 have been more heavily driven by BoS and soft-cost reductions, representing roughly 55% of total installed price reductions.



Notes: The Module Price Index is the U.S. module price index published by SPV Market Research (2019). The Inverter Price Index is a weighted average of string inverter and microinverter prices published by Wood Mackenzie and SEIA (2019), based on the mix for each segment, extended backwards in time using inverter costs reported for systems in the LBNL data sample. The Residual term for each customer segment is calculated as the median installed price for that segment minus the Module Price Index and the corresponding Inverter Price Index for that customer segment.

Figure 17. Installed Price, Module Price Index, Inverter Price Index, and Residual Costs over Time

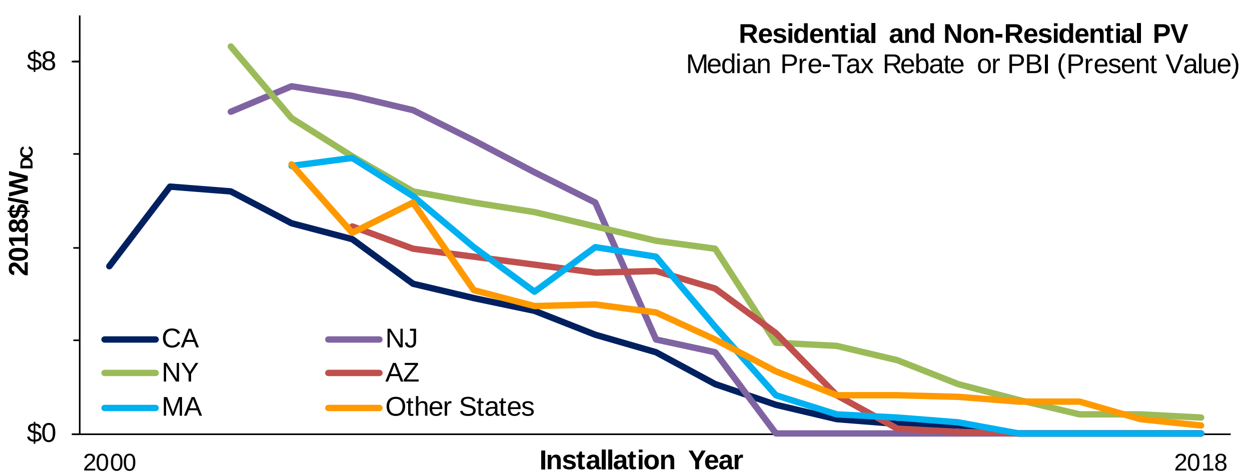
[8] The apparent "spike" in the residual BoS+soft cost term during the middle of the analysis period is a computational artifact associated with the lag between changes in global module prices and in total installed prices.

Long-term declines in soft costs reflect a wide diversity of underlying drivers—some related to the broader policy and market environment (e.g., maturation of the industry, declining incentives, etc.) and others more-technical in nature. Two specific technical factors, both described previously, are the steady and significant increases over time in both system sizes and module efficiencies. Increasing system sizes reduce BoS and soft costs on a per-watt basis by allowing fixed project costs (e.g., permitting and customer-acquisition) to be spread over a larger base of installed watts, while increasing module efficiencies reduce BoS and soft costs by, in effect, allowing system sizes to increase with a less-than-proportional increase in the physical footprint of the system, thereby reducing area-related costs (e.g., racking and installation labor) relative to what would have occurred with lower efficiency modules.

Declining State and Utility Cash Incentives

Financial incentives provided through utility, state, and federal programs have been a driving force for the PV market in the United States. For residential and non-residential PV, those incentives have—depending on the particular place and time—included some combination of cash incentives provided through state and/or utility PV programs (rebates and performance-based incentives), the federal investment tax credit (ITC), state ITCs, revenues from the sale of solar renewable energy certificates (SRECs), accelerated depreciation, and retail rate net metering.

Focusing *solely* on direct cash incentives provided in the form of rebates or performance-based incentives (PBIs), Figure 18 shows how these incentives have declined steadily and significantly over the past decade. At their peak, most programs were providing incentives of $4-8/W (in real 2018 dollars). Over time, direct rebates and performance-based incentives have been largely phased-out in the larger state markets—including Arizona, California, Massachusetts, and New Jersey—and have diminished to below $0.5/W in most other locations. This continued ratcheting-down of incentives is partly a response to the steady decline in the installed price of PV and the emergence of other forms of financial support (for example, SRECs, as discussed in Text Box 4). At the same time, incentive declines may have also helped to motivate further cost and price reductions, as installers were forced to cut costs to remain competitive. The steady ratcheting down of incentives has thus likely been both a cause and an effect of long-term installed price reductions.



Notes: The figure depicts the pre-tax value of rebates and PBI payments (calculated on a present-value basis) provided through state and utility PV incentive programs.

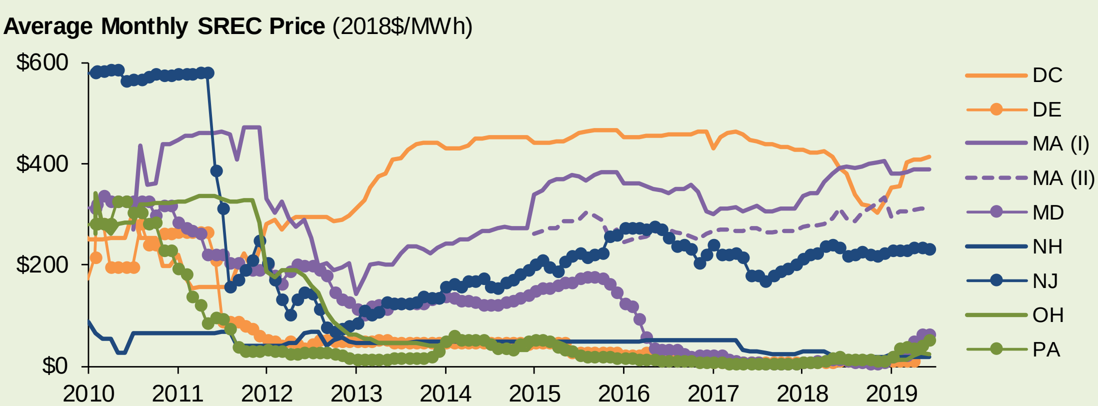
Figure 18. State/Utility Rebates and PBIs over Time

From the perspective of the customer-economics of PV, however, one thing is clear: the steady reduction in cash incentives has offset reductions in (pre-incentive) installed prices to a significant degree. Among the five state markets profiled in Figure 18, the decline in incentives from each market's respective peak is equivalent to anywhere from 66% to 100% of the drop in installed PV prices over the corresponding time period. Of course, other forms of financial support have simultaneously become more lucrative over this period of time—for example, the federal ITC for residential solar rose in 2009, and SREC markets emerged in many states; new financing structures have also allowed greater monetization of existing tax benefits. And while net metering rules and rate design for solar PV customers have come under greater scrutiny, most of the large state markets have yet to make any substantial changes to those structures. The customer economics of solar in many states thus has likely improved, on balance, over the long-term, but the decline in state and utility cash incentives has nevertheless been a significant counterbalance to falling installed prices.

Text Box 4. SREC Price Trends

Fifteen states plus the District of Columbia have renewables portfolio standards (RPS) with a solar or distributed generation set-aside (also known as a "carve-out"), and many of those states have established solar renewable energy certificate (SREC) markets to facilitate compliance. An SREC represents the solar "attribute" created by 1 MWh of solar-electricity generation, and can be transacted separately from the underlying electricity for purposes of facilitating compliance with RPS obligations or voluntary green energy goals. PV system owners in states with RPS solar carve-outs, and in some cases neighboring states, may sell SRECs generated by their systems, either in addition to or in lieu of direct cash incentives received from state/utility PV incentive programs. Many solar set-aside states have transitioned away from standard-offer based incentives, particularly for larger and non-residential systems, and towards SREC-based incentive mechanisms with SREC prices that vary over time.

Prior to 2011, SREC prices in most major RPS solar set-aside markets ranged from $200 to $400/MWh, topping $600/MWh in New Jersey (see Figure 19). Starting around 2011 or 2012, SREC supply began to outpace demand in these markets, leading to a steep drop in SREC pricing. As with the broader decline in solar incentives, this contraction in SREC pricing served as a source of further downward pressure on installed prices. Since then, SREC prices in several key markets (DC, MA, and NJ) have risen or stabilized, easing some of that downward pressure on installed prices. In other states, low SREC prices have persisted, as local RPS solar carve-out markets remain over-supplied.



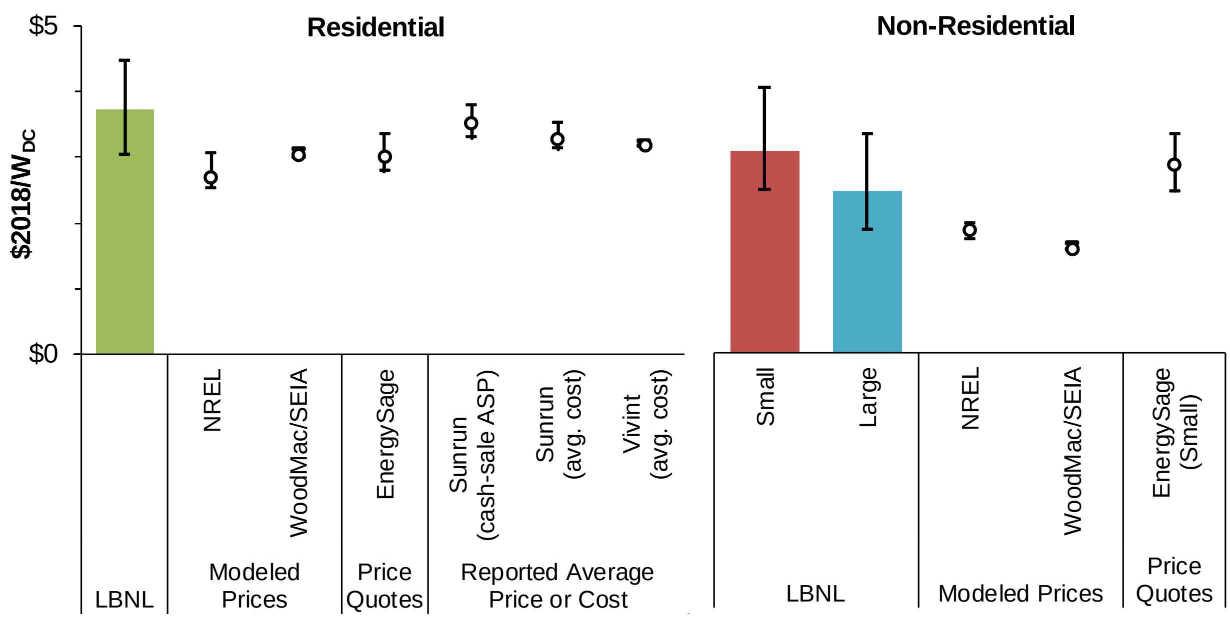
Notes: Data sourced primarily from Marex-Spectron. Plotted values represent SREC prices for the current or nearest future compliance year traded in each month. MA (I) and MA (II) refer to prices in the SREC I and SREC II programs, respectively.

Figure 19. Solar Renewable Energy Certificate Spot-Market Prices

Comparison to Other U.S. PV Cost and Pricing Benchmarks

National median prices can provide a useful metric for characterizing aggregate trends, but may not provide the most relevant benchmark for system prices in all contexts. To provide a broader view of PV system pricing, Figure 20 compares median installed prices of 2018 systems from the LBNL data sample to a diverse set of other recent PV price and cost benchmarks. These other benchmarks include modeled PV system prices, price quotes for prospective PV systems, and average costs reported directly by several major residential installers, as described further in the figure notes.

Not surprisingly, the various benchmarks differ from one another, in some cases considerably so, reflecting underlying differences in data, methods, and definitions. In general, national median prices drawn from the LBNL dataset are higher than the other PV pricing benchmarks shown in the figure, for reasons such as those noted in Text Box 5. The other benchmarks are, instead, generally more closely aligned with 20th percentile pricing levels in the LBNL dataset, and may be representative of “best in class” or “turnkey” systems and/or relatively low cost markets. Later sections of this report further explore the wide spread in the LBNL data and show how prices observed in many contexts—e.g., for certain states, installers, and module technologies—are substantially below the national median, and may correspond more closely to the other pricing benchmarks in Figure 20.



Notes: ***LBNL*** *data are the median and 20th and 80th percentile values among projects installed in 2018.* ***NREL*** *data represent modeled turnkey costs in Q1 2018 for a 6.2 kW residential system (range across system configuration and installer type, with weighted average) and a 200 kW commercial system (range across states and national average) (Fu et al. 2018).* ***WoodMac/SEIA*** *data are modeled turnkey prices for 2018 (the average, min, and max of quarterly estimates); their residential price is for a 5-10 kW system with standard crystalline modules, while the commercial price is for a 300 kW flat-roof system (Wood MacKenzie and SEIA 2019).* ***EnergySage*** *data are the median and 20th and 80th percentile range among price quotes issued in 2018, calculated by Berkeley Lab from data provided by EnergySage; quote data for non-residential systems are predominantly from small (<100 kW) projects.* ***Sunrun*** *and* ***Vivint*** *data are the companies’ reported average selling prices or ASP (Sunrun only) or costs in 2018 (the average, min, and max of quarterly values).*

Figure 20. Comparison to Other Installed Price or Cost Benchmarks

Text Box 5. Reasons for Differences between LBNL National Median Prices and Other Benchmarks

Variation across the benchmarks shown in Figure 20 arise for a number of reasons, and help to explain why median values drawn from the LBNL data sample tend to be higher than the other benchmark values:

- *Timing*: The LBNL data in Figure 20 are based on systems installed in 2018. A number of the other benchmarks cited in the figure are instead based on price quotes issued in 2018, which may precede installation by several months to even a year or more (especially for non-residential projects).
- *Price versus cost:* The LBNL data represent prices paid by PV system owners to installers or project developers. In contrast, the cost data drawn from Sunrun's and Vivint's publicly available financial reports represent costs borne by those companies, which exclude profit margins and, for a variety of other reasons, may differ from the prices ultimately paid by PV system owners. Notably, though, Sunrun also reports average selling prices (ASPs) for its cash-sale systems, which are quite similar to the median prices drawn from the LBNL dataset.
- *Value-based pricing*: Benchmarks may reflect developer/installer margins based on some minimally sustainable level, as may occur in highly competitive markets. In contrast, the market price data assembled for this report are based on whatever profit margin developers are able to capture or willing to accept, which may exceed a theoretically competitive level in markets with high search costs and/or barriers to entry.
- *Location:* As noted earlier, statistics derived from the LBNL dataset are dominated by several high-cost states that constitute a large fraction of the sample (and of the broader U.S. market). Other benchmarks may instead be representative of lower-cost or lower-priced locations.
- *System size and components*: A number of the benchmarks in Figure 20 are based on standard, turnkey project designs. The LBNL data instead reflect the specific sizes and components of projects in the sample.
- *Scope of costs included*: The set of cost components embedded in the installed price data collected for this report undoubtedly varies across projects, and in some cases may include optional add-ons, such as extended warranties or monitoring and maintenance services, as well as items such as re-roofing costs or loan-related fees that typically would not be included in other PV pricing benchmarks (though, from the customer's perspective, are nevertheless part of the price of "going solar").
- *Installer characteristics*: Finally, the LBNL data reflect the characteristics and reporting conventions of the particular installers in the sample, many of which are relatively small or regional firms, particularly given the focus here on host-owned systems. Other benchmarks in Figure 20 may instead be more representative of large installers.

5. Variation in Installed Prices

While the preceding section focused on temporal trends in median installed prices, this section instead focuses on *variability* in installed prices observed among projects in the dataset—again, focusing on host-owned residential and non-residential systems. The section begins by describing the overall distribution in installed prices across the dataset as a whole. It then explores potential sources of this pricing variation, first through a basic descriptive analysis comparing median prices for different groups of systems. This includes pricing differences based on: system size, state, installer, module efficiency, inverter technology, residential new construction vs. retrofit, tax-exempt vs. commercial site hosts, and mounting configuration. The section then presents the results of a multi-variate regression analysis, which focusing specifically on residential systems and seeks to better isolate the effects of individual pricing drivers. Those price drivers including those factors addressed in the descriptive analysis as well as a number of other characteristics of the local PV markets and installers.

Overall Installed Price Variability

The installed price data exhibits considerable spread, as evident in Figure 21, and that spread has largely persisted over time (as evident by referring back to Figure 13, presented earlier in the report). Among residential systems installed in 2018, roughly 20% were priced below \$3.1/W (the 20th percentile value), while 20% were above \$4.5/W (the 80th percentile). Non-residential systems exhibit similar spreads, with 20th-to-80th percentile bands of \$2.4/W to \$4.0/W for small non-residential systems and \$1.8/W to \$3.3/W for large non-residential systems. As shown, these distributions have relatively long right-hand tails, skewing the percentile values towards right. Thus, what might be deemed "typical" system pricing is closer to the 20th percentile level than to the 80th. Prices at the far right-hand end of these distributions may, in some cases, include additional items beyond the PV installation (e.g., re-roofing costs), but these distributions nonetheless illustrate the substantial variability in PV system pricing currently observed in the market.

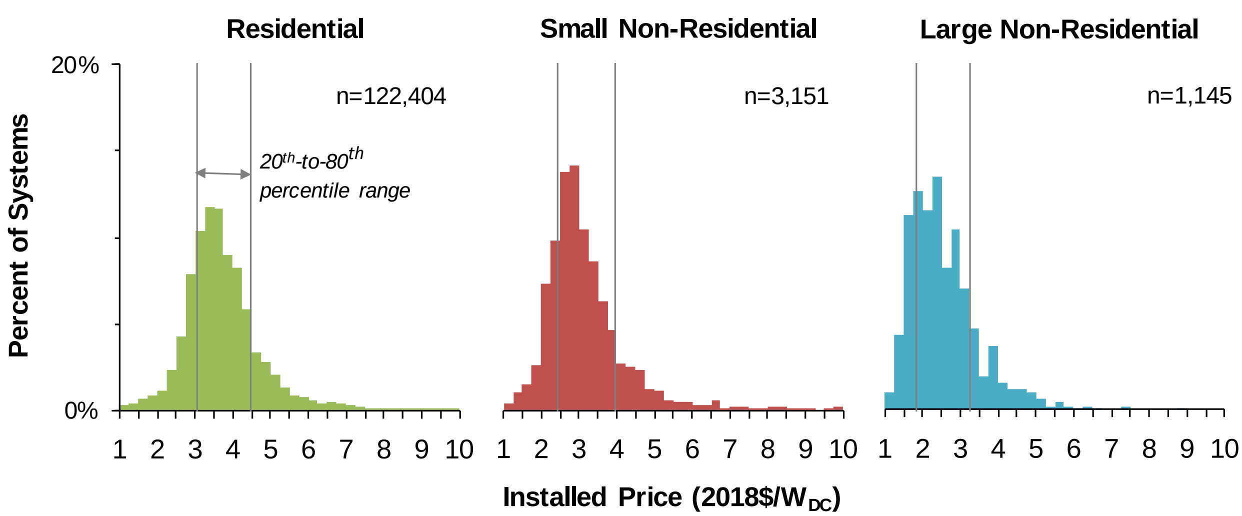


Figure 21. Installed Price Distributions for Systems Installed in 2018

The potential underlying causes for this persistent pricing variability are numerous, including differences in project characteristics and installer attributes, as well as various aspects of the broader distributed solar market, policy, and regulatory environment. The remainder of this report explores many of these potential drivers. This discussion adds to the growing body of literature on distributed PV pricing, much of which has drawn on the same data as described in this report (see, for example, Burkardt et al. 2014; Dong and Wiser 2013; Dong et al. 2014; Gillingham et al. 2014; Nemet et al. 2016a, 2016b, and 2017; and O'Shaughnessy 2018). For a broad review of the literature on PV pricing drivers, see O'Shaughnessy et al. 2019.

Pricing by System Size

Larger PV installations benefit from economies of scale by spreading fixed project and overhead costs over a larger number of installed watts. These scale economies are evident when comparing between residential and non-residential systems. As shown in Figure 22 and Figure 23, they also arise within each customer segment, and, indeed, are one of the largest single drivers for observed pricing variability.

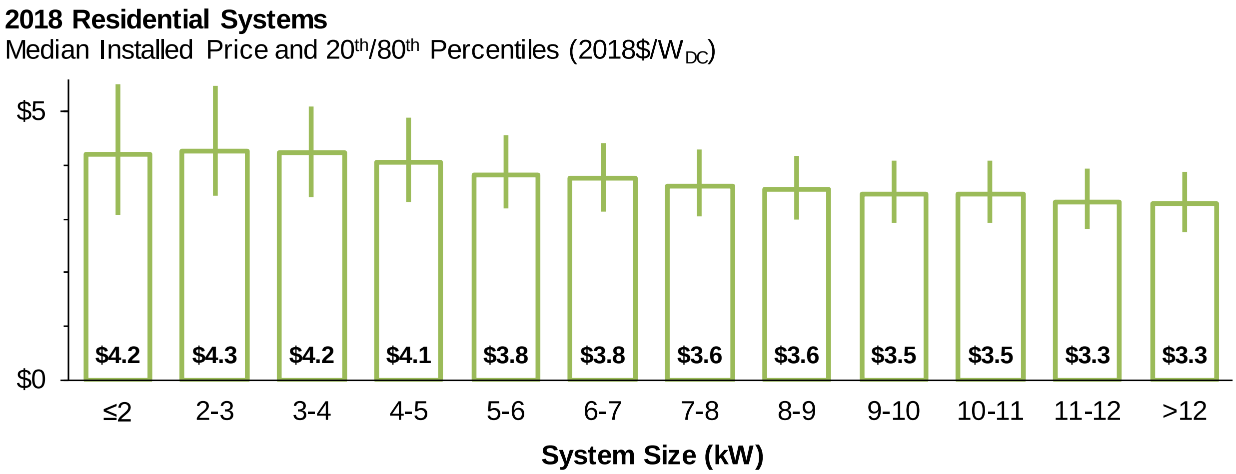
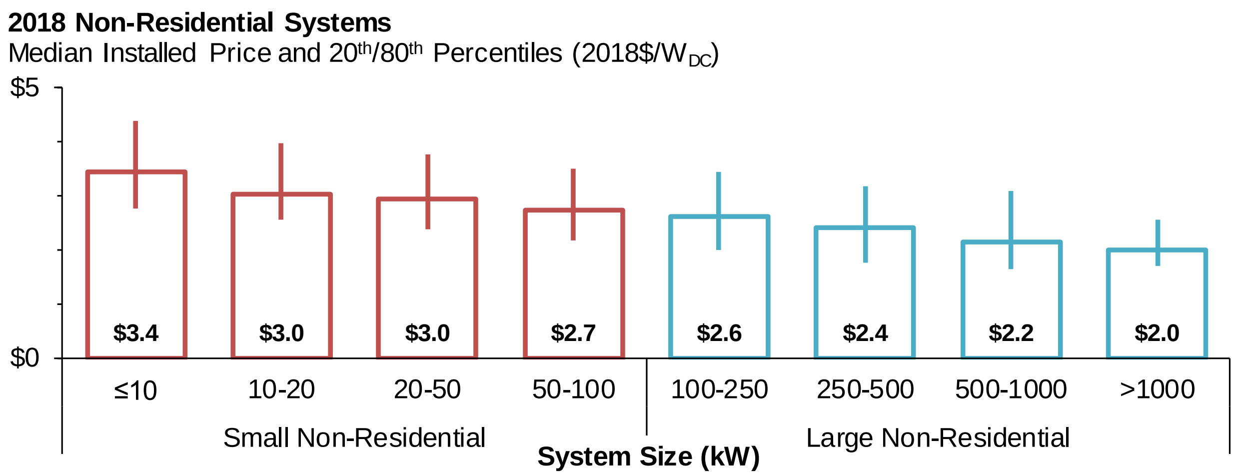


Figure 22. Installed Price of 2018 Residential Systems by Size



* *See Text Box 2 for details on the upper bound size of non-residential systems, as defined for this report.*

Figure 23. Installed Price of 2018 Non-Residential Systems by Size

Among residential systems installed in 2018, median prices at the far upper end of the size spectrum were roughly $1.0/W lower than at the lower end. Across the narrower range between the 20th and 80th percentile system sizes (4.2 kW and 9.6 kW), median installed prices differed by $0.6/W. As evident in the figure, price declines taper off with increasing size, consistent with diminishing returns to scale. The regression analysis presented later in this report shows the same general pattern, but somewhat larger overall effects.

Economies of scale among non-residential systems are even more pronounced, given the order-of-magnitude larger range in system sizes. Among systems installed in 2018, median installed prices were $1.4/W lower for the largest class of non-residential systems >1,000 kW in size than for the smallest systems. Non-residential systems also exhibit diminishing returns to scale, though this is obscured in the figure, as the bin intervals become progressively wider at larger system sizes. Note again that ground-mounted non-residential systems in this report are capped at 5 MW_{AC}; larger systems are considered utility-scale and exhibit even lower prices (see Bolinger and Seel 2019).

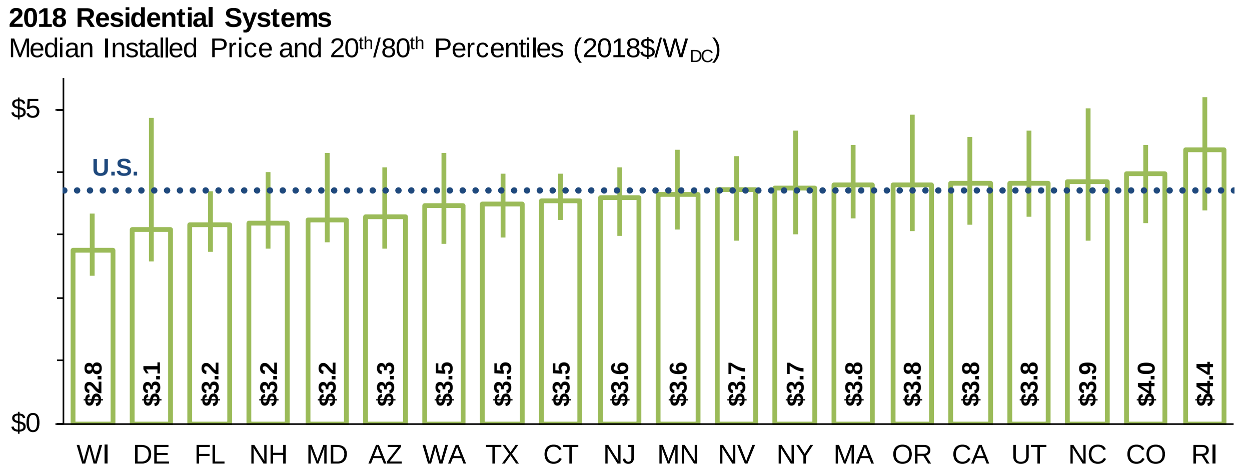
Pricing across States

The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Focusing on state-level differences, Figure 24 and Figure 25 compare median prices of residential and non-residential systems installed in 2018. Among residential systems, median prices ranged from a low of $2.8/W in WI to a high of $4.4/W in RI. Pricing for small non-residential systems varied across a similarly wide range, from $2.5/W in WA to $3.7/W in MN, while cross-state differences among large non-residential systems were somewhat smaller, ranging from a median of $1.7/W in CO to $2.5/W in CA. Some of these differences may simply be the result of peculiarities in the underlying data—particularly for states with relatively small sample sizes—but they also reflect other, more fundamental drivers.

State-level pricing differences stem, in part, from underlying market conditions, such as market size and competition. In particular, one might anticipate that larger state markets (in terms of number of installations) would tend to have lower prices. In fact, the descriptive results presented here would seem to suggest the exact opposite, as some of the largest state markets (CA, MA, and NY) are all relatively high-priced. The regression analysis presented later in this report, however, finds that larger markets are generally associated with lower prices; other confounding differences simply drown out those impacts in the figures below. Prices can also vary across markets based on competitive factors, as may be measured in terms of the number of installers operating in a market and/or the level of concentration among a small set of installers, as the later regression analysis and other studies (Gillingham et al. 2014, O'Shaughnessy 2019) show.

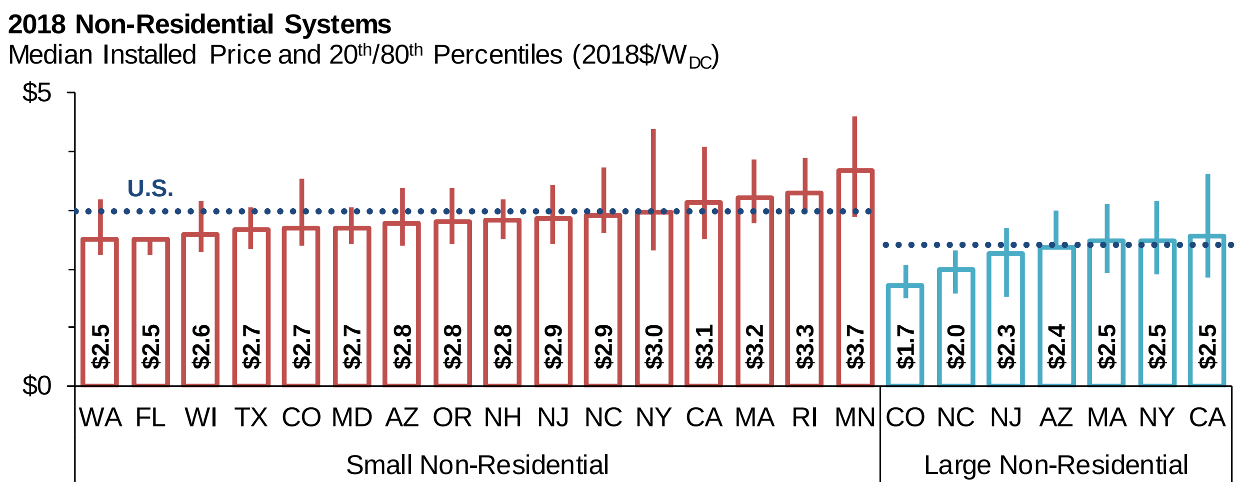
Policy differences across states can also impact installed prices. Many studies, for example, have evaluated the impacts of rate design and incentive levels on (pre-incentive) PV prices. Collectively, these studies have come to varying conclusions—in some cases finding significant effects (Gillingham et al. 2014, Borenstein 2017) and in others not (Dong et al. 2014). Local permitting, interconnection, and other regulatory processes can also impact PV pricing (Dong and Wiser 2013, Burkhardt et al. 2014). Those processes are typically defined at the local municipal or county level, but in aggregate, may impact state-level pricing. Sales taxes also vary across states, and many states exempt PV from sales tax, leading to as much as a $0.3/W difference in installed prices across states. Other unique state-level policy factors may also impact costs; for example, most of the data for Minnesota come from the state's "Made in Minnesota" program, which requires the use of in-state manufactured products.

Finally, state-level pricing differences also reflect systemic differences in PV system design, associated with climate or characteristics of the local building stock or building standards. For example, residential system sizes vary from a median of 5.3 kW in CO to 9.3 kW in WA, perhaps partly due to differences in solar irradiance levels. Racking costs can vary across states, depending on typical roofing materials and on wind and snow loading. In addition, many of the higher-priced states also have a particularly high share of systems with premium efficiency (>20%) modules, and as shown later, those systems tend to be considerably higher priced than others.



Notes: Median installed prices are shown only if at least 20 observations are available for a given state.

Figure 24. Installed Price of 2018 Residential PV Systems by State



Notes: Median installed prices are shown only if at least 20 observations are available for a given state.

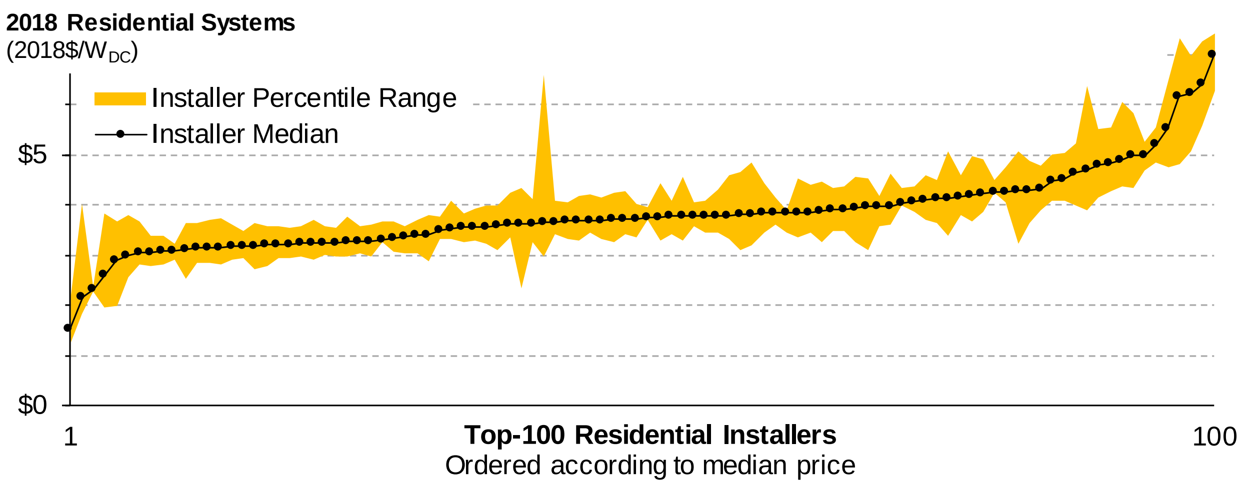
Figure 25. Installed Price of 2018 Non-Residential PV Systems by State

Pricing across Installers

The U.S. PV market is serviced by a large number of installers of varying size, experience, and business models. Although the residential market, in particular, has historically been dominated by several large national companies, a great many regional firms and small local installers operate throughout the country. In total, the data sample assembled for this report includes roughly 4,000 companies that installed PV systems in 2018, primarily in the residential sector.[9] Of those, roughly two-thirds installed fewer than 10 systems over the course of the year, and just over 250 companies had more than 100 installs.

Pricing can and does vary considerably across individual installers, as shown in Figure 26, which focuses on the 100 residential installers with the most systems installed last year. These companies each installed between roughly 200 and 4500 host-owned systems last year, and collectively represent 45% of all systems in the installed-price dataset. Ignoring the tails of this curve, median prices across these installers ranged from roughly $3.0/W to $5.0/W, with most below $4.0/W.[10]

To some extent, these pricing differences simply reflect each company's unique pricing strategy and the margin it is willing to accept. One might also expect pricing to vary according to firm size and experience. Though the regression analysis presented later shows no discernible effect related to installer experience, other studies have found that installers reduce costs as they grow, consistent with the broader literature on "learning by doing" (Gillingham et al. 2014, O'Shaughnessy 2018). Installers may also vary in skill level and licensing, which can impact costs and pricing. In addition, some installers may specialize in systems with premium components or may undertake more-complex or customized installations, while others may tend toward more-standardized projects. Lastly, some installer-level pricing differences may simply reflect attributes of the local markets they serve, which vary in terms of competition, permitting and interconnection processes, and the various other factors identified within the preceding discussion of state-level pricing differences.



Notes: Each dot represents the median installed price of an individual installer, ranked from lowest to highest, while the shaded band shows the 20th to 80th percentile range for each installer.

Figure 26. Installer Pricing for 2018 Residential Systems

Pricing by Module Efficiency

Module efficiency can impact installed prices in countervailing ways. On the one hand, higher efficiency modules can help to reduce BoS costs, by shrinking the footprint of the system. At the

[9] The total number of firms in the dataset is likely inflated to some extent due to incomplete standardization of installer names.

[10] The extremes at either end of the curve quite likely represent reporting anomalies by individual installers. For example, the exceptionally high-priced installers may be bundling PV with other measures and reporting the total installed price for all measures combined.

same time, however, higher-efficiency modules can also be more expensive. For example, spot market prices reported through PVInsights in August 2019 were roughly $0.05/W higher for mono-crystalline PERC modules versus standard poly-crystalline modules, while prices reported through pvXchange were $0.06/W higher for "high efficiency" than for "mainstream" modules (PVInsights 2019, pvXchange 2019). These differences are but a fraction of the much greater pricing variation among individual module brands and models. For example, among just six major brands reported on PVInsights, average weekly retail prices varied over a range of more than $0.46/W from the lowest to the highest-price manufacturer—reflecting differences in not just efficiency, but other performance attributes, warranty terms, and aesthetics as well.

To illustrate the net impact on system-level prices, Figure 27 compares installed prices based on the efficiency of the modules used in each system. Differences in module efficiencies up to 20% appear to have minimal impact on net system-level pricing. Above 20%, however, system prices were markedly higher. Within the residential class, systems with module efficiencies >20% had a median price almost $0.4/W higher than those with efficiencies below that threshold. That pricing premium was even greater in the non-residential sector ($0.7/W for small non-residential and $0.9/W for large non-residential). These system-level pricing differences partly reflect underlying module pricing, as almost all of the systems in the dataset with premium efficiency modules use either SunPower or LG models with n-type mono-crystalline cells, which often sell at a substantial premium over standard mono-crystalline modules. In addition, a relatively high proportion of systems with premium efficiency modules also have microinverters, which, as discussed below, are also associated with higher installed prices.

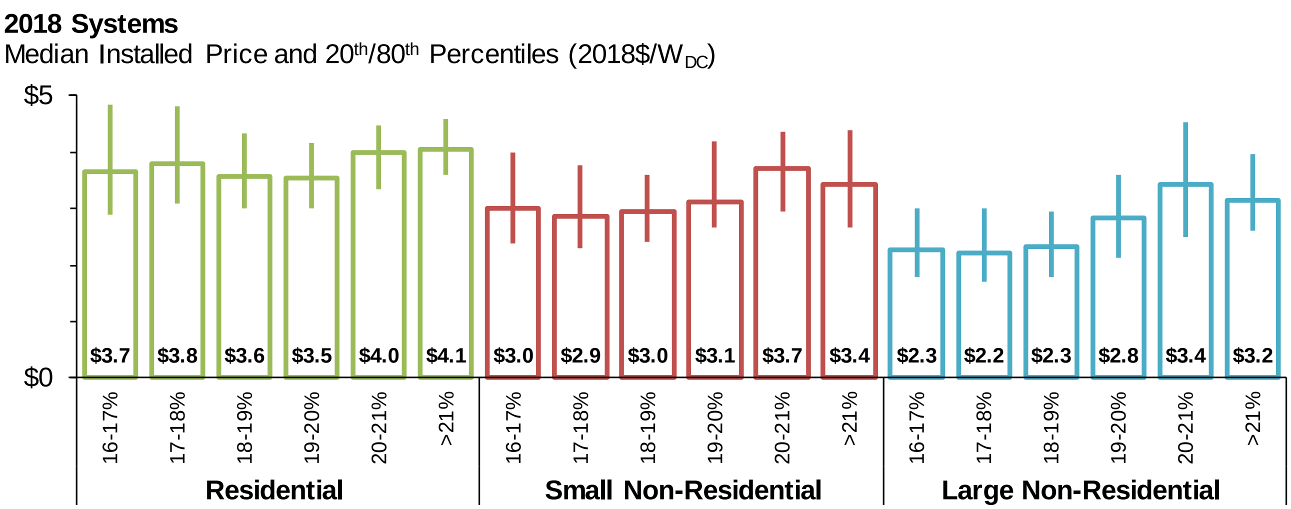


Figure 27. Installed Price Differences Based on Module Efficiency

Pricing by Inverter Type

MLPEs enhance system performance, but entail some higher up-front cost relative to standard string inverters. In 2018, prices for microinverters averaged $0.2-0.3/W higher than for standard string inverters, while DC optimizers added roughly $0.1/W (Fu et al. 2019, Wood MacKenzie and SEIA 2019). MLPEs may also affect installed prices indirectly, via impacts on installation labor, system design, and electrical balance-of-system costs.

As shown in Figure 28, installed-price differences between systems with and without MLPEs are relatively small and have not been altogether consistent over time. That said, installed-price difference in 2018 more-or-less coincide with cost premiums for each type of MLPE, noted above. Among residential systems, median installed prices for systems with microinverters were roughly $0.3/W higher, while those with DC optimizers were roughly $0.1/W higher, compared to systems with no MLPEs. Non-residential systems exhibit similar installed-price differences across inverter technologies. These results are generally consistent with the regression results presented later, though those show a slightly smaller premium for system with microinverters, and a somewhat larger one for systems with DC optimizers. These empirically estimated effects can also be compared to modeled PV cost benchmarks developed by Fu et al. (2018), which estimates roughly a $0.50/W premium for systems with microinverters—in large measure due to higher electrical BoS and installation labor costs—and a $0.05/W premium for systems with DC optimizers.

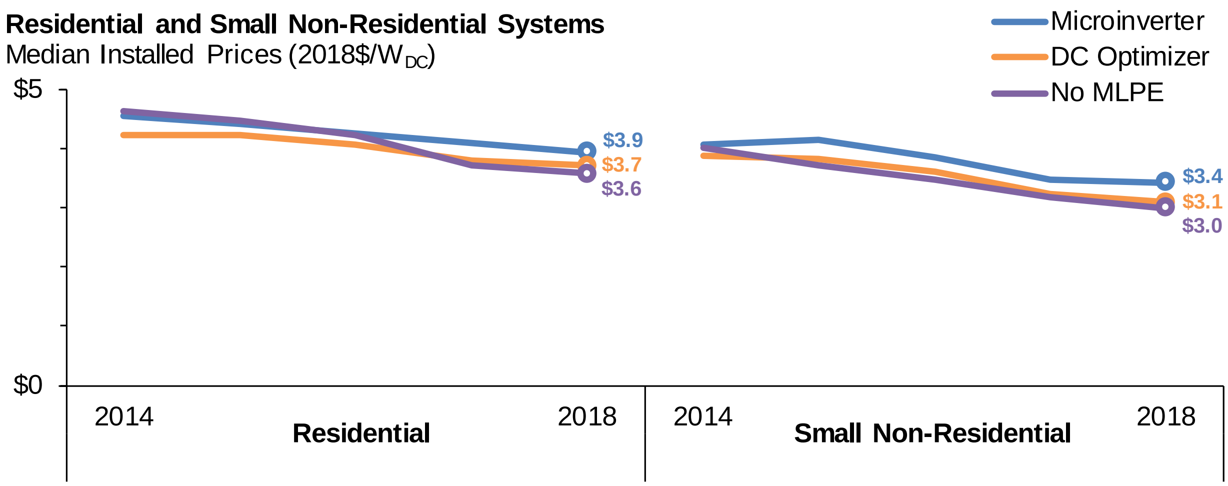


Figure 28. Installed Price Differences between Systems with and without MLPEs

Pricing for Residential New Construction vs. Retrofits

Though the vast majority of residential systems are installed as retrofits on existing homes, some are installed in new construction—often in large housing developments. Within the data assembled for this report, most of the residential new construction systems are in California, and have been funded through the state's *New Solar Homes Partnership* (NSHP) program. Those systems represent roughly 3% of all residential systems installed in California's investor-owned utilities' service territories in 2018. Going forward, that percentage is likely to rise, as a result of the state's solar home mandate that all new residential new construction starting in 2020 must include PV (subject to certain limitations).

Solar installed in new construction can benefit from economies of both scale and scope, potentially reducing its cost relative to retrofits on existing homes. Economies of scale occur specifically in the case of large new housing developments, where equipment and services can be procured in bulk, and system design and installation can be standardized and coordinated across large numbers of homes in close proximity. Customer acquisition costs for these systems may also be minimal, particularly if solar is installed as a standard feature on all homes in the developments. Economies of scope, instead, occur when particular labor or materials costs can be shared between PV installations and other elements of home construction, such as roofing and electrical work (Ardani et al. 2018).

In contrast, several other factors can lead to higher costs and prices for systems installed in new construction. First, PV systems on new homes tend to be relatively small. Within California's NSHP program, for example, the median system size in 2018 was just 3.0 kW, compared to 6.1 kW for retrofit systems in the state. New construction systems also disproportionately use premium efficiency modules (83%, compared to 25% for retrofits) and microinverters (98%, compared to 41% for retrofits), which, as the previous sections have shown, tends to increase installed prices.

On net, installed prices for new construction systems in California were higher in 2018 than for retrofit systems, as shown in Figure 29. This is true even when comparing only among 2-5 kW systems with premium efficiency modules and microinverters. These counter-intuitive results are driven by a single installer, representing more than 80% of the new construction systems, that reports prices of roughly $4.5/W for most of its systems.[11] In contrast, the regression analysis presented later, which controls for a wider set of confounding variables, finds that installed prices for new construction systems were, in fact, *lower* than for retrofits, by roughly $0.5/W on average.

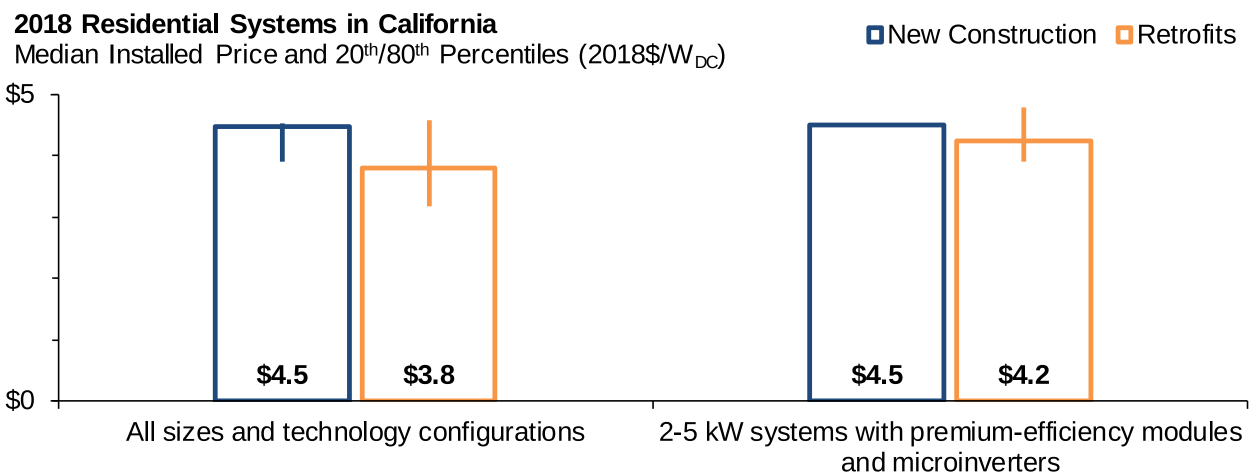


Figure 29. Installed Price of Residential Retrofit vs. New Construction in California

Pricing for Tax-Exempt vs. For-Profit Commercial Sites

As noted earlier, roughly 20% of the 2018 non-residential systems in the full data sample are at tax-exempt customer sites (i.e., schools, government buildings, and non-profit organizations, such as churches). That percentage is slightly lower in the installed-price sample (16%), given the exclusion of TPO systems, which are more prevalent among tax-exempt customers.

As shown in Figure 30, systems installed at tax-exempt customer sites are generally higher priced than those at commercial sites. These differences are consistent over time and are most pronounced among large non-residential systems. Higher prices at tax-exempt customer sites may reflect a number of underlying factors, including prevailing wage/union labor requirements, preferences for domestically manufactured components, a high incidence of shade and parking structure PV arrays, and lower borrowing costs that allow higher-priced projects to pencil-out.

[11] Two other issues with the installed-price data for new construction systems are also worth noting. First, we commonly observe that identical prices are reported for all systems within a given development, presumably because the developer purchases the set of systems as a bulk order. Second, to the extent that certain costs are shared between the PV installation and other aspects of home construction (e.g., roofing and electrical work), the entities reporting installed-price data may have some discretion in terms of how those shared costs are allocated to the PV system, which can create difficulties in making a true apples-to-apples comparison with retrofit systems.

Within the large non-residential segment, systems at tax-exempt sites also tend to be somewhat smaller than those at commercial sites; in 2018, for example, the former averaged roughly 1,100 kW in size while the latter averaged 1,800 kW.

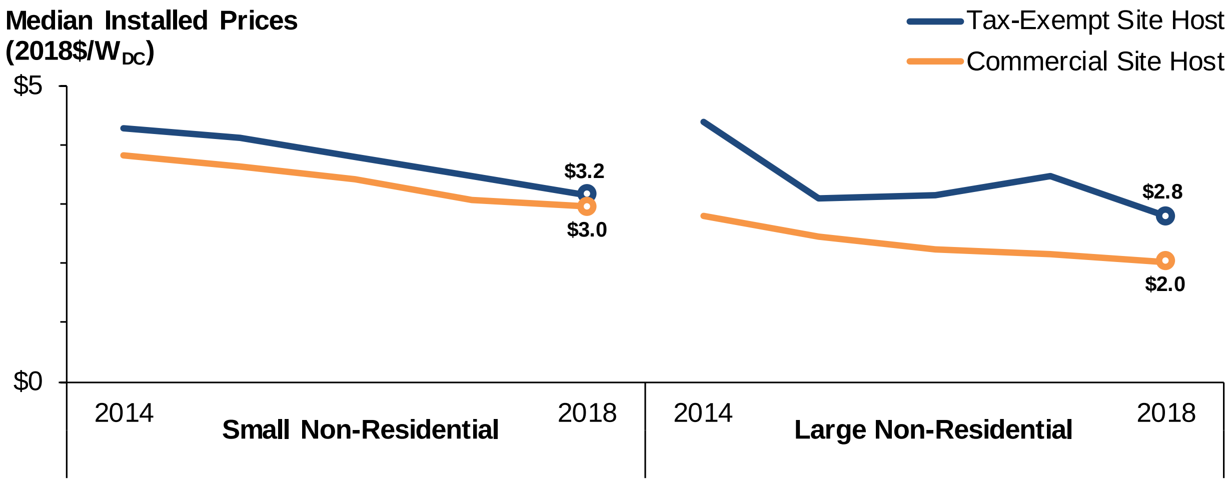
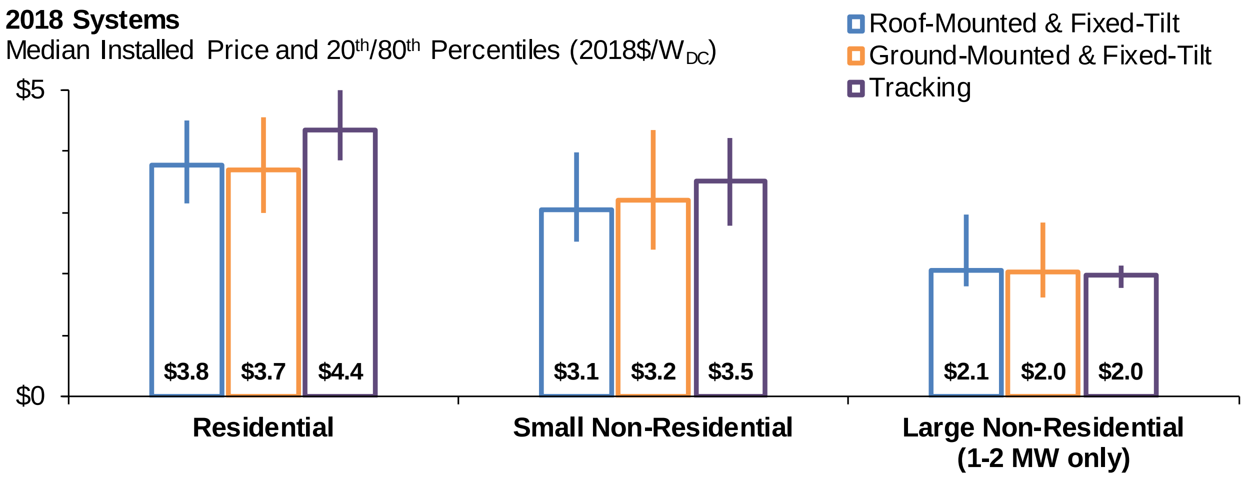


Figure 30. Installed Prices for Tax-Exempt vs. Commercial Site Hosts over Time

Pricing by Mounting Configuration

As described earlier in the report, the data sample consists mostly of roof-mounted systems, but some portion are ground-mounted, and a small fraction of those use tracking. These variations in mounting configurations may also lead to differences in up-front installed prices. This is most obvious in the case of tracking equipment, which represents an incremental hardware cost. Ground-mounting may also involve some additional up-front costs related to trenching and foundation-work, not present in the case of roof-mounted systems. To varying degrees, the additional up-front costs associated with both tracking and ground-mounting may be offset by performance gains (i.e., higher capacity factors) and, in the case of ground-mounting compared to roof-mounted systems, potentially lower ongoing maintenance costs.



Notes: The comparison among large non-residential systems focuses specifically on systems in the 1-2 MW size range, in order to maintain comparability across mounting configurations in this customer segment.

Figure 31. Installed Prices by Mounting Configuration

Focusing on just the up-front cost differences, Figure 31 compares installed prices across mounting configurations, for both residential and non-residential systems installed in 2018. The figure shows no clear or consistent difference between fixed-tilt ground-mounted and roof-mounted systems, though the regression analysis in the next section does find a fairly strong and statistically significant effect within the residential segment. The figure does show a distinct premium for systems with tracking equipment, at least within the residential and small non-residential segments, as one would anticipate. The lack of any apparent effect among large non-residential systems is likely just an artifact of the small underlying sample sizes and the presence of other, more significant confounding factors. As one point of reference, bottom-up engineering cost models of utility-scale PV generally suggest about a $0.1/W premium for systems with tracking (Fu et al. 2018, Wood Mackenzie and SEIA 2019).

Multi-Variate Regression Analysis of 2018 Residential System Prices

The preceding comparisons of installed prices across various sub-segments of the PV dataset help to reveal some of the key drivers for PV pricing variation. As highlighted within that discussion, however, those comparisons can be obscured or distorted as a result of correlations among various pricing drivers. In order to better control for those correlations, this section presents the results of a multi-variate regression analysis that accounts for these inter-relationships and more accurately identifies the effects of individual installed-price drivers.

This statistical model is based largely on previous econometric analysis of the *Tracking the Sun* dataset (Gillingham et al. 2014; Nemet et al. 2017; O'Shaughnessy 2019). The model can be summarized by the following equation:

$$p = \alpha + system\beta_1 + market\beta_2 + installer\beta_3 + S + Q + \varepsilon_i$$

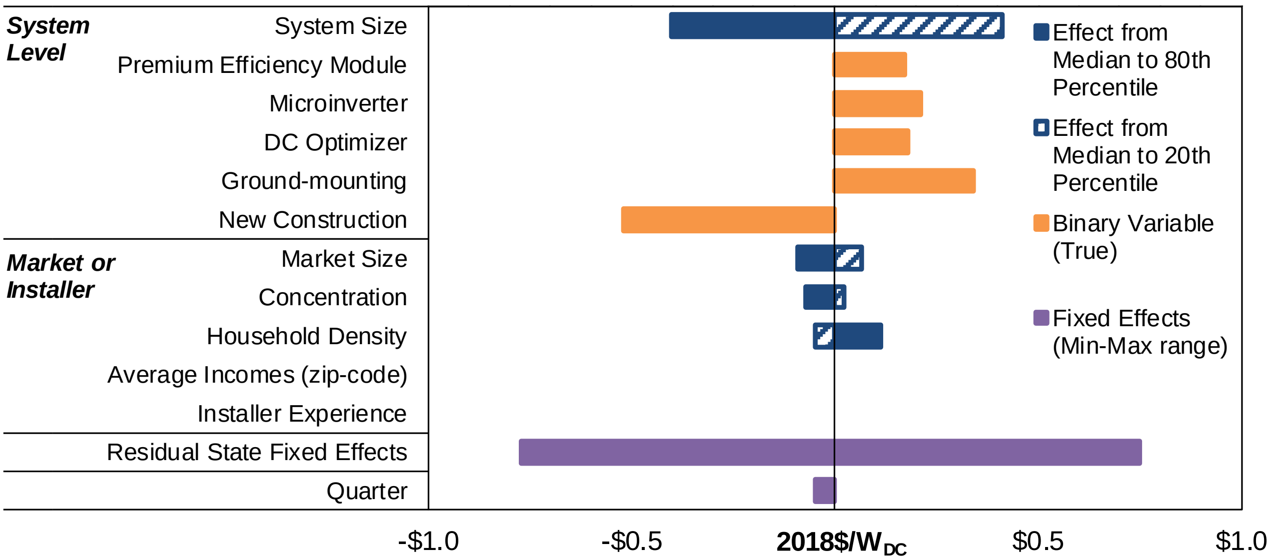
where:

- p is the system price
- The terms *system*, *market*, and *installer* represent vectors of system-, market, and installer-level variables, respectively; the terms β represent the numeric effects of those variables on prices
- S is a state fixed effect; it measures the average price difference by state after controlling for all the other factors in the model
- Q is a quarterly fixed effect; it measures the average price difference by quarter after controlling for all other factors

We estimate the model based on 2018 residential systems from the installed-price dataset, though the full dataset is used to generate some of the variables. Appendix C provides additional methodological details.

Figure 32 below summarizes the effects of each variable on installed prices. As explained in the notes below the figure, the interpretation for each variable depends on whether it is a continuous variable (such as system size), a binary variable (such as module or inverter type), or a fixed-effects variable (state and quarter). Appendix C also includes the full set of regression results, presented in a more standard fashion, in terms of individual variable coefficients and standard errors.

Focusing first on the system-level variables, the results show quite substantial effects related to system size, with roughly an $0.8/W difference in average prices between the 20th and 80th percentile values for system size. This is slightly larger than the $0.6/W difference in median prices shown by the earlier descriptive analysis. As with the descriptive analysis, the regression analysis also shows clear diminishing returns to scale. For example, though not shown in Figure 32, the regression model coefficients indicate that increasing system size from 5 kW to 10 kW would result in a price reduction of $0.75/W, but increasing system size further from 10 kW to 15 kW would result in just a $0.25/W price reduction.



Notes: For continuous variables, the figure shows the effect on system prices associated with moving from the median to the 20th and 80th percentile values of those variables. For binary variables, the figure shows the effect if that binary variable is true, and for fixed effects variables, the figure shows the range between the minimum and maximum effect of the variables in each set.

Figure 32. Impact of Modeled Variables on Installed Prices

The model results for the various component-related variables are all directionally consistent with the earlier descriptive analysis, though differ in magnitude. In particular, the model results suggest that prices are $0.2/W higher for systems installed with premium modules (vs. the $0.4/W difference from the simple comparison of medians), $0.2/W higher for systems with microinverters (vs. $0.3/W from the descriptive analysis), and $0.2/W higher for systems with DC optimizers (vs. $0.1/W from the descriptive analysis). The descriptive comparisons may be amplified due to strong overlap between systems with premium efficiency modules and microinverters, whereas the econometric model is able to separately parse out the incremental effects of each.

The coefficients for the system variables related to ground-mounting and new construction are both intuitive but contrast with the earlier descriptive comparisons. For ground-mounted systems, the model estimates that prices were $0.3/W higher, on average, than prices for rooftop systems. This effect is plausible, given the additional site preparation costs, but was not apparent earlier in Figure 31, when simply comparing median values between a relatively small number of residential ground-mounted systems and a vastly larger number of rooftop systems.

For systems installed in new construction, the econometric model estimates that prices were lower, by $0.5/W on average, compared to retrofit systems. This result is, again, intuitively plausible—given the economies of scope and scale that arise in new construction (Ardani et al. 2018, O'Shaughnessy and Margolis 2018)—but contrasts markedly with the descriptive results. Those earlier results showed that median prices for new construction systems were *higher* than for retrofits, by $0.7/W overall and by $0.3/W if comparing only among relatively small systems with premium efficiency modules and microinverters. In this case, the discrepancy between the simple descriptive comparison and the economic model is partly due to the additional controls included in the econometric model, but is also due to peculiar features of the underlying pricing distribution for new construction systems. That distribution has several large spikes, which result in a substantially higher median price (as used in the earlier descriptive analysis) than the average price (as used implicitly in the econometric model).

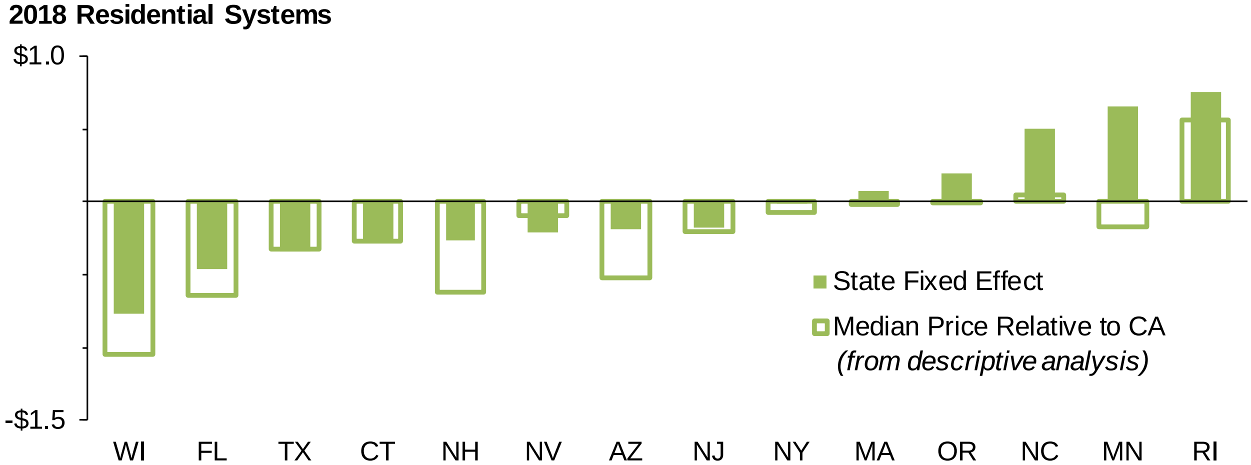
The results for the various market- and installer-level variables generally show relatively small impacts on system prices, compared to the effects of the system-level variables. That said, they nevertheless reveal some interesting, and potentially counterintuitive, results. Among other things, these results show that, after controlling for other factors, prices do tend to be lower in larger markets, which contrasts with the earlier descriptive results. Prices also tend to be higher in markets with greater housing density (e.g., in more urbanized areas, which often have a higher cost of living). The model results also show no statistically significant effect related to average incomes within a given market.

The results related market concentration and installer experience are both somewhat counterintuitive, but explainable. The results indicate that prices tend to be lower in more concentrated markets, whereas the general expectation might be for prices to be higher in those markets, due to greater market power. At the same time, the results also suggest that installer experience has no statistical impact on prices. This contrasts with previous studies (Gillingham et al. 2014 and O'Shaughnessy 2019), which show that installers with more experience tend to have lower prices, as a result of learning-by-doing and economies of scale. These seemingly counter-intuitive results reflect a competing dynamic between market concentration and installer experience, as more competition generally implies that installers operate at smaller scales, and small-scale installers tend to be less efficient. Prices therefore tend to be lowest in markets with some optimal balance of competition and installer scale. O'Shaughnessy (2019) provides a more comprehensive discussion of these competing effects.

Finally, the state-level fixed effects represent the "residual" pricing variation across states, after controlling for the various system- and market-level variables discussed above. As indicated by the results presented in Figure 32, those state-level effects are quite substantial, with roughly a $1.5/W range across states. These residual pricing differences reflect other (unobserved) pricing drivers that vary across states but are not explicitly modeled—for example, differences related to permitting, interconnection, incentives, or housing stock.

Figure 33 provides additional detail on these state fixed-effects. The values refer to average pricing differences *relative to California*, after controlling for other pricing drivers. For example, the results indicate that, on average, systems are about $0.8/W less expensive in Wisconsin and about $0.8/W more expensive in Rhode Island, than in California. The figure also shows the difference in median prices between each state and California, based on the earlier descriptive analysis. In some cases, the descriptive results coincide quite closely with the results of the regression analysis, while in other cases, the two sets of results differ substantially. For example, the fixed-effects for New Hampshire and Arizona are considerably smaller than what the simple descriptive analysis showed, indicating that the difference in medians relative to California is largely related to other factors captured in the regression analysis. Conversely, in states such as

North Carolina and Minnesota, the fixed effects are much larger (and may even point in a different direction) than the simple difference in medians, suggesting that other, un-modeled pricing drivers are dampening the apparent pricing differences across states.



Notes: A number of states contained within the larger data sample were omitted from the multi-variate regression analysis if missing one or more key data fields

Figure 33. State Fixed-Effects from Regression Analysis Compared to Descriptive Analysis

6. Conclusions

The number of PV systems installed in the United States has grown at a rapid pace in recent years, driven both by declining costs and supportive policies. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage further cost reductions over time through increased deployment. Research and development (R&D) efforts within the industry have also focused on cost reductions, led by the U.S. DOE's Solar Energy Technologies Office, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020, and by an additional 50% from the 2020 goal by 2030.

Available evidence confirms that the installed price of PV systems (i.e., the up-front cost borne by the PV system owner, prior to any incentives) has declined substantially since 2000, though both the pace and source of those cost reductions have varied over time. Following a period of relatively steady and sizeable declines, installed price reductions began to stall around 2005, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Beginning in 2008, however, global module prices began a steep downward trajectory, and those module price reductions were the driving force behind the decline in total system prices for PV from 2009 through 2013. Since then, installed prices have continued to fall, but at a much slower pace, reflecting continued, but gradual, reductions in both hardware and soft costs.

Given the limits to further reductions in module and other hardware component prices, continued reductions in soft costs will be essential to driving further deep reductions in installed prices. Unlike module prices and other hardware component costs, which are primarily established through global and national markets, soft costs may be more readily affected by local policies—including deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. While the data presented within this report suggest that soft costs have fallen significantly over time, lower installed prices in other major international markets (e.g., see Seel et al. 2014), as well as the wide diversity of observed prices within the United States, suggest that broader soft cost reductions are possible.

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Appendix A: Additional Details on the Data Sample

Table A-1. Sample Summary by Data Provider

State	Data Provider	2018 Systems (No. of Systems)		All Years (No. of Systems)	
		Full Sample	Installed-Price Sample	Full Sample	Installed-Price Sample
AR	Arkansas Energy Office	0	0	105	97
AZ	Ajo Improvement Company	0	0	3	3
	Arizona Public Service	15,104	4,584	90,110	20,456
	Duncan Valley Electric Coop.	0	0	7	1
	Mohave Electric Coop.	36	36	645	643
	Morenci Water & Electric	0	0	3	3
	Navopache Electric Coop.	0	0	141	128
	Salt River Project	1,968	1,554	19,496	8,319
	Sulpher Springs Valley Electric Coop.	0	0	1,471	1,169
	Trico Electric Coop.	47	43	2,001	1,060
	Tucson Electric Power	4,533	3,671	21,656	11,738
	UniSource Electric Services	498	482	3,469	2,688
CA	California Center for Sustainable Energy (Bear Valley Electric)	0	0	123	25
	California Center for Sustainable Energy (Pacific Power)	0	0	205	130
	CPUC and CEC (Currently Interconnected Dataset, CSI, NSHP, ERP, SGIP) [a]	128,648	68,195	834,429	341,823
	City of Palo Alto Utilities	0	0	940	547
	Imperial Irrigation District	0	0	4,162	1,450
	Los Angeles Dept. of Water & Power	3,988	2,733	34,963	13,800
	Sacramento Municipal Utility District	4,611	0	24,368	4,171
CO	Xcel Energy	6,222	4,797	46,965	23,677
CT	Clean Energy Finance and Investment Authority	4,665	1,077	29,220	8,553
	Public Utilities Regulatory Authority	193	0	796	0
DC	Washington D.C. Public Service Commission	774	0	4,252	0
DE	Department of Natural Resources and Environmental Control	154	153	2,795	2,567
FL	Florida Energy & Climate Commission[b]	0	0	1,256	1,201
	Gainesville Regional Utilities[b]	108	105	679	658

	Orlando Utilities Commission[b]	458	356	1,200	1,009
IL	Dept. Commerce and Economic Opportunity	0	0	1,463	1,386
MA	Massachusetts Clean Energy Center and Dept. of Energy Resources[c]	10,805	5,751	90,037	39,284
MD	Maryland Energy Administration	2,435	2,416	13,984	11,034
ME	Efficiency Maine	0	0	531	526
MN	Dept. of Commerce	185	183	1,876	1,674
	Xcel Energy	659	642	2,636	2,287
MO	Ameren	76	0	4,012	0
	Kansas City Power and Light	283	0	3,760	0
NC	NC Sustainable Energy Association	2,528	2,449	9,957	9,336
NH	New Hampshire Public Utilities Commission	1,238	888	6,543	5,382
NJ	New Jersey Board of Public Utilities	16,263	4,240	104,650	24,148
NM	Energy, Minerals & Natural Resources Dept.	0	0	7,679	7,282
	Public Service Company of New Mexico	2,876	0	10,436	0
NV	NVEnergy	8,859	3,160	32,580	7,046
NY	New York State Energy Research and Development Authority	10,686	5,442	89,016	42,741
OH	Ohio Public Utilties Commission	67	0	2,666	0
OR	Energy Trust of Oregon[d]	1,778	1,430	14,384	9,643
	Oregon Dept. of Energy[d]	1	1	4,133	3,349
	Pacific Power	1	1	832	709
PA	Dept. Community and Economic Development	0	0	55	51
	Dept. of Environmental Protection	0	0	7,078	7,039
	Sustainable Development Fund	0	0	201	200
RI	National Grid & Rhode Island Commerce Commission	1,728	1,132	5,802	3,819
TX	Austin Energy	1,067	951	7,379	7,142
	CPS Energy	3,077	3,051	13,761	13,695
	Clean Energy Associates (El Paso Electric)	0	0	369	333
	Clean Energy Associates (Entergy)	0	0	57	55
	Clean Energy Associates (Oncor Electric Delivery Company)	0	0	908	692
	Clean Energy Associates (Sharyland Utilities)	0	0	6	6
	Clean Energy Associates (Southwestern Electric Power Company)	0	0	39	39
	Clean Energy Associates (Texas Central Company)	36	36	245	241
	Clean Energy Associates (Texas New Mexico Power Company)	0	0	23	21
	Clean Energy Associates (Texas North Company)	30	30	125	122

UT	Office of Energy Development	1,282	1,258	21,052	20,751
VT	Vermont Energy Investment Corporation & Energy Action Network	2,134	0	12,483	3,453
WA	Washington State University & Puget Sound Energy	5,134	5,010	12,231	7,784
WI	Focus on Energy	844	843	4,039	4,001
Total		**246,079**	**126,700**	**1,612,488**	**681,187**

[a] Data for California's three large investor owned utilities (PG&E, SCE, and SDG&E) are developed by merging the CPUC's Currently Interconnected Data Set with data from the various incentive programs that have been or are currently offered in the utilities' service territories. See Appendix A for more details on this merging process.

[b] A small number of PV systems that received an incentive through the Florida Energy & Climate Commission (FECC)'s statewide solar rebate program also participated in one of the Florida utility programs. Those systems were retained in the data sample for the utility programs and removed from the sample for FECC's program. The values shown here for FECC reflect the residual sample, after overlapping systems were removed.

[c] Separate datasets, consisting of largely overlapping sets of systems, were provided by the Massachusetts Clean Energy Center (MassCEC) and the Dept. of Energy Resources (DOER). These two datasets were merged, with overlapping systems identified based primarily on the PTS ID numbers provided in the two datasets.

[d] Oregon systems that received incentives through both the Oregon Dept. of Energy's tax credit program and the Energy Trust of Oregon were retained in the data sample for the Energy Trust and removed from sample for the Dept. of Energy. The values shown here for the Oregon DOE reflect the residual sample, after overlapping systems were removed.

Appendix B: Data Cleaning and Standardization

To the extent possible, this report presents data as provided directly by PV incentive program administrators and other data sources; however, several steps were taken to clean and standardize the data.

Conversion to 2018 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2018 dollars (2018$). Data provided by PV program administrators in nominal dollars were converted to 2018$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to Direct Current (DC) Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most data providers directly provide system capacity in units of DC-STC; however, several did not. In those cases, PV system DC-STC capacity could generally be calculated from the nameplate rating of the modules and module quantity. Of particular note, that latter procedure was applied to all systems in the CPUC's Currently Interconnected Dataset, as the DC system sizes reported in that dataset were determined to generally not reflect STC ratings (but, instead, may reflect DC output under PV-USA test conditions, which differ from STC). Where module manufacturer or quantity data were unavailable, utility-specific adjustment factors were applied to the reported DC ratings.

Identification and Treatment of Duplicate Systems: For a number of states (California, Florida, Massachusetts, Oregon, Rhode Island, and Vermont), data provided by multiple different entities contain overlapping sets of systems. In addition, data provided by some entities includes multiple records for the same address—for example, where individual arrays or project phases are each submitted under a separate application. In order to avoid double-counting, duplicate observations were merged or eliminated, and multi-phase projects were consolidated. These instances were identified using, wherever possible, a common ID number across datasets or customer street address. In cases where neither of those pieces of information were available, more-aggressive measures were taken to identify and eliminate duplicates.

California Data Integration: The CPUC's Currently Interconnected Dataset (CID) was used as the base dataset for California's investor-owned utilities, and additional data for those systems were incorporated from the various incentive program datasets (CSI, NSHP, SGIP, and ERP). Matching systems across datasets was based on a CSI ID numbers, if available; otherwise, street addresses were used. As a general rule, data from the CID were retained as-is, and data from the incentive programs were integrated only in instances where the CID was missing data within a particular field or simply did not contain that field. There were, however, several key exceptions to that general rule. The first, as noted previously, is that system sizes were re-calculated based on reported module models and quantities. The second exception occurred in the case of multi-phase projects, where the reported installed cost is assumed to reflect only the final project phase, but the system size reflects the sum total across all phases. In those instances, the installed cost is assumed to be unavailable within the CID. Finally, in cases where installed price is unavailable in the CID but available from one of the incentive program datasets, not only is the installed price data integrated from the incentive program (replacing a null value), but the system size and installation date are over-written as well, in order to maintain internal consistency across those three key fields.

Incorporating Data on Module and Inverter Characteristics. The raw data provided by PV incentive program administrators generally included module and inverter manufacturer and model names. We cross-referenced that information against public databases of PV component specification data (namely, the CSI eligible equipment lists[12] and SolarHub[13]) to characterize the module efficiency, module technology type

[12] http://www.gosolarcalifornia.ca.gov/equipment/
[13] http://www.solarhub.com/

(mono-crystalline vs. poly-crystalline vs. thin-film), and inverter technology (microinverter vs. string/central inverter). All systems with SolarEdge inverters were assumed to also be equipped with DC power optimizers.

Identification of Customer Segment: Almost all programs provided some explicit segmentation of host customers, at least into residential and non-residential customers. In the rare cases where even this minimal level of segmentation was not provided, systems less than or equal to 20 kW in size were assumed to be residential, and those larger than 20 kW were assumed to be non-residential. The choice of this threshold was based on an inspection of data where customer segmentation was available, and is roughly the value that minimizes the error in these assignments to customer segments.

Identification of Host-Owned vs. TPO Systems: Most programs explicitly identify the ownership type of each system as either host-owned or TPO. Where such data were not provided, however, systems were assumed to be host-owned under any of the following conditions: (a) the system was installed in a state where TPO was not allowed at the time of installation, (b) the system was installed in a state where TPO is technically allowed but actual market activity is known to be quite low, or (c) the PV incentive program providing data is not available to TPO systems.

Identification of Self-Installed Systems: Self-installed systems were identified in several ways. In some cases, these systems could be identified based on the reported installer name (e.g., if listed as "owner" or "self"). In addition, all systems installed by Grid Alternatives or Habitat for Humanity were treated as self-installed, as these entities rely on volunteer labor for low-income solar installations.

Calculation of Net Present Value of Reported PBI Payments: A number of PV incentive programs in the data sample provided performance-based incentives (PBIs), paid out over time based on actual energy generation and a pre-specified payment rate, to some or all systems. In order to facilitate comparison with up-front rebates provided to the other systems in data sample, the net present value (NPV) of the expected PBI payments were calculated based on an assumed 7% nominal discount rate.

Appendix C: Statistical Addendum

In this addendum we provide additional details behind the econometric model presented in this report.

Dataset

The model data sample comprises 102,223 residential customer-owned systems from the analysis dataset. We drop non-residential and all TPO systems. Our logic for dropping the TPO systems is described in depth in O'Shaughnessy (2019). Briefly, dropping the TPO systems improves the interpretability of the model's coefficients and removes potential bias due to inherent differences between customer-owned and TPO systems.

Variable Selection and Estimation

Our selection of variables was based largely on other TTS-based models (Gillingham et al. 2014, Nemet et al. 2016b, and O'Shaughnessy 2019). Table C-1 identifies the included variables and their sources. Most of the variables are present in, or can easily be derived from, the *Tracking the Sun* (TTS) dataset.

HHI: Market concentration is the degree to which market shares are disproportionately held by an industry's large companies. A market where large companies hold a disproportionately high market share is said to be concentrated. The Herfindahl-Hirschman Index (HHI) is the most common metric for market concentration. HHI is equal to the sum of squared market shares over some defined time period. The most concentrated market is one where HHI = 1, which represents a monopoly. HHI approaches zero as market shares become more evenly distributed among a larger number of firms.

Our estimation of HHI follows the methodology developed in O'Shaughnessy (2019). For every system the customer's market is defined as the set of zip codes that fall within a 20 km radius around the customer's zip code. Market shares are estimated for every installer that installed at least one system in that market in the year preceding the system's installation date. Note that the estimation of market shares is based on the full dataset—it includes all systems dropped for analysis purposes (e.g., TPO) and includes systems installed in 2017.

Market Size: Market size is equal to the aggregate number of systems installed in the customer's market based on the full dataset. The market is defined under the same approach as described for HHI: the set of zip codes falling within a 20 km radius around the customer's zip code (O'Shaughnessy 2019).

Installer Experience: For a given system i, installer experience is equal to the aggregate number of systems installed by the installer associated with system i as of the date that system i was installed. Consistent with Gillingham et al. (2014), we assume that recent experience is more relevant than past experience and depreciate the experience variable at 20% per quarter.

Premium Modules: The PV module market comprises a broad mix of products with various characteristics. The actual or perceived quality of certain modules may contribute to differences in system prices. Previous studies have used module efficiency as a proxy for module quality (Nemet et al. 2016b, O'Shaughnessy 2019). While module efficiency may indicate module quality, it is unlikely that a linear relationship exists between percentage points of efficiency and perceived or actual quality and their effects on prices. Anecdotal evidence suggests that high-efficiency modules also tend to have other premium characteristics such as longer warranties. As a result, we instead use a dummy variable for "premium" modules, where premium refers to any module with at least 20% efficiency.

Table C-1. Regression Variable Definitions and Sources

Variable	Definition	Source
System		
kW	System capacity in kW	TTS
kW^2	Squared term of system capacity	TTS
Premium modules	Dummy variable indicating whether system uses a premium-efficiency module	TTS
Microinverter	Dummy variable indicating whether system uses a microinverter	TTS
DC optimizer	Dummy variable indicating whether system uses a DC optimizer	TTS
Ground-mounting	Dummy variable indicating a ground-mounted PV system (groundmount=1, rooftop=0)	TTS
New construction	Dummy variable indicating if system was installed during new construction (new construction=1) or as a retrofit installation on an existing home (new construction=0)	TTS
Market		
HHI	Metric of the degree to which market shares are skewed toward larger firms	Calculated
HHI^2	Squared term of HHI	Calculated
Market size	Number of systems installed in the customer's market in 2018	Calculated
Installer experience	Cumulative number of systems installed by the installer as a proxy for installer experience, depreciated at 20% per quarter	Calculated
Household density	Number of households per square mile in customer's market	U.S. Census
Median income	Median household income in customer's zip code	U.S. Census

Model Limitations

There are two noteworthy limitations of TTS-based regression models, including the model presented in this report. First, the model is limited to observed variables as reported to TTS or derivable from other reliable sources such as U.S. Census data. There are numerous unobserved variables that affect system prices but are excluded from the model, such as rooftop characteristics and home electrical wiring characteristics. Second, the geographic representation of the model is limited to states and utility service territories that report data to TTS. As a result, the results do not necessarily represent price drivers in key markets such as Hawaii that do not report data to TTS.

Complete Regression Results

Table C-2 presents the complete regression results, in terms of the coefficient and standard error for each variable. As shown, virtually all variables are significant at the 99% level. In general, these results are consistent with those from previous models in Gillingham et al. (2014) and O'Shaughnessy (2019).

Table C-2. Complete Regression Results

Variable	Coefficient	SE
System size	-0.30*	0.01
System size squared	0.01*	0.00
Premium module	0.17*	0.01
Microinverter	0.21*	0.01
DC optimizer	0.18*	0.01
Groundmount	0.34*	0.02
New Construction	-0.52*	0.03
HHI	-1.44*	0.11
HHI^2	1.15*	0.15
Market size (x1000)	-0.09*	0.00
Installer experience (x1000)	0.00*	0.00
Households per sq. mi (x1000)	0.10*	0.00
Median income (x1000)	0.00*	0.00
AZ	-0.19*	0.01
CT	-0.27*	0.04
FL	-0.46*	0.06
MA	0.08*	0.02
MN	0.66*	0.10
NC	0.50*	0.03
NH	-0.26*	0.04
NJ	-0.18*	0.02
NV	-0.21*	0.02
NY	-0.01	0.02
OR	0.20*	0.03
RI	0.75*	0.04
TX	-0.34*	0.02
WI	-0.77*	0.05
Q2	-0.05*	0.01
Q3	-0.04*	0.01
Q4	-0.05*	0.01
Intercept	5.40*	0.03
R^2	0.15	

* Statistically significant at $p<0.01$

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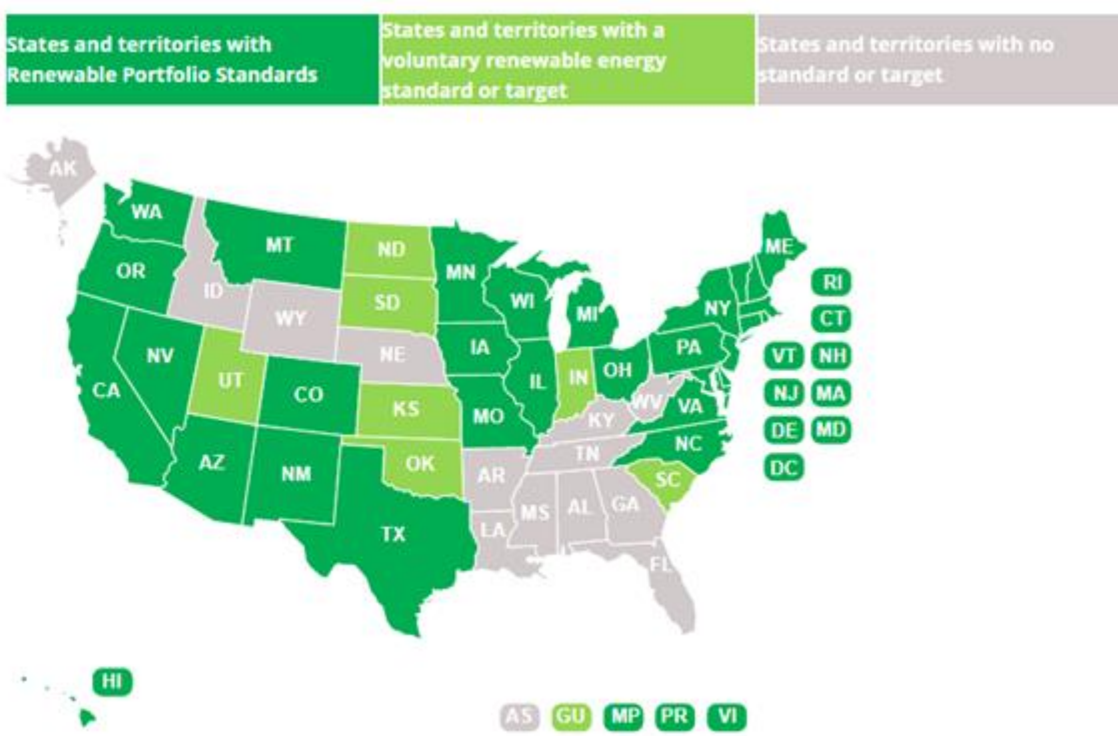
8. Refer to the Application, Volume I, Appendix G, page 6. Of the states with similar irradiation to Kentucky, explain and list the states that have renewable energy portfolio standards or mandates from regulators and which do not.

RESPONSE: A map and listing of the states with renewable portfolio standards is provided by the National Conference of State Legislatures at https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. A copy of that map is shown below. Of the states mentioned on page 6 as having similar irradiation to Kentucky but high rankings, all of them (New Jersey, Massachusetts, New York and Maryland) have renewable energy portfolio standards in place.



WITNESS: David Loomis

9. Refer to the Application, Volume I, Appendix G, page 8. Provide an explanation of NREL's Jobs and Economic Development Impacts (JEDI) modeling methodology and whether and how it differs from IMPLAN modeling methodology.

RESPONSE: Although the JEDI model is mentioned on page 8, a fuller description of the model and its relationship to IMPLAN is found on page 33 of Appendix G. "The JEDI PV Model is an input-output model that measures the spending patterns and location-specific economic structures that reflect expenditures supporting varying levels of employment, income, and output." (p.33) The JEDI model is built upon the framework of the IMPLAN modeling methodology and uses IMPLAN multipliers in its calculations.

WITNESS: David Loomis

10. Refer to the Application, Volume I, Appendix G, pages 8–9. Regarding the literature review, explain whether the touted economic benefits of the various hypothesized solar projects are net benefits and take into account the negative economic consequences of environmental or market forces upon the local electric utility and energy sectors.

RESPONSE: The literature cited on pages 8-9 generally measures the gross benefits and does not account for hypothesized environmental or market forces upon the local electric utility or energy sectors to derive a net benefit. My analysis follows this standard practice for such studies. As stated on page 33 of Appendix G, "This study analyzes the gross jobs that the new solar energy project development supports and does not analyze the potential loss of jobs due to declines in other forms of electric generation."

WITNESS: David Loomis

11. Refer to the Application, Volume I, Appendix G, Table 1, page 12. Provide the data sources behind the table and explain how IMPLAN was used to populate the table.

RESPONSE: IMPLAN provides employment numbers listed in Table 1 on page 12 and the percentages were calculated from that data. IMPLAN provides employment for each of its 546 sectors but we used IMPLAN 2 Digit NAICS 546 to aggregate the employment categories to a more reasonable number. From the IMPLAN website, they state, "Employment in IMPLAN is an Industry-specific mix of full-time, part-time, and seasonal employment. It is an annual average that accounts for seasonality and follows the same definition used by the BLS and BEA." https://implanhelp.zendesk.com/hc/en-us/articles/115009668668-Employment

WITNESS: David Loomis

12. Refer to the Application, Volume I, Appendix G, page 20. Provide a copy of the articles by Paul Gottlieb, Franscis et al., and Dwight Lee referenced in the first two paragraphs.

RESPONSE: Copies of these three articles are attached. Please note that there is a typo in the report and the second reference should read Francis et. al.

WITNESS: David Loomis

13. Refer to the Application, Volume I, Appendix G, page 21. Provide a copy of the Gottlieb 2015 article referenced in the first paragraph.

RESPONSE: This article is the same one provided in response to question 12.

WITNESS: David Loomis

CHOICES
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AAEA Agricultural & Applied Economics Association

Is America Running Out of Farmland?

Paul D. Gottlieb

JEL Classifications: Q15, Q39, R12, R14
Keywords: Farmland Availability, Farmland Preservation, Nonrenewable Resources, Urban Development, Urban Sprawl

In 1981, the inter-agency National Agricultural Lands Study (USDA and CEQ, 1981) triggered a vigorous debate about the disappearance of American farmland. Although the dire predictions of the 1981 study—it projected a need for 77 million additional agricultural acres by the year 2000—did not come true, a recent article by Francis et al. (2012), shows that the more alarmist view about farmland that was common in the 1970s and 1980s is alive and well.

Francis and his co-authors argue that we face farmland challenges today that we did not have to deal with 40 years ago. Although they ignore some reasons for optimism, such as increases in yields from genetically-modified seeds, there is little doubt that most 21st century trends affecting the long-run availability of farmland are troubling ones. A list of such trends would include global demand side pressures--international development and greater consumption of land-intensive meat products and the perpetual concern over global population growth—and global supply side pressures—environmental degradation, climate change, alternative use of land for biofuels, and diminishing returns from traditional cross-breeding technologies. Regarding urbanization, the threats of sprawl continue and its potential to pave over especially productive farmland that is located near sites of original colonial settlement with favored floodplains and well-watered, flat soils near water transportation. The local food movement has brought new opportunities for farming that are close to, and in some cases entirely within, urbanized areas. This social trend was not foreseen at the time of the 1981 Agricultural Lands Study. It offers some hope for the preservation of high-quality agricultural land, provided that: (1) it allows farmers to outbid developers for at least some urban parcels that would otherwise have been developed or (2) it adds previously developed land, such as distressed properties in central cities, to the agricultural land base and proves that farming can take place efficiently there.

State and local farmland preservation programs, as well as the federal Farm and Ranch Lands Protection Program of 1996, were designed largely to protect farmland resources from urban encroachment, following the call to action of the 1981 agricultural lands study. What has been learned about the relationship between urban expansion and long-run farmland availability in the United States? Has the threat posed by development changed over the last thirty years? The short answer is that the threat to America's agricultural land base from development remains long-term and speculative rather than urgent. Where domestic food supply is concerned, issues like water supply and soil erosion are more pressing. Agricultural markets continue to be characterized by long distance shipping, while the price and use of suburban parcels is determined today by local factors, especially the demand for urban uses.

None of this is to say that state and federal policy makers should not plan for extreme contingencies, like those related to climate change or a sharp increase in transportation costs. State and local policy makers, meanwhile, will continue to respond to local voter demands for open space, sprawl control, and maintenance of a land reserve for local agriculture.

Urbanization and Prime Farmland

The most commonly used definition of high quality agricultural land in the United States is the prime farmland

AAEA-0715-102

category of the U.S. Department of Agriculture's Natural Resources Conservation Service (NRCS). Prime farmland is defined by the NRCS as land that "has the combination of soil properties, growing season, and moisture supply needed to produce sustained high yields of crops in an economic manner if it is treated and managed according to acceptable farming methods" (USDA, 2014). By this definition, 23% of the non-federal open land in the continental United States qualified as prime farmland in 2010, whether or not it was used to grow crops (USDA and ISU, 2013).

Although the prime farmland designation is widely used to measure land that deserves the highest-priority protection, it should be remembered that land classifications are not immutable—poorer land can become "prime" when irrigated— and there is considerable local and regional variation within the prime category.

Vining, Plaut, and Bieri (1977) confirmed that prime farmland was disproportionately located in or near the nation's largest metropolitan areas, although they described the relationship as "modest." These authors observed large differences, however, in the co-location of prime farmland and urban settlement across U.S. census regions. This means that the loss of prime farmland to urbanization could be far worse in New Jersey than, say, Georgia—even if population growth rates were the same. Of course, state population growth rates are not the same. This fact must also be taken into account when analyzing—or forecasting—the loss of prime farmland in different parts of the country.

Table 1. Decline of nonfederal land currently in or available for agriculture: Prime farmland, all rural land, and land not forested

		Percentage decline in land area (10-year average 1982-2010)			
		Percentage of usable open land that is prime farmland	Prime farmland	Rural open land	Non-forested open land
Continental United States		23.3%	-1.6%	-1.3%	-1.8%
Mid-Atlantic region					
	New Jersey	22.5%	-10.8%	-8.0%	-13.7%
	Pennsylvania	14.8%	-4.5%	-2.4%	-6.7%
Great Lakes region					
	Ohio	52.8%	-2.4%	-2.1%	-3.0%
	Michigan	26.1%	-2.2%	-1.8%	-4.0%
Southeast region					
	Alabama	22.4%	-3.0%	-1.8%	-6.3%
	Georgia	23.7%	-2.6%	-2.9%	-9.2%
Plains region					
	Iowa	55.1%	-0.4%	-0.4%	-0.4%
	South Dakota	14.6%	-0.7%	-0.2%	-0.2%
Southwest region					
	Arizona	1.6%	-14.2%	-0.8%	-0.5%
	New Mexico	0.3%	-11.5%	-0.2%	-0.3%
Mountain region					
	Idaho	16.8%	-3.1%	-0.8%	-1.0%
Pacific region					
	California	12.2%	-4.7%	-2.5%	-3.0%

Source: USDA Natural Resources Conservation Service, 2010 National Resources Inventory, tables 2, 12.
Note: Usable open land is estimated as total rural land minus "other rural land." Other rural land is either covered by rural structures or is rocky, swampy, or barren therefore not usable without significant improvement.

The 2010 National Resources Inventory (NRI) of the NRCS (USDA and ISU, 2013) allows a fairly precise and updated estimate of the rate of loss of various types of land due to urbanization, because it reports the amount of each undeveloped land type *remaining* in each survey year (Table 1). The data on remaining rural acres are available for each of the lower 48 states for seven years between 1982 and 2010. The first row of Table 1 reports data for the entire United States. Because local conditions vary widely, the remaining rows report data on a set of representative states from different census regions throughout the United States.

The first column of Table 1 shows the percentage of undeveloped, nonfederal land in each state that was characterized as NRCS prime farmland in 2010. The second column shows the percentage decline in prime farmland in each state between 1982 and 2010. The third column shows the percentage decline in available rural acres of all types, including forested, that could be used to raise food or livestock if needed.

Northeast states have seen much of their farmland revert to forest over the last century; there is no reason why we could not reclaim some of this land for food production if necessary. Having said that, it must also be acknowledged that a significant portion of today's forests are on steep slopes or are regarded as necessary for wildlife preservation, carbon sequestration, or other environmental services. For this reason, Table 1's final column shows the percentage decline due to urbanization of all non-forested, open rural land that existed in 1982. Together, the three right-hand columns in Table 1 span a range of subjective definitions of open land that should be used, or considered a reserve, for agricultural production in the United States.

The first thing to notice in Table 1 is that prime farmland has been declining more rapidly than all rural by development, economic incentives cause "forest, pasture, range, and other rural land [to be] converted to cropland," thus reducing the net effect on food supply (Heimlich and Krupa, 1994). The existence of market forces means that straight-line forecasts are unlikely to come true; still, they can provide an intuitive sense of the urgency of farmland loss in different locations.

For the continental United States, a straight-line projection technique suggests that prime agricultural land would be completely eliminated in appears to have some holes in it. A quick look at maps published in the 2013 NRI report shows that Iowa is the continent's epicenter for "sheet and rill erosion" producing sediments that flow down the Mississippi River. This fact should remind us that prime U.S. farmland can disappear for reasons other than urbanization. In Iowa, continued availability of topsoil is the chief threat; in Florida, inundation from rising sea levels might be considered, alongside urbanization. In California, farms in the state's famed central valley could run out of

A Prime Farmland Risk Profile for the 48 Contiguous States

There are different ways to characterize the risk to farmland from urbanization across states, and therefore where to prioritize preservation efforts. For example, we might ask the question: Which states have a high percentage of farmland that is designated prime? Other things equal, these are places where a state-level preservation effort would have the greatest impact on prime farmland, viewed nationally. Figure 1 shows that these states cluster in those parts of the country with sufficient rainfall, drained by large river systems, and with land that is relatively flat.

But Figure 1 ignores the threat to this prime farmland that is generated by urban growth. Figure 2, therefore, shows housing growth over the same period for which farmland decline is measured in the 2013 NRCS report. This map shows the well-known sunbelt/west coast growth phenomenon of the last several decades. It is silent, however, on whether growth in a given state is eliminating prime farmland at a faster rate than other kinds of rural land.

Figure 3 addresses this third question—while ignoring the first two. It shows states that rank above the median on the ratio of prime farmland decline to decline of all rural land. These are states where prime farmland is disproportionately in the path of development, viewed independently of the speed of that development.

In the west, Figure 3 looks similar to Figure 2. Not only has the West been growing rapidly, it is also understandable that western cities were founded close to this region's very limited stocks of prime farmland.

Comparing the Northeast and Southeast regions in Figures 2 and 3, however, leads to the conclusion that states losing prime farmland more rapidly than other rural lands—generally in the Northeast—are not the states that have grown most rapidly, which are generally in the Southeast. States with a disproportionate quantity of prime farmland do not align neatly along north-south lines which can be seen in Figure 1. Having said that, it is clear that northeastern states with slower long-term growth rates but greater relative risk to prime farmland have been more actively preserving land than their southern counterparts (AFT, 2005).

Are there any states that rank high on all three farmland preservation risk factors? Yes, there are two: Texas and Alabama. Neither of these states made AFT's 2005 roster of states authorizing and using state funds for preservation (AFT, 2005). A likely explanation is the South's small-government political culture. Private foundations may be picking up some of the slack by purchasing conservation easements in these two states.

relatively few fruits and vegetables sold in America's supermarkets today are local, such high-value crops could potentially be grown on the fringe of any metropolitan area even as this fringe moves outward.

An important reason for this is that prime farmland is not strictly required to grow fruits and vegetables. In fact, as noted by a reviewer of this article, high-value fruit and vegetable crops often require soil characteristics that preclude a soil from the prime designation. Given the high water content of these commodities, access to water for irrigation is a more important spatial resource than a particular type of soil or access to adjacent urban markets. California's Central Valley, a global exporter of fruits and vegetables that is removed from the state's largest cities, is now putting this constraint to the test.

Will Urban Sprawl Continue in North America?

The U.S. Department of Housing and Urban Development (HUD) journal *Cityscape* recently commissioned a set of essays on the question of whether Americans would live more or less densely in the future (HUD, 2013). A key question raised by the authors was whether residential preferences in North America would change with a continued increase in incomes. One scenario assumes that consumers will demand homes closer to their jobs, with walkable neighborhoods and city amenities. A continuation of the historical trend toward more personal open space in back and side yards, however, is also logical. Affluent homebuyers could eventually split into high- and low-density groups, based on personal consumption preferences.

Other factors in this debate include the aging of the population, leading to higher density housing; lack of funding for highway construction, which will limit one important driver of past decentralization; and crosscutting preferences by modern industry for urban agglomeration on the one hand, and telecommuting or back-office development on the other. Interestingly, the possibility that high food and agricultural land prices might "push back" on the urban-rural boundary, leading to higher residential densities, is not mentioned in the symposium issue.

In the aggregate, the *Cityscape* forecasts predict a slowed-down continuation of sprawl in North America, with a lot of density variation and experimentation within metropolitan areas. Metropolitan areas will still be quite large and will, in some areas, bleed into each other. That being said, forecasts of urban densities and the overall urban footprint in the United States and other developed countries vary widely. Ironically, this is also true of forecasts of future cropland demand in North America under—and even without—considerations of climate change (Schmitz et al., 2014; Hertel, 2010). At some level, then, we simply do not know what our land use future will look like, other than the safe bet that urban land will constitute a small minority of the continent's land mass for many years to come.

Farmland Protection and Public Policy

Even if you are not an economist, the market paradigm remains an important starting point for thinking about farmland preservation policy. Some economists and planners are perfectly happy with the land use choices the market appears to be making today (Gordon and Richardson, 1997; 2006). When an acre of farmland is lost, these authors argue, it is because housing was the "best and highest use" for that parcel at that particular time. More specifically, the foregone opportunity of using prime farmland for agricultural production is already captured in today's price, so the development of such a parcel cannot possibly be a problem. Working on its own, the market gets the right answer.

This argument would be sound if land could move in a costless way back and forth between urban and rural uses in response to new market information. The common assumption that urban development is irreversible, however, leads to an "option value" argument that tends to support the preservationist point of view. If too much land were developed, advocates argue, we would lose the option to use it as a cushion against global famine. The opposite mistake—having insufficient land for development because too much is being cultivated—is both harder to imagine and easier to reverse. Sure, some consumer satisfaction is lost by constraining development today, but isn't food ultimately more essential to life than an extra thousand square feet of home or lawn?

A second economic rationale for farmland preservation begins with the premise that development is characterized by numerous market failures today, leading to the conclusion that our urban landscapes sprawl inefficiently. Brueckner (2000) provides a nice summary of these market failures, without concluding that they are severe enough to justify massive planning controls. One such failure, which might actually be the crucial one, is that there exists no private market in which citizens can purchase open space and amenity services from their farmer neighbors. Farmers therefore lack any incentive to provide these services by postponing development. Indeed, the 40-year-old public market, in which taxes are used to purchase development rights on farmland, can be viewed as a collective stand-in for this non-existent private market for local amenities. It is supplemented by a private, nonprofit market for open space. Taken together, there is no guarantee that these programs serve the multiple demands of residents as well as a formal market for ecosystem services, or even greater central planning, would.

Perhaps easier to deal with are those cases where misguided government policies, not failures of the free market, are to blame for the rapid pace at which we chew up our farmland. Why, for example, would anybody think that a zoning ordinance specifying a minimum residential lot size of five acres is a good thing? There is one efficiency rationale for this widespread restriction on housing choice that only economists talk much about (Hamilton, 1976; Fischel, 2001). But this rationale assumes a local property tax—something we could change if we wanted—and it is arguably outweighed by a long list of inefficiencies and inequities commonly associated with large-lot zoning and its landscape cognate, urban sprawl (White, 1975; Levine, 2005; Rudel et al., 2011).

It is noteworthy that farmland preservation—especially if it contributes to increased urban density and contiguous development—is a potential solution for a range of efficiency and equity problems that have nothing to do with future food security. If concerns about the future availability of food create the political will for a more efficient, more compact city, then these concerns may prove to be a useful fiction.

So what have preservation programs been doing since the 1980s to slow the loss of farmland near metropolitan areas? According to figures compiled by AFT, state agencies and nonprofits have preserved more than 1 million of the nation's agricultural acres nationwide, with the Northeastern states and California understandably near the top of the list (AFT, 2014a). This figure amounts to less than 1% of the total agricultural U.S. land base. While that may sound miniscule, these mostly state-driven programs typically target prime soils lying in the path of rapid development.

There is certainly no guarantee that these programs solve the sprawl problem. Housing can continue to be built at low densities and can 'leapfrog' over the protected parcels. The achievement of local food and amenity objectives demanded by voters, on the other hand, is likely. Fortunately, the people who are most concerned about such objectives are the ones paying for preservation, aided by federal tax write-offs and a few modestly-scaled programs of the USDA.

The federal government could, if it wanted, pump more money into this proven system. Aside from the general problem of fiscal austerity, this would require greater consensus among federal lawmakers on the food security aspects of the problem. Alternatively, it would require greater bipartisan commitment to urban planning objectives at the federal level, through an agency like HUD. Neither appears likely any time soon. Meanwhile, the recent consolidation of the Farm and Ranch Lands Protection Program into a broader Agricultural Conservation Easement Program has injected some uncertainty into the process of obtaining federal grants for the purchase of easements on working farms having little or no environmental significance.

If the age of sprawl is over, however, then farmland preservation activists can turn their attention to the neglected subject of managing our half-preserved, half-developed exurban mosaic for maximum efficiency in the production of food, fiber, and amenities. This is likely to be easier than taking the long view on land to minimize downside risks. That is something that the political establishment finds difficult under the best of circumstances.

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Farmland conversion to non-agricultural uses in the US and Canada: current impacts and concerns for the future

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Conversion of farmland to non-agricultural uses presents a challenge to future food production and ecosystem services in US and Canada. Expansions of housing, transportation, industry, retail sales, schools and other developments are driving land out of farming. In the US there is annual conversion of 500,000 ha away from food and fibre production systems. Coupled with 1% annual population increase, this will reduce today's 0.6 ha per person to 0.3 ha by 2050. Canada has more land and smaller population, but farmland losses are occurring in fertile areas near coasts and in level valleys where highest quality land is located. Current rates of increase in agricultural productivity will not compensate for this land loss. Compared to US, there are more specific tools and legislation at the provincial level in Canada that provide opportunities for controlling sprawl. Important in both countries is general lack of awareness and concern about loss of productive farmland, a situation that could be improved through education. Stimulating collective understanding of this growing problem and providing viable solutions could provide the basis for national policy strategies to promote and assure sustainable food systems for the future and enhance the capacity to maintain vital ecosystem services.

Keywords: ecosystem services; farmland conversion; food production; food security; food sovereignty; open space; self-sufficiency; urban sprawl

Introduction

Evaluation of current land use for food, feed, fibre and energy production in the US and Canada paints a bleak picture for farmland availability in the future. Such an analysis must consider projected increases in population and improvements in agricultural technologies, along with the rate of land being converted to non-farm uses. Although most people recognize the effects that growing scarcity of fossil fuels and water will have for agriculture, there is less awareness of other factors such as loss of prime agricultural land to other human pursuits. There is even less concern among the general population about essential ecosystem services that are provided by farmland and natural areas, such services as providing clean water, reducing soil erosion, mitigating impacts of severe weather, preserving biodiversity and maintaining open land for recreation.

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These are rarely recognized in the contemporary economy. In this review we explore the magnitude of farmland loss in the US and Canada, the reasons why this is occurring, the multiple consequences of conversion of land to non-farm uses and the potential alternatives in each country to counter this trend in order to ensure sustainable food systems.

In their seminal book *Under the Blade: The Conversion of Agricultural Landscapes*, Richard Olson and Tom Lyson (1999) brought together copious statistics from the US federal census (USDC 1996) with those of the American Farmland Trust (AFT 1997) and other sources to quantify the conversion of farmland to other uses and to evaluate the motivations behind these critical changes. The data available confirmed a long-term trend of land moving out of basic agricultural production. Further complicating the future of food production was their description of the loss of the best lands, those that are relatively level and have greatest potential for irrigation, and the lands located near cities. Disproportionate use of energy per capita in the US and Canada increases greenhouse gas emissions, and loss of farmland reduces our capacity to absorb them. Population growth further accelerates the loss of land and reduces the potential for food production per capita.

Multiple factors influence decisions to convert land to non-farm uses (Olson and Lyson 1999; Hansen and Francis 2007). To either promote or mitigate the obvious economic benefits of developing land for other intensive human activities, there are diverse local and state laws that may facilitate land conversion and some that protect land. Future-oriented national programmes reward protection of lands for specific uses, such as saving wetlands and buffer zones along streams and lakes to prevent or ameliorate the effects of pollution from agriculture. Changes in the demographic distribution of land ownership, a resource often viewed by farmers as an investment for retirement, have raised the age of principal farm owners and operators in the US Midwest to 58 years (ERS 2009). Most land is owned by older people, and about half of the land currently farmed is rented or leased from others (Carolan *et al.* 2004). Lack of appreciation in the general public of the ecosystem services provided by farmland and natural areas is another factor complicating political decisions to allow or prevent farmland loss (Daily 1997).

Two important papers have appeared recently in this journal. A spatial analysis of changes in land use in eastern Canada based on GIS data was used to provide a rational basis for policy development (Bucknell and Peterson 2006). In this paper, the authors described how on-farm income has declined in southern Ontario from 1991 to 2000, while in the same period income has increased in southern Quebec. The conclusion was that changes in rural populations and communities may or may not contribute to sustainable local economies, and that policy decisions should be specific to the uniqueness of each region. In the Greater Vancouver area there was also broad debate about the contributions and future of agricultural land preservation and economic potential (Condon *et al.* 2010). Condon and colleagues argued that food security (local supply) and food sovereignty (local control) were both key issues that were not considered by conventional industrial agriculture and agri-business. They further speculated that ‘Municipal Enabled Agriculture’ could serve as a central alternative that would inform the process of planning and design of strategies to increase resilience and sustainability to the food system and community.

There is no question about the short-term economic returns that accrue to some individuals who acquire land for activities other than agriculture. Factories, housing subdivisions, commercial malls, highways and other intensive uses add immediate value to converted land, yet the long-term consequences of losing agricultural production are not part of the accounting. There is a need for a balanced approach to controlling short-term windfalls realized by a few with the long-term needs of society for food and other products from agriculture.

In the face of these challenges, the two countries have designed a wide array of legal mechanisms to prevent the sprawl of human development across prime farmland. These are different in some ways between the US and Canada, and among states, provinces and local jurisdictions.

There are tools for protection found in both the public and private sectors that can be used by concerned citizens and organizations. In the following sections, we present the current situation in the US and in Canada, as well as the consequences of continuing to follow the current path of relatively unconstrained conversion of land. A number of options are described that can reduce or reverse land loss trends and preserve our vital agricultural land and soil resources for future generations.

Through publicizing these changes, scientists and educators can join other concerned citizens to become more aware of current changes, understand their long-term implications and subsequently play a role in preserving land for agriculture. We can learn from environmental organizations and public institutions in Europe where there is a higher level of consciousness about the long-term need to protect natural areas and farmland. This review has been prepared in collaboration with the authors of a parallel study on land conversion to non-farming uses in Australia (Millar and Roots 2012).

Farmland conversion in US

Driving across the US Midwest, one sees few obvious or compelling indications that there is a crisis in loss of farmland. On the surface, there appears to be plenty of 'open space' for agriculture. When moving from east to west one can observe substantial irrigation in the lower rainfall areas and the apparent potential for further expansion to continue the trend of the last few decades. There are over 12 million ha set aside in the US in a Conservation Reserve Program (CRP) that can be brought into primary production when needed (Cain and Lovejoy 2004). However, what is visible reveals neither the rate or consequences of farmland loss nor the critical locations of these losses, which are in areas with the most fertile soils. Also unsustainable are the impacts of subtle declines in today's conventional system production potential due to increases of input requirements, reduced soil quality due to intense exploitation, serious genetic plateaus in the principal cereal crops and constraints on key resources such as fossil fuels, phosphate and shrinking water supplies that will impact our ability to compensate for land loss in the future.

Modern agriculture in North America, as in all continents, was first practiced on the most fertile and accessible lands. Farming was concentrated along the coasts, in flood plains of river valleys and in broad and productive grasslands and cleared forest lands. These areas were also where people first settled and where they continued to build as the human population expanded. One specific example is the fertile San Joaquin Valley of California where the first author (C. Francis) was raised. First there was a north–south rail line built along the least costly route in the centre of the valley, followed by a parallel highway that was improved from a dirt track to a two-lane paved road and eventually to today's six-lane freeway. Cities from Bakersfield to Sacramento grew out from this transportation corridor, spreading over some of the best farmland in the world. As an example of the conventional evaluation of such regions, a contemporary look at the demographics and economy of this area confirms its current productivity and value to the state's economy (Umbach 2002), but totally fails to take into account the conversion of land away from farming and the long-term impact of aggregated changes in this most populous state of the US. A specific example from Fresno County is valuable to illustrate the change. While 6,000ha were lost from farming from 1990 to 2000, it is projected that an additional 50,000ha will be converted to non-farm use by 2040, and over half of this will be high-quality farmland (AFT 2011b).

Similar patterns of agricultural land use developed along the rivers of the vast Mississippi system in the central US that drains 41% of the total continental area (minus Alaska), and across fertile coastal plains. An extensive Interstate Highway network was initially planned for military and logistical reasons, yet an emergent property of its construction was a strong impact on economic and social planning as towns and businesses along the favoured routes flourished and acted as a magnet for development and movement of people from elsewhere. Prime farmland was lost to highways, industry and urban infrastructure. Land seemed to be abundant, and there appeared to be little reason to conserve productive areas from other development. Today, not only is land being converted to non-farm uses, but the most productive lands continue to be the ones most vulnerable to further loss.

There are currently about 180 million ha of high-quality, productive farmland in the US (NASS 2008). With a population of just over 300 million people, this land resource provides 0.6ha of farmland per person. With compounded increase in the US population at 1% per year for the next 40 years and constant farmland loss of 500,000ha per year, there will be 0.3ha of farmland per person by the year 2050. The population increase and especially the land conversion rate are conservative estimates. A critical question is whether productivity and total production can be sustained to meet the demands of both domestic and export markets. Sustaining current production with constraints to energy and water inputs is discussed later, along with the potential positive contributions of research to increase productivity that may partially compensate for land moving out of agricultural production.

Quantitative estimates of conversion of quality farmland by Peterson *et al.* (1997) show that over half the land in the US currently under urban use has moderate to high quality for farming. However, in some states this proportion is much higher, for example 83% in Pennsylvania and 96% in Illinois. As reported by Olson and Lyson (1999), in addition to conversion of the best farmland, there is evidence in metropolitan areas that increases in developed land are far greater than population increases. One example is the five-county area around Philadelphia where a 3.5% increase in population (1970–1990) was accompanied by a 34% increase in change of land use to development (Smith 1999). For Chicago, in the same two-decade time period, there was a 4% increase in population but a 46% increase in urbanized land (1000 Friends 1997). Finally, Milwaukee has experienced a 47% increase in population from 1950 to 1985, while land converted to urban uses has increased by 227% (Erickson 2007). Evidently, we are using land less efficiently for urban purposes, and the amount of 'built land' per person is increasing in each of these metropolitan areas. Such land loss near cities is crucial, because in the US some 70% of all vegetables and ornamental plants are produced in counties contiguous with major population centres (Rabinovitch and Schmetzer 1997). The American Farmland Trust reports from the 2007 Census of Agriculture that 91% of fruits, tree nuts and berries; 78% of vegetables and melons; 67% of dairy; and 54% of poultry and eggs are produced in 'urban influenced counties' (AFT 2011a), and these are the same areas experiencing a disproportionate loss of land relative to population increase as detailed above. We conclude that there should be more concern about the absolute conversion of farmland to other uses in the US, and especially about the loss of quality land near cities. An apparent inability to deal with this crisis through existing programmes leads to the recommendation that a national strategy for farmland preservation should be seriously considered.

Farmland loss in Canada

While the total land area of Canada is 3% greater than the US, the much smaller national population of 33 million gives a population density of 3.5 persons per km^2 (Statistics Canada 2009), as compared to 31 persons in the US. Similar to the experience of travelling across the US Midwest, it would be difficult to convince a person traversing the prairie provinces of Manitoba, Saskatchewan and Alberta that land conversion away from agriculture could be a challenge to food production. However, unlike the US, only 7% of the total land base in Canada is suitable for agriculture, and only 5% of the land base is considered to be 'dependable' agricultural land which has a soil capability that presents no severe limitations to crop production (McCuaig and Manning 1982; Hofmann 2001). Thus the available fertile land per person is similar to that in the US.

In Canada, many successful and growing cities started as small agricultural trading centres. Part of their original comparative advantage was proximity to productive and fertile agricultural land, as well as to markets. Now, the continuing expansion of cities is consuming high-quality agricultural land which causes a number of direct and indirect consequences, including loss of production, increases in the costs of inputs on less fertile lands, greater transportation costs to bring products to market and loss of ecosystem services. In addition to the expansion of urban buildings and parking, the new highways, utility corridors and other infrastructure also consume high-quality agricultural land. Despite Canada's immense size, dependable agricultural land is a scarce resource. Limitations such as climate, topography and soil quality reduce the amount of land that can be used for consistently successful agriculture (Hofmann *et al.* 2005).

Dependable agricultural land is scarcer in some parts of Canada compared to others. Although Quebec is the largest province, only 5% of all dependable agricultural land is found in this province (Hofmann *et al.* 2005). Three-quarters of Canada's dependable agricultural land is concentrated in Saskatchewan, Alberta and Ontario (Agriculture and Agrifood Canada 2008). In Canada as a whole, between 1951 and 2001 the availability of dependable agricultural land declined by 4% due to urbanization and conversion to other non-agricultural uses, while the demand for cultivated land increased by 20% (Hofmann *et al.* 2005). Due to the limited availability of good farmland, its loss may have implications for long-term agricultural and food sustainability.

Since population density is not consistent across the country, there is an impact on the functionality of the limited agricultural land base. Some 60% of Canadians reside in a narrow southern band along the Windsor–Quebec City corridor, and across the country there is a predominant population settlement and north–south trade pattern bridging the Canada/US border. As this is also where the vast majority of the dependable agricultural land is found, the effects of population growth and urbanization on the conversion of agricultural land tend to be highly detrimental to the nation's agricultural productivity (Hofmann 2001). In large urban centres in the southern part of the country, population density averages 245 persons per square km (McCuaig and Manning 1982). Within some of the urban centres the population density can reach 5,000 persons per square km. The centres with the highest population concentration are the areas that had the best conditions for settlement in the past. These conditions included a good climate, proximity to a major waterway and abundant fertile land, which made these areas the economic activity focus of the country (McCuaig and Manning 1982). For the same reasons, these centres continue to attract people. Canada has a fairly flat human population fertility rate, so immigration, rather than natural growth, is the most significant contributor to population growth in the country. For economic and cultural reasons, most immigrants tend to settle in large metropolitan areas. Therefore most population growth is occurring in urbanized areas. For instance, more than 86% of the population growth between 2001 and 2006 occurred within the country's 33 largest metropolitan areas (Gartner 2008). The combination of population growth in these areas, of affordability of private automobile travel, and of increases in the average amount of land used per dwelling has resulted in urban sprawl, which is negatively affecting the agricultural land on which these urban centres originally depended for a large part of their economic success.

Between 1986 and 2006, Canada as a whole experienced a net loss of more than 239,000ha of farmland (Statistics Canada 2008). While this seems inconsequential in comparison to the US, where over 500,000ha of productive farmland are being converted away from agriculture each year, these national statistics in Canada do not capture the whole magnitude of the problem. When the data are viewed on a province-by-province basis, the picture becomes clearer. For instance, in Ontario during the same two decades, more than 20,000ha or 4.6% of productive agricultural lands were converted. This number is higher than the national average because British

Columbia and Alberta showed net increases in the amount of agricultural land over the same period. However, the picture is not positive for western provinces either. The net increase is partially due to changes in the way leases of Crown land (government owned) were tabulated as agricultural land (Statistics Canada 2008), but it is also due to more marginal land being brought into production.

The quality of land being lost as well as the total area must be taken into consideration when evaluating the magnitude of the problem. In the 25-year period between 1971 and 1996, growing cities and towns in Canada consumed more than 12,000km^2 of land, and roughly half of this total was dependable agricultural land (Hofmann 2001). As of 2001, 11% of the Class 1 farmland in Ontario had been permanently converted from agriculture to urban uses (Hofmann *et al.* 2005). Even in provinces that are showing a net increase in agricultural land, there have been large losses of quality agricultural land. For instance, in British Columbia, despite the existence of legislation protecting agricultural land, more than 34,000ha of agricultural land were excluded from the province's Agricultural Land Reserve (ALR) between 1974 and 2009 in the highly productive areas of the Okanagan Valley, the Lower Mainland and Southern Vancouver Island. During the same period, more than 68,000ha were included in the ALR in the northern regions of Peace River, Kitimat Stikine, Fraser Fort George and Bulkley Nechako (Agricultural Lands Report 2009). Although this has resulted in a net increase in the amount of agricultural land in the province, the land in the northern regions is generally not dependable agricultural land, and is most suitable for extensive grazing and possibly grain or hay production. The land excluded in the south is well suited to growing intensive fruit and vegetable crops. The magnitude of the problem cannot only be shown through absolute numbers of hectares of land gained or lost. Thus, the loss of quality land for agriculture is a major challenge for long-term food security and sustainability in Canada.

Consequences of farmland conversion

Conversion of farmland to other uses in both countries has a number of direct and indirect consequences, including loss of food production, increases in the cost of inputs needed on lower quality land that is used to replace higher quality land, greater transportation costs of products to more distant markets and loss of ecosystem services. Reduced production must be replaced by increasing productivity on remaining land or by farming new lands.

In the US, farmers have realized consistent increases in productivity. For example there have been average annual yield increases in maize (100kg/ha/year) and in soybean (20kg/ha/year) over the past five decades. About half of this increase in the early decades was due to genetic improvement (Egli 2008). Another indicator of future potential is the narrowing gap between the highest experimental yields and the yield contest winner levels for maize production. This could represent an opportunity to improve farm productivity by closing the gap (Duvick and Cassman 1999). However, these authors point out that irrigated maize yields in farmer contests have not increased over the past three decades, indicating that we are near a plateau in genetic yield potentials of this major crop, and the same authors have observed similar statistics for rice and wheat, the other two principal cereal crops worldwide. Moreover, research costs have gone up far more than the increases in maize yields, indicating a continuing reduction in the benefit/cost ratio to crops research. When more marginal, less fertile lands are brought into production there is often an increased need for purchased inputs, especially fertilizer, and the new areas may be farther away from markets and other established infrastructure. It appears that there is a limit to what technology can provide.

Impacts of the recent global rise in petroleum prices and consequent increases in fertilizer costs, coupled with increased grain commodity and land prices, have complicated the evaluation of long-term changes. However, these changes can be examined in the context of research and adoption of new technologies and how they impact production and productivity. The spikes in grain prices in 2008 and again in 2011 were accompanied by corresponding price hikes for inputs, especially in the cost of nitrogen fertilizer, but generally when grain prices go down along with less expensive oil the costs of inputs do not decline nearly as much or as fast (Ali and Vocke 2009). In the US Midwest, the rapid climb in commodity prices also pushed land sale and land rental prices to much higher levels, and these also appear to not decline with the price of grains (Ali and Vocke 2009). We observe in the US Midwest that the increase in farmland value has not offset the pressures of urbanization near population centres and prices paid by developers, since even the rise in grain prices and potential for more farm income scarcely increase the value of this same land enough to compete with urban development. Increase in farmland value follows a similar pattern to that in Australia (Millar and Roots 2012).

In 2001 in Canada, there were about 14,300km^2 of urban infrastructure occupying dependable agricultural land, more than double the 1971 level of 6,900km^2 (1km^2 = 100ha) (Bollman 2005). Approximately 46% of urban activities in Canada were situated on dependable agricultural land in 2001, and over 11% of Ontario's best agricultural land (Class 1) was being used for urban purposes. Urbanization of agricultural land affects conventional crops and specialty crops that have a limited range of adaptation in Canada. Niche crops can make important contributions to local economies, such as the fruit belts in Ontario's Niagara region and in British Columbia's Okanagan Valley. In such cases, the loss of each km^2 can be significant. Farmland conversion hurts local economies because of agriculture's economic multiplier effects (Armstrong and Taylor 2000), although other uses of this same land can contribute substantially to local development in the short term. Each dollar earned by crop agriculture or other local businesses stimulates additional indirect economic activity by over three times.

Cities also promote changes in the use of land beyond their boundaries. For instance, golf courses, gravel pits and recreational areas are often located on agricultural land adjacent to urban jurisdictions. Thus, the effects of urban areas extend beyond their physical boundaries. The negative consequences of this consumptive form of urban growth are significant not only to the viability of the agri-food industry and the ecological integrity of the natural environment, but also to the long-term quality of life of residents. The positive externalities associated with agricultural land are public goods, having value separate from the economic benefit of producing marketable commodities (Daily 1997). Nearby agricultural land improves a community's quality of life through its open space and other aesthetic properties, biodiversity and natural habitat, and provides a contrast to urban congestion. Access to locally grown products is appealing to many consumers.

Ecosystem services from farmland, fields and forests are described by Daily (1997). In both the US and Canada the importance of such ecosystem services is underappreciated and rarely recognized economically. Natural wetlands absorb and contain water, reducing peak flows, and also play a role in cleaning water. The positive effects of woodlands include reducing wind speed, intercepting particulates that carry odours, capturing carbon and producing oxygen. Lands with crops, forests, grasslands and other cover have the ability to break the force of rain and wind, reduce soil loss and store water for subsequent crops. These uses are not well known to the general public. Much of the capacity for land to serve society is lost when these areas are paved and developed. A major challenge is that most ecosystem services are not rewarded in the formal marketplace, and most are taken for granted or not appreciated at all by the general public.

Policy strategies in the US and Canada

Saving farmland is an investment in community infrastructure and economic development for the long term, although there are trade-offs with the immediate benefits of other types of land use. The concept of 'implicit economic multipliers' in assessing long-term benefits of keeping land in farming and other natural resource use may be illustrated with an example from Brevard County, Florida (Clouser *et al.* 2010). While recognizing that retail and wholesale trade, city growth and other alternative land uses must be evaluated to assess their potential for local economic development, a convincing case is made for considering agriculture as important in long-term economic planning for development and elaboration of rational policy strategies. Planning for agriculture and protecting farmland provide flexibility for future growth and development, offering a hedge against fragmented suburban growth while supporting a diversified economic base. Keeping land available for agriculture while improving farm management practices offers the greatest potential to produce or regain environmental and social benefits while enhancing food security and food sovereignty (Wittman *et al.* 2010). A historical comparison of approaches and their impacts in US and Canada has been published (Furuseth and Pierce 1982), and our review updates the previous comparison.

Strategies in the US

Among the available strategies in the US are public and private initiatives at the national level, such as the CRP and American Farmland Trust. In addition there are numerous state and local programmes that include agricultural land trusts, agricultural and other special purpose zoning laws, right-to-farm laws, transfers of development rights, smart building incentives and cluster zoning for concentrating human dwellings on less land that is encouraged by tax credits for urban renovation and increased housing density (Olson and Lyson 1999).

The largest and most visible public sector programme is the federal Farm Bill that is negotiated and enacted every 5 years in the US (AFT 2011c). As an example of recent legislation, the agricultural part of the 2002 Farm Bill focused on the Conservation Security Program to preserve soil and on clean air and water, wildlife habitat and farmland protection. The 2008 Farm Bill was intended to establish a financial safety net for farmers while also fostering soil conservation, rural economic development and more healthy and local foods. In the 2012 Farm Bill negotiations there is discussion of dropping direct commodity payments while instituting a paid income assurance programme, enforcing better policies to protect farmland and encouraging stronger environmental stewardship. The bills are always a focus of strong debate between powerful commodity groups that support federal payments based on production and environmental organizations that promote rewards for conservation.

Although these federal programmes provide some incentives to farmers, most tools and mechanisms are available at the local level, and it is up to state and county jurisdictions and their planning offices to apply them to local situations. In a recent publication, we classified policy tools to protect farmland into three general areas: those that promote enhanced agricultural competitiveness, those that enhance planning efforts and those that provide conservation tools (Hansen and Francis 2007). In most states there are multiple programmes available to help preserve economic potentials of farms: differential valuation assessments, right-to-farm laws and agricultural zoning. There are also federal support programmes of various types that are available in all states, including conservation laws for farming practices, filter strips and shelter belts, and wetlands. A number of these are summarized in 'The Farmland Protection Toolbox' published by the American Farmland Trust (AFT 2008). Among the more frequently used tools are:

1. *Differential land valuation*: Greenbelts around cities, designed to allow for a differential valuation of land to be used for agriculture, allow local governments to assess land for its agricultural value rather than for the present fair market value for other uses. This may be enough incentive for farmers to stay economically viable because of the lower

property taxes. The lower taxes are justified because farmland requires much less expense per acre for vital public services from the community, such as city infrastructure for water and sewer and services such as police and fire protection. The American Farmland Trust (AFT 1997) found in over 100 US communities that productive farmland produced more public revenue than the cost of services received from the community. Most residential land, especially houses in suburbs, provided less revenue than the cost of services because they are often connected directly to sewer and water, and their distance from the city centre causes the cost of infrastructure services to rise. One method is to establish conservation areas or green belts in ways similar to those used in Europe to curtail urban sprawl. In fact, there is a city in Maryland named 'Greenbelt' that was designed in the 1930s as part of President Roosevelt's New Deal (Greenbelt Community Website 2006). Their website describes unique features of this community, as well as additional reference materials.

2. *Right-to-farm laws*: Farmers and ranchers are protected in all states by right-to-farm laws that can legally protect farmers from conflicts with urban neighbours or people on rural acreages who move into an agricultural area after the farms were established. These discourage but do not prevent neighbours from filing against farm land owners for suspected nuisance activities, such as odours and flies from livestock or poultry, noise and dust from farming operations, or drift of pesticides applied to field crops. For example, in Nebraska the Department of Environmental Quality oversees the Right-to-Farm Act that provides some protection to farmers, although this is not absolute. Studies of counties in California revealed that right-to-farm laws and other legal ordinances were not enough to help people come to accommodation at the urban–rural boundary. There is a need for good design, rational zoning to separate activities to the extent possible, and education of people on both sides of the chasm to be more sensitive towards the others' needs. A decade ago, the Iowa Supreme Court ruled that their right-to-farm law gave farmers an unfair advantage and that they could no longer continue as a nuisance to neighbours. This ruling may presage the loss of similar laws in other states, to the detriment of farmers and their right to farm.
3. *Agricultural zoning*: In order to protect farming enterprises near cities, there are national programmes to promote rational zoning for farmland protection, often implemented as local zoning rules that designate specific areas in which farming is the principal land use. Agricultural protection zoning is used to identify areas with farming as the principal land use, and to protect those areas from other land uses (AFT 2008). They generally designate the minimum land allowed for each dwelling, and the size varies from 20 acres (8ha) in the eastern US to 640 acres (250ha) in the more arid West. Sixteen states have Agricultural District Programs that prevent use of eminent domain by state agencies to convert farmland to other uses (AFT 2008). Cluster zoning is useful to help concentrate new houses in small areas while keeping much of the land in grassland, forest or farming, but this approach may not allow large enough tracts for effective use of today's large farming equipment. The method is more useful in promoting small scale and organic farming near housing areas or in preserving natural habitat (AFT 2008).

Minimum lot size for building may or may not be useful. In Lancaster County, Nebraska, a 20-acre (8ha) minimum lot size may serve to deter some people from building in rural areas. However, if a large lot adjacent to the city were to cost perhaps $100,000 for 2 acres (1ha), someone intent on finding a rural refuge could move out beyond the reach of development and easily purchase 20 acres (8ha) for $5,000 per acre with the same total investment in land, and thus defeat the purpose of agricultural zoning. In addition, the process is subject to the power of elected county councils, and these are often influenced by political, personal or financial pressures. Such an elected council may liberalize the rules in favour of development, rezoning areas and reducing minimum lot size for building. These moves could encourage farmland changes to subdivisions and encourage 'leapfrog development' where areas non-contiguous to the city are developed for housing.

Comprehensive planning helps local jurisdictions to use innovation in the design of long-term goals and patterns for growth (AFT 2008). The process leads to master plans that are updated periodically in response to changing conditions and new knowledge. Often they seek a balance between providing affordable housing and conserving natural resources, open space and ecosystem services. For example, in Lancaster County and the city of Lincoln, Nebraska, a joint city–county Planning Department and an advisory Lincoln–Lancaster Planning Commission were developed to help rationalize these problems and present plans to both the City Council and the County Board of Supervisors (www.lincoln.ne.gov/city/plan/). Statewide legislation provides the tools for counties to take charge of planning and zoning, a capacity that has been used recently to prohibit confined livestock production operations, mainly concentrated cattle and hog feeding enterprises, from locating on sites close to cities and rural communities. Such planning efforts can enhance orderly development, and zoning is a key tool in the public sector to promote such efforts to slow if not stop the conversion of nearby farmland to residential building areas. The development of comprehensive plans for growth has been a key feature of this community since the 1950s, and the result so far has been a relatively compact form of development. Smart Growth America (www.smartgrowthamerica.org/) tracks the degree of sprawl in metro areas, according to residential density, neighbourhood multi-use mixtures of land use, accessibility of major streets and strength of jobs and services in downtown and other activity centres. According to their study in 2002, Omaha, Nebraska ranked as the sixth least-sprawling city among 83 major areas that were evaluated. Thus Nebraska appears to have the proper legislation in place and local elected bodies that use the available tools to slow conversion of farmland to other uses.

4. *Conservation laws*: Agricultural conservation easements are another tool available to keep land in farming (AFT 2008 2010a). These are voluntary agreements between farmers and a qualified public or private entity, either a land trust organization such as the Audubon Society or a governmental body such as the local Natural Resource District. The farmer or other rural land owner keeps the right for farming, ranching or other purpose to maintain this open space, including holding the title to their property, and can sell, donate or otherwise transfer the development rights to one of these entities. The transaction becomes a legal part of their deed to the property, and the obligations move if the property is sold to new owners. There are often tax benefits for such a transaction. According to Hansen and Francis (2007), these conservation easements are 'interests in real property imposing limitations on the use of the property, including:
   - retaining or protecting the property in its natural, scenic, or open condition;
   - assuring the property's availability for agricultural, horticultural, forest, recreational, wildlife habitat, or open space use;
   - protecting air quality, water quality, or other natural resources; and
   - meeting other conservation purposes which may qualify as charitable contributions'.

   The purchase price must be acceptable to the property owners, or the rights on the property may be donated to the organization that will hold the development rights and the owners can realize a larger tax incentive as deductions from taxable income.

   There are numerous federal farm conservation programmes that are available through the USDA. These include the CRP, the Farm and Ranch Lands Preservation Programs (FRPP), the Grasslands Reserve Program, the Conservation Security

Program and the Wildlife Habitat Incentives Program (AFT 2010a 2010b). Each of these has specific rules for enrolment, and each has a limit to the amount of land that can qualify for federal support. For example, over 12 million ha are currently enrolled in the CRP program in the US, and over 100,000ha in the FRPP.

5. *Additional tools for farmland preservation*: There are other methods used in various states of the US, according to their own state laws and statutes governing local activities. Agricultural districts protect against special taxation assessments and nuisance lawsuits. Urban growth boundaries are widely used in Europe, and provide one method to slow land conversion in some communities in the US. Other tools include transfer of development rights, purchase of agricultural conservation easements, various types of tax relief or tax credits, cluster zoning to create higher density living units, and mitigation ordinances that require developers to permanently protect an equivalent area of farmland for every acre put into development (Hansen and Francis 2007).

   A recent example from Wisconsin is the 'Working Lands Program' that was part of the 2009–2011 state budget and that combines several approaches. Its three components are: updates of the state's current Farmland Preservation Program, enhanced ability of farmers and local governments to establish voluntary agricultural enterprise areas and a new state programme to help in the purchase of agricultural conservation easements (Wisconsin Department of Agriculture 2009). This is indicative of statewide programmes that are being implemented to help save farmland, taking advantage of both national and local programmes.

Strategies in Canada

Canada recognizes a need for farmland protection programmes which prioritize the continuation of agriculture as well as the coordination of agricultural land use policies with other land use decisions. British Columbia has provided a model in Canada with the Agricultural Land Commission Act, a policy approach that includes mechanisms aimed at growth management and preservation of agricultural land through an integrated policy approach. The strategy is founded on a long history of regional planning (Smith and Haid 2004). Legislation has also been enacted in Quebec, in the Act to Preserve Agricultural Land and in Newfoundland, with the Development Areas [Lands] Act. These three programmes depend on exclusive agricultural zoning to preempt the urbanization of agricultural land, a strategy that recognizes agriculture and related land uses as valued activities rather than temporary uses. Prince Edward Island has a Planning Act that acknowledges the need to protect agricultural land, yet all these programmes have only been marginally successful in slowing urban sprawl (Brouwers 2009).

The province of British Columbia has responded to intense development pressures from growing human population with multiple strategies to protect farmland. These tools are also used across Canada in other provinces, and provide an example of methods that could be useful as a model for planning in Canada and the US (Ministry of Agriculture 2011).

1. *Agricultural Land Commission (ALC) Act*: The Provincial ALR was created in 1972 in BC to establish *de facto* Urban Growth Boundaries (Ministry of Agriculture 2011). This legislative framework provides for preservation of scarce farmland. The ALC Act includes objectives, powers, application processes and guidelines for use of the Reserve, as well as defining relationships with local governments. Goals are to preserve agricultural lands, encourage farmers to cooperate with other land users and encourage local governments and First Nations to promote farming and other uses of agricultural land in their planning and policies (Provincial Agricultural Land Commission 2011).

2. *Farm Practices Protection Act (FPPA)*: Similar to other provinces, the BC right-to-farm act protects farmers from most nuisance claims if they can show that they are following practices defined as 'normal' within the FPPA. Local governments can legally influence what happens to agricultural land, and any variance must be authorized by the local government. Under the ALC Act, local governments may be delegated the powers to decide on requests for non-farm use (Ministry of Agriculture 2011).
3. *Regional growth strategies* (RGSs): Provinces are responsible for designing RGSs, including plans to maintain the integrity of productive lands. In exercising this responsibility, they may create inventories of suitable land and resources for future urban expansion as well as establish priorities for water use and conservation. The RGS may set urban containment boundaries. The purpose is to promote human settlement that is '. . . socially, economically and environmentally healthy and that makes efficient use of public facilities and services, land and other resources' (Smith and Haid 2004).
4. *Official community plans (OCPs)*: OCPs are local tools that must include geographic site designations and policy statements on agricultural land uses as well as those for land that could be environmentally sensitive if developed for other uses. An OCP must contain details of the amount and type of present and proposed agricultural land and its uses, while they may address additional issues such as the maintenance and enhancement of farming. Since the RGS in a given location has no direct influence on land use development rights, it will have an impact only by setting parameters around what OCPs and other rules can implement. Bylaws at the local level translate the policy in RGS and OCP into rules. Clear policies and precise language are essential in both an RGS and an OCP, so that these can be implemented through clear bylaws. They are similar to the comprehensive plans described above for the US.
5. *Zoning bylaws*: These rules classify land into zones that designate different allowed uses, and provide guidelines on building density, designate sites and sizes of buildings, and govern the use of signs. Several zoning elements that relate directly to agriculture include: larger minimum lot sizes; contiguous areas of farm land on individual lots and over larger areas; commercial land to accommodate agricultural service industries; regulation of non-farm uses; edge planning; rainwater management; direct farm marketing; and agri-tourism accommodation. Zoning bylaws can affect agriculture through regulations on such issues as composting, farm worker accommodations and where agricultural products may be processed (Ontario Ministry of Agriculture 2011).
6. *Farming bylaws*: Local governments can develop farming bylaws, which then must be approved by the Minister of Agriculture. Such local regulations deal with areas not within the scope of zoning bylaws, including farm practices, environmentally sound activities, designs of buffers and waste storage, and the size of farm buildings. It is logical that such rules are developed and administered at the local level, because of the importance of specific conditions that may be unique to the cropping and animal enterprises and the systems in each location (Ontario Ministry of Agriculture 2011).
7. *Agriculture area plans (AAPs)*: Local governments may also develop AAPs that develop specific recommendations to encourage and enhance agriculture. Agriculture Advisory Committees may be established locally to formulate AAPs. These plans can prepare reports on the status of agriculture and the land base, enumerate the opportunities and challenges facing agriculture, establish land use designations and policies and take into account the interactions between agriculture and nearby natural areas. Plans may include resource management, alternative economic development strategies, potential implementation plans for the AAP including staff and budgets, and recommended zoning amendments. An example is the farming plan for Ontario (Ontario Ministry of Agriculture 2011).

8. *Farm Tax Assessment Act*: This Act in BC can establish local regulations and guidelines for assessing the value of farmland that will then determine property taxes. These regulations can also provide methods to determine how changes in the designation of farm classes can lower farm property taxes (BC Assessment 2011).
9. *Community farm co-operatives*: Community cooperatives provide an innovative model to protect agricultural land. The community may protect a farm by purchasing a part of the property, and thus becomes a shareholder in what becomes *their* community farm. The farm may be operated by the farmer, but the land title is held in perpetuity by a society or land trust, with oversight of an elected board, with some details of farm operations and management directed by board members. Examples include the Keating Community Farm Cooperative on Vancouver Island and Horse Lake Community Farm Co-operative, both operating on land that is owned by The Land Conservancy (www.conservancy.bc.ca).
10. *Other methods*: These are additional methods currently used across Canada and especially in BC such as the Land Titles Act which allows local governments to register a covenant on the title to land to protect the nature of farmland, for example with no-subdivision clauses. Agricultural land can also be protected through outright acquisition. Land Trusts such as The Land Conservancy have purchased both farmland and ranch land, that is, 1,000-acre Talking Mountain Ranch which TLC leases to a ranching family. ALR on Crown land may be leased for longer terms, which are especially useful for ranch grazing lands. Owners of farmland have the option of donating a life estate to a land trust, retaining the right to remain on their property for the remainder of their life. If they move from the property or pass away, the property transfers to the land trust. A life estate may contain tax benefits depending on the value of the property and the length of time the owner remains on the property. It is possible to make a bequest of land to a land trust in a will.

    Permissive tax exemptions are available for riparian areas, leased municipal land for farming, development policy allowing agriculture to support the community, amenity charges, purchasing policy for re-sale items, homeplate restrictions and alternative farm model zoning. Each can be used under appropriate circumstances, thus providing a wide suite of opportunities for preserving land. If communities have the will, there are many ways of securing farmland and ensuring that new farmers are able to start businesses without paying very high land prices. These same provisions enable farmers to make a fair wage, encourage them to be good environmental stewards and stimulate food production for local consumption.

    One of the most spectacular projects in Canada is the greenbelt system in Ontario, where Toronto has a world-class recent initiative that now includes over 200km^2 (20,350ha) in what has been called the 'golden crescent' around the city (Friends of the Greenbelt Foundation 2011). This is part of a larger project called the Ottawa Greenbelt that includes over 728,000 ha (Ottawa Start 2011) and promises to provide an excellent model for the US and Canada. From this discussion of available programmes, it appears that Canada has a more robust set of options for preserving farmland at various levels of governance.

Awareness leading to action

How do we better understand and then communicate the realities and trade-offs of land conversion as well as the opportunities and alternatives available to decision makers and to the public? The first step towards viable solutions to reallocation of farmland to other uses is education and increased *awareness* of the challenges that exist for the long term. People are concerned about the price of food, so economic information about potential changes due to change of land use could be convincing. People raised in the US and Canada during an era of surplus food and federal land set-aside programmes may be difficult to convince about the critical importance of land conversion. However, available data on population growth and land loss can quickly bring the reality to those concerned people willing to do the calculations. Growing awareness of scarcity of fossil fuels and water and the recent focus on climate change and variability should help generate a concern that would have been nearly impossible a decade ago.

Given the awareness about land loss, what are people's *attitudes* towards finding a solution? With a small fraction of disposable income spent on food, and a greater concern for lower prices than for where and how food is grown, it is unlikely that education alone about the options for local food and food sovereignty will be convincing. However, general knowledge about agriculture's central role in the economies of many states in the US can be useful, including how the contributions from food exports have rendered those states more resilient during the recent economic downturn. People globally will continue to demand more energy and other resources, as incomes rise, and a country with fertile soils and food production potential will have a strong and enduring advantage in a resource-scarce future.

Most important after raising awareness and challenging people's attitudes is a focus on what specific *actions* can be taken to slow or reverse the land conversion trend. Since individual economic motivation appears to drive most decisions in these two countries, it will be useful to provide education about the financial benefits of limiting sprawl and development across the rural landscape. In addition to the food price argument, informing people about the increased property values near parks and open spaces could be useful in generating pressure to maintain those areas in an agricultural or natural state. Informed non-land owners and non-profit environmental groups can contribute to public awareness campaigns about the impacts of sprawl.

Conclusions

Through this paper, we have quantified the loss of farmland to other human pursuits in the US and Canada. The estimates and projections may be conservative, as conversion of some of the most productive lands near cities appears to be more serious than statistics demonstrate. Evidence was presented from three major cities (Philadelphia, Chicago and Milwaukee) that land is being used with increasingly lower efficiency under current development strategies and urban land use is increasing at a much higher rate than population. Gross statistics also obscure the nature of land loss, with some of the most fertile land for agriculture near cities, and this resource is the most susceptible to change in use from agriculture to other activities. We suggest that the first step is to create an awareness of the challenge, then provide compelling evidence to convince people and legislative bodies that their attitude towards this change of land use is critical to the future. These are the first steps towards action to meaningfully change the present trend.

There is little doubt that development will continue to 'use up' some of the best farmland in the US and Canada. Rather than wait for a crisis to drive our countries towards stricter laws about land use, it is important to seek more palatable options now by raising awareness and convincing people to take action to prevent excessive sprawl. Most of these decisions are best made at the local level, since the potentials and challenges of how land can best be used and conserved are unique to a place. Once land is paved, it takes extraordinary resources and time to restore that land to an agriculturally productive condition. It is far more preferable to follow the principle of prevention, to give careful thought to the consequences of land conversion and to make decisions that will preserve this vital resource for future generations. As articulated by Furuseth and Pierce (1982), there are many tools and options available, but these will not be used effectively without political will and widespread public support. A similar situation has been reported in Australia in a recent book chapter by Millar (2010).

We conclude that conversion of land from farming to other human uses continues today at a rate that compromises the capacity of the US and Canada to maintain agricultural production and food exports. Complicated by scarcity of fossil fuels and fresh water to help open new lands, the losses of the most productive lands near cities amplify the impacts of studies that merely quantify the number of hectares moving from agriculture to other uses. In addition to loss of production capacity, there is an alarming loss of ecosystem services on which humans and other species depend. We propose education as the primary route to creating widespread public awareness of the challenges, and urge citizens to become involved to create a political environment that will encourage enactment of policies to reverse the current trends. Our future economic and environmental well-being depends on these changes.

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FEE FOUNDATION *for* ECONOMIC EDUCATION

Saturday, July 01, 2000

Running Out of Agricultural Land

Have We Ever Run Out of a Nonrenewable Resource?

by Dwight R. Lee

Fear that we are running out of important resources is perpetual. Oil is a favorite thing to worry about; landfill space is another, and trees yet another. I could continue listing things (coal, copper, iron ore, even tin) that people have worried would soon be exhausted, and I plan to discuss the persistent fear of resource exhaustion in future columns. In most cases the fear is baseless—fueled by organized interests hoping to capture advantages by scaring the public, by sloppy journalism, and by a general lack of basic economic understanding. Where concern is appropriate, the problem is invariably the lack of private property rights in the threatened resource.

To see the role of property rights in preventing the depletion of resources, consider the following question: have we ever run out of a nonrenewable resource? I have asked dozens of audiences this question and have never found anyone who can name one. But aren't nonrenewable resources the ones we are most likely to run out of? After all, they are nonrenewable. More puzzling, we have run out of—driven to extinction—a number of animals, which are renewable. Aren't these the resources we should be least likely to run out of?. The puzzle is resolved by recognizing that nonrenewable resources just sit there; they don't run around, so it is easy to establish private property rights over them. As I discussed in earlier columns, people conserve resources they own by taking their future value into account. Many animals, because of their fugitive nature, are difficult to own as private property, and so people have little motivation to consider their future value. So despite their renewability, some of these animals have been extinguished.

Creating scares that we are running out of nonrenewable resources would be far more difficult if people understood the power of private property to motivate the proper consideration of our resources' future value. But in this column I consider another reason people mistakenly fear we are running out of, or dangerously depleting, resources—failure to distinguish marginal value from total value, a distinction I introduced last month.

Disappearing Farmland

I had just begun my first teaching job at the University of Colorado in 1972 when I was asked to participate in a debate on the "problem" of disappearing farmland. Despite my compelling arguments (several in attendance who agreed with me before the debate still agreed with me afterward) that decreasing farmland was the result of market forces working properly, concern over lost farmland has continued. For example, Lester Brown of Worldwatch Institute puts out an annual report predicting that food supplies will fall behind population growth, a problem he sees caused partly by the loss of farmland to development. In my local newspaper, columnist Tom Teepen recently warned, "Development is taking up farmland, forest and other open space in this decade at twice the rate of the 1980s . . . . Between 1992 and '97 some 16 million acres went to development."[1]

It is true that in the United States fewer acres are used for agriculture today than in the past, although the loss is far less than what Worldwatch and United States Department of Agriculture report.[2] But this "loss" of farmland is not a crisis or even a cause for concern. Instead, it is good news. First, with less land being used for farming, more land has reverted to open space and forest. You won't hear this from the crisis crowd, but there is more forestland in the United States now than 80 years ago.[3] Second, farmland has been paved over for shopping centers and highways, converted into suburban housing tracts, covered with amusement parks, developed into golf courses, and otherwise converted because consumers have communicated through market prices that development is more valuable than the food that could have been grown on the land.

Food or Golf

Why would consumers willingly sacrifice food for golf courses, shopping centers, and parking lots? Isn't food more valuable than golfing or parking? Of course—in total value. If the choice is between eating and no golf or playing golf but no eating, even the most avid golfer would choose eating. But economic choices are not all-or-none choices. Instead, we make decisions *at the margin,* deciding if a little more of one option is worth sacrificing a little bit of another. And at the margin it isn't clear that food is more valuable than golf or many other things we can live without. Golfers are communicating through greens fees that another golf course is at least as valuable as the additional food sacrificed.

At the margin, golf is certainly more valuable than food would be if millions of acres of farmland had not been "lost" to development. In 1900 most of the horsepower used on the farm was really horse power, or mule power, and tens of millions of acres were needed to grow the food for these animals. Trucks, tractors, harvesters, and other gasoline-powered farm machinery have efficiently substituted for these animals and the acres needed to feed them. Also, much less land is needed now to feed the same number of people because improvements in fertilizers, pesticides, irrigation, seeds, and weather forecasting allow more food to be grown per acre, and improvements in harvesting, packaging, storage, and transportation allow more of what is grown to get to the dinner table. If we still devoted as much land to farming as we did in 1900, with today's technology we would be knee-deep in cantaloupe. In this situation, how valuable would another few acres of cantaloupe be compared to another golf course that could be constructed on those acres?

We don't have nearly as much farmland as we did in 1900 because as food production increases, its marginal value decreases relative to that of houses, shopping centers, golf courses, and more. Consumers communicate this change in relative value with purchases that cause food prices to decline relative to the prices for other uses of farmland. This motivates a decrease in farmland that continues as long as the marginal value of land is greater in nonfarm uses than in agricultural production.

But don't expect the farmland "crisis" to disappear. Public agencies hoping for bigger budgets, and private organizations hoping for more research funding or larger subsidies, are always anxious to identify crises to scare the public. Crisis creation wouldn't be so easy if more people understood the difference between total value and marginal value. []

Notes

1. Tom Teepen, "Facts Justify Criticism of Suburban Sprawl," *Atlanta Journal and Constitution,* December 26, 1999, p. D4.
2. In chapter 2 of *Hoodwinking the Nation* (New Brunswick, N.J.: Transaction Publishers, 1999), the late Julian Simon gives examples of exaggerated claims by organizations, including the USDA, that benefit from the perception that farmland "loss" is a serious problem.

3. Gregg Easterbrook, *A Moment on the Earth* (New York: Viking, 1995), pp. 10-13.

Dwight R. Lee

Dwight R. Lee is the O'Neil Professor of Global Markets and Freedom in the Cox School of Business at Southern Methodist University.

14. Refer to the Application, Volume I, Appendix G, Figure 15, pages 29–32. Based on the Monte Carlo study and specific agriculture product study results, explain why farming should not be expected to disappear in Madison County.

RESPONSE: Farming should not be expected to disappear because the real profits per acre as shown in Figure 15 are dependent on agricultural prices. As shown in Figure 12 on page 18, the amount of land in farms in Madison County has been trending downward from 1990 through 2016. Although trending downward, farming should not disappear because the expected profits per acre should rise as the least profitable land exits agriculture.

WITNESS: David Loomis

15. Refer to the Application, Volume I, Appendix G, pages 33 and 35.

a. Explain the degree to which the JEDI model has been calibrated to Madison county, the regional economy (including how "regional" is defined), and the state economy.

b. Explain whether the degree to which the various elements of the solar project are manufactured locally, regionally, in Kentucky or imported from outside Kentucky or the region.

c. Explain how the JEDI model calibration parameters came from the Minnesota IMPLAN Group. If not, explain the source of the other calibration parameters.

RESPONSE:

a. The JEDI model is perfectly calibrated to Madison County and the Commonwealth of Kentucky. The model uses IMPLAN multipliers specific to Madison County for the county-level model and IMPLAN multipliers specific to the Commonwealth of Kentucky for the state-level model. We did not run a separate "regional" model for Madison Solar.

b. Although some of the items may in fact be sourced in Kentucky, we did not assume that any of the materials and equipment were manufactured or purchased locally. We assumed that 25% of the installation labor, business overhead and other costs were purchased in Madison County and that 50% of the permitting costs were spent in Madison County. At the state level, we again assumed that none of the materials and equipment were manufactured or purchased in the Commonwealth of Kentucky. We assumed that 50% of the installation labor, business overhead and other costs were purchased in the state and that 75% of the permitting costs were spent in the state.

c. The "calibration parameters" that came from IMPLAN were the economic multipliers specific to Madison County and the Commonwealth of Kentucky. IMPLAN provides a total of 546 sectors but the JEDI model divides the local economy into 22 different sectors. Before transferring the multipliers to the JEDI model, I use IMPLAN's aggregation feature to aggregate the 546 sectors into the 22 sectors required by JEDI.

WITNESS: David Loomis

16. Refer to the Application, Volume I, Appendix G, pages 35. Provide a listing of cost estimated and other project related assumptions provided by Acciona Energy.

[redacted]

WITNESS: David Loomis

17. Refer to the Application, Volume I, Appendix G, pages 36–37.

a. Explain how the model distinguishes between the construction and operational (annual) phases of the project.

b. Explain whether the correct interpretation of the Construction results in Table 6 are that Madison county will have an estimated increase of $13,210,187 in new local earnings over the long-term life of the solar project as a result of the short-term construction and installation activity. If the interpretation is incorrect, provide a correct interpretation of the results.

RESPONSE:

a. The model distinguishes between the construction and operational phases of the project by having separate cost inputs. The construction phase uses the upfront construction and development costs to measure the economic impact during the construction phase. The economic impact during operations measures the ongoing annual economic impact of the project using operations and maintenance costs.

b. The correct interpretation of Table 6 for Madison County would be that Madison Solar is expected to create or support earnings of $13,210,187 in total during the project development and construction phase of the project. An additional $425,536 in earnings would be created or supported each year in Madison County during the life of the project.

WITNESS: David Loomis

18. Identify where on KY-388 the expected locations of the entrances and exits to the construction site will be located.

RESPONSE: Please refer to the project site drawing, which is attached as Exhibit A.

- Access #1 designated as A1 in the project site drawing will provide access to the southwestern most parcel of the site. A1 departs from Lost Fork Road about 3,000 feet to the north of the intersection of Lost Fork Road with KY388.
- Access #2 designated as A2 in the project site drawing, will serve as South access to the main parcels of the site. A2 departs from Lost Fork Road about 600 feet to the north of Access #1.
- Access #3 designated as A3 in the project site drawing will provide access to a project small parcel on the east side of Otter Creek. A3 connects directly with KY388 about 200 feet north of the turnoff to the waste water treatment plant.
- Access #4 designated as A4 in the project site drawing will provide access to the parcels of the site situated East of KY 388. A4 connects directly with KY388 about 3,000 feet north of Access 3
- Access#5 designated as A5 in the site drawing will provide access to the project substation and to EKPC Point of Interconnection (POI) substation from Bill Eades Road about 900 feet north of the intersection with Cherry Trace Drive.
- Access #6 designated as A6 in the site drawing will provide access to the parcels situated to the southeast of the project site. A6 connects directly with KY388 about 100 feet to the north of the intersection of KY388 and Beaver Drive.

WITNESS: Jaime Saez Ramirez

19. Describe the signage or traffic signals that will be present near those entrances and exits.

RESPONSE: The need for signage and traffic signals has not yet been determined and may depend on a variety of factors. AEUG Madison will coordinate with the appropriate state and local officials to ensure appropriate signage and signaling is present.

WITNESS: Jaime Saez Ramirez

20. State how often traffic signaling is expected to be necessary to prevent any traffic issues.

RESPONSE: The need for traffic signaling has not yet been determined and may depend on a variety of factors. AEUG Madison will coordinate with the appropriate state and local officials to ensure appropriate signage and signaling is present.

WITNESS: Jaime Saez Ramirez

21. Please indicate the hours of the day the commuting construction workers will arrive and vacate the site during both the construction phase and when the anticipated morning and afternoon peaks will occur.

RESPONSE: The working hours on the site will be within sunlight hours. Work can happen 7 days per week. The anticipated morning peak will happen from 7 to 7:30 AM and the anticipated exit peak will happen approximately from 5:00 to 5:30 PM, in both cases during the weekdays.

WITNESS: Jaime Saez Ramirez

22. Please indicate the hours of the day the workers will arrive and vacate the site during the operational phase.

RESPONSE: Normal working hours will be from 7:00 – 3:30, Monday through Friday. There will be weekend on call coverage requirements where 1-2 technicians may be required to work on site to correct significant unplanned faults. Through the course of the year, we will perform preventative maintenance campaigns during night-time hours when the solar equipment is not generating. Two or three technicians will be performing this work in the solar field from dusk to dawn.

WITNESS: David Gladem

23. Please provide an approximate percentage breakdown of where the construction workers will commute from each day, if possible.

RESPONSE: The workers will commute from their houses or accommodation. It is not possible to anticipate at this stage from where the workers would commute.

WITNESS: Jaime Saez Ramirez

24. Please provide the weight classes of the vehicles anticipated to access the site daily during construction, as identified in Appendix C, Section 3, Table 3.2-1.

RESPONSE: AUEG Madison has not yet determined the weight classes of the vehicles anticipated to access the site during construction.

WITNESS: Jaime Saez Ramirez

25. Provide the expected maximum weight of the largest vehicles (including any materials or equipment that the truck is hauling).

RESPONSE: The largest vehicle will be the vehicle delivering the Main Power Transformer, with an estimated weight of 554,000 lbs (truck + transformer).

WITNESS: Jaime Saez Ramirez

26. If possible, provide an approximate breakdown by point of origin for the construction truck traffic.

RESPONSE: A specific breakdown of point of origin for construction truck traffic is not available at this time. Construction truck traffic will shift throughout the site as construction activities shift across the site. The highest volume of construction truck activity will occur at the site of the project substation as well as the operations and maintenance facility.

WITNESS: Jaime Saez Ramirez

27. State where the construction crew, supervisors and others will park on-site.

RESPONSE: The construction crew will park in the vicinity of the respective lay down areas. It is envisaged that there will be three main lay down areas. The main lay down area will be situated in the south of the main project parcel, and will be accessed through the A2 access. There will be a separate and smaller lay down area in the northwest of the project for the substation that will be accessed via access A5. There will be a second small lay down area that will serve the easternmost parcel of the project that will be accessed from access point A4. Please refer to the project site map, which is attached as Exhibit A.

WITNESS: Jaime Saez Ramirez

28. Refer to the questions propounded by Wells Consulting, which are attached as an Appendix to this information request, and provide responses to those questions.

RESPONSE: See responses filed as a separate response.

WITNESS: