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Federal Trade Commission
Solar Electricity Project No. P161200

Comments of Vote Solar in Response to the Questions for the Commission's June 21 Workshop

June 7, 2016

On April 12, 2016 the Commission notified interested parties that it will hold a workshop on June 21, 2016 in Washington DC to examine competition and consumer protection issues raised by consumers' growing use of rooftop solar panels to generate their own electric power. Vote Solar is interested in the issues to be discussed at the workshop and appreciates the opportunity to submit the comments below to the questions in the notice.

Vote Solar is a non-profit grassroots organization working to fight climate change and foster economic opportunity by bringing solar energy into the mainstream. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. We have staff in California, Colorado, Maryland, Massachusetts, and Washington, D.C. Over the past 24 months, Vote Solar staff have engaged in formal proceedings related to distributed solar generation in Arizona, Arkansas, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Minnesota, Mississippi, Nevada, New Mexico, New York, South Carolina, Utah, Vermont, and Wisconsin. Vote Solar is not a trade group or affiliated with the solar industry.

For expediency, we have grouped some questions together where appropriate.

Current State of the Solar Industry

The first set of questions address the growth of solar electricity generation, sources of growth, and the anticipated evolution of the industry. Vote Solar provides the following responses and resources to the questions.

- ***How much solar electricity was generated in the U.S. in 2015? How does that compare to 2005? 1995? How much solar generation can reasonably be projected for 2025?***
- ***Is the growth coming primarily from solar DG? Is growth in solar DG being driven by residential, commercial, or community installations? Are utility-scale installations of solar generation growing as well?***

Response

The attached presentation from the Solar Energy Industries Association ("SEIA") provides current data on the growth of solar photovoltaic ("PV") resources in the U.S.

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- ***How does the cost of solar DG compare with the costs of other sources of generation, including utility-scale solar installations?***

Response

The costs of PV systems in different market segments is reflected in the SEIA presentation. There are a couple of important points to make however in regards to cost.

First, solar PV is unique as an electricity generation technology in that it is extremely scalable. Installed solar projects can range in size from less than one kW to well over 100 MW. In comparison, residential solar systems in the 4-7 kW range can generate sufficient energy for a typical household's annual consumption (depending on the state and solar resource). As project sizes get larger, economies of scale in siting and construction can reduce installed costs significantly, although the same panels used in very large PV projects are used on homes and businesses. Major drivers of installed cost of small rooftop projects, outside of panels and inverters, are permitting costs and customer acquisition costs – i.e. the cost of marketing and sales.

Second, consideration should be given to who actually pays the cost of the projects of various sizes. Large "utility-scale" solar projects provide energy at wholesale to utilities of all types through purchased power arrangements. Contracts have different terms, pricing schedules, and other terms and conditions, negotiated by the signatories. Utility scale projects can also be built as turnkey projects, i.e. built by a solar developer and purchased by a utility. In these cases, the costs of the project (whether owned or through a PPA, are paid by the entire body of ratepayers of the acquiring utility.

Community scale projects (a.k.a. shared solar or solar gardens) are a more recent development in which a solar developer builds a centralized project in the sub-10 MW range typically, and sells subscriptions to retail customers of a certain utility. The subscribed energy offsets traditional energy purchases from the utility and the subscriber receives, virtually, its subscribed share of energy from the project, and pays for its subscribed share. Non-subscribers typically do not contribute anything towards the cost of these projects, except in cases where state promotional incentives exist. There are many flavors of the policies promoting these types of projects.

On-site solar projects are, as the name implies, constructed on the retail electric customer's premises – either on the building or ground-mounted. These systems can be as small as under 1 kW or as large as 2 MW. In rare circumstances, larger systems are allowed. Typical residential systems range from 2 kW to 10 kW, small commercial 10 kW to 100 kW, and larger commercial and industrial up to 2 MW. The home or business owner generally owns the system or leases the system from a third party. None of the costs of the system are paid by other retail customers of the utility. However, like solar gardens, there may be incentives in place to promote this form of distributed solar.

In the cases where incentives support the development of different forms of solar, it is important to separate any incentive costs from consideration of the metering arrangement with the utility.

- ***What are the cost components of solar DG? How fast is the cost of solar PV panels decreasing? What about installation costs? Are those costs likely to continue decreasing?***

Response

The Department of Energy's Sunshot program and the Lawrence Berkeley National Laboratory have issued many reports in regards to these questions.

- ***Does DG impose additional costs on the grid because of, e.g., changes in how the grid is used, integration costs, and/or overloading of local circuits? How can we calculate these additional costs?***

Response

DG can impose costs in the physical interconnection process with the grid. Most interconnection policies across the country however require the interconnecting customer to pay these costs with the goal that there is no cost impact on non-participating customers.

There can be costs associated with the integration of solar resources into the grid, for all scales of solar resources. The costs are modest however. Studies performed in Colorado and Idaho have found integration costs on the order of $1.00 to $1.50 per MWh, or about $0.001 to $0.0015 per kWh. In California, where more than one quarter of the three large investor-owned utilities' power mix is already renewable and solar served approximately 10% of the big utilities' total demand in 2015,[1] the California Public Utilities Commission has yet to determine a renewable integration cost over 0. Renewable integration costs can also be managed via strategies that allow demand to adjust to supply (for example, demand response and storage) and that allow electricity supply to be balanced across geographic regions.

Only in Hawaii, where customer participation rates are closing in on 20% and DG penetration is nearly 40% (based on capacity, i.e. MW), are there impacts of DG that need to be addressed. And while circuit by circuit penetration of solar resources is often limited to 15% (of peak load based on total capacity of solar on the circuit), some circuits in Hawaii have exceeded 250% -- meaning enough solar generation exists on the distribution circuits to push power up to the transmission level. In 40 of 50 states, DG penetration is below 1% and usually well below. At these very low penetration levels, there is no cost impact.

After Hawaii, the next highest penetration state is California, achieving about 5% statewide. There have been no impacts of consequence in this state. Therefore, we believe that a threshold exists somewhere between 5% and 35% at which regulators should take a closer look.

- ***Does DG save costs compared to other sources of generation because DG is placed more closely to the point of consumption? How can we value these cost savings?***

Response

Yes. DG reduces costs for the reason stated – electricity is generated at the point of consumption,

[1] See http://ww2.kqed.org/news/2016/01/11/solar-power-california-top-source-of-renewable-energy .

thus avoiding the transmission and distribution infrastructure necessary to deliver centrally generated power. In addition, there are savings due to avoided losses. Centralized power plants must generate approximately 10% more than is consumed because of losses due to heat along the way to the end user. However, there has been much study of costs avoided by deploying DG across the country. In 2013, the Rocky Mountain Institute (RMI) compiled a meta-analysis entitled "A Review of Solar PV Benefit and Cost Studies" of many of the avoided cost studies completed until that point.[2] It also analyzes each element of potential cost savings related to the deployment of DG and is an excellent resource.

When considering costs avoided, it is critical to understand the implications of the time period selected over which to examine such savings. For example, looking only at the costs saved immediately by installing DG will yield savings only related to the cost of *not* generating central station power – in other words the fuel that would have been burned (accounting for losses) and some variable operating and maintenance costs.

Consideration of longer-term costs avoided, as is done with energy efficiency evaluations and power plant planning, requires evaluation of investments that might have otherwise been made but for the DG. That is the subject of many of the "value of solar" studies performed around the country over the last five years or so. A recent paper[3] from the Brookings Institute summarized five recent studies sponsored by agencies of state government as follows:

> [b]y the end of 2015, regulators in at least 10 states had conducted studies to develop methodologies to value distributed generation and net metering, while other states conducted less formal inquiries, ranging from direct rate design or net-metering policy changes to general education of decision makers and the public. And there is a degree of consensus. What do the commission-sponsored analyses show? A growing number show that net metering benefits all utility customers:
>
> In 2013 Vermont's Public Service Department conducted a study that concluded that "net- metered systems do not impose a significant net cost to ratepayers who are not net-metering participants." The legislatively mandated analysis deemed the policy a successful component of the state's overall energy strategy that is cost effectively advancing Vermont's renewable energy goals.
>
> In 2014 a study commissioned by the Nevada Public Utility Commission itself concluded that net metering provided $36 million in benefits to all NV Energy customers, confirming that solar energy can provide cost savings for both solar and non-solar customers alike. What's more, solar installations will make fewer costly grid upgrades necessary, leading to additional savings. The study estimated a net benefit of $166 million over the lifetime of solar systems installed through 2016. Furthermore, due to changes to utility incentives and net-metering policies in Nevada starting in 2014, solar customers would not be significantly shifting costs to other ratepayers.

[2] See www.rmi.org/elab_emPower

[3] Muro, M and Saha, S, "Rooftop solar: Net metering is a net benefit," Brookings Institute, May, 2016.

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A 2014 study commissioned by the Mississippi Public Services Commission concluded that the benefits of implementing net metering for solar PV in Mississippi outweigh the costs in all but one scenario. The study found that distributed solar can help avoid significant infrastructure investments, take pressure off the state's oil and gas generation at peak demand times, and lower rates. (However, the study also warned that increased penetrations of distributed solar could lead to lower revenues for utilities and suggested that the state investigate Value of Solar Tariffs, or VOST, and other alternative valuations to calculate the true cost of solar.)

In 2014 Minnesota's Public Utility Commission approved a first-ever statewide "value of solar" methodology which affirmed that distributed solar generation is worth more than its retail price and concluded that net metering undervalues rooftop solar. The "value of solar" methodology is designed to capture the societal value of PV-generated electricity. The PUC found that the value of solar was at 14.5 cents per kilowatt hour (kWh)—which was 3 to 3.5 cents more per kilowatt than Xcel's retail rates—when other metrics such as the social cost of carbon, the avoided construction of new power stations, and the displacement of more expensive power sources were factored in.

Another study commissioned by the Maine Public Utility Commission in 2015 put a value of $0.33 per kWh on energy generated by distributed solar, compared to the average retail price of $0.13 per kWh — the rate at which electricity is sold to residential customers as well as the rate at which distributed solar is compensated. The study concludes that solar power provides a substantial public benefit because it reduces electricity prices due to the displacement of more expensive power sources, reduces air and climate pollution, reduces costs for the electric grid system, reduces the need to build more power plants to meet peak demand, stabilizes prices, and promotes energy security. These avoided costs represent a net benefit for non-solar ratepayers.

These generally positive PUC conclusions about the benefits of net metering have been supported by research done by a national lab and several think tanks. Important lab research has examined how substantially higher adoption of distributed resources might look.

The five referenced studies are available at:

Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, at 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

- ***What other benefits does solar DG provide to the grid? For example, does solar DG improve power quality, reliability, and/or resiliency? How can we value these benefits?***
- ***What are the environmental benefits and costs of solar power?***

Response

Please refer to the RMI report and the Brookings review of five studies referenced above for analysis of the spectrum of value components that can be considered in a benefits review.

We here provide a few examples from work we have done in a variety of states.

Enhanced reliability and resiliency

A grid with a large number of relatively small, distributed resources is inherently more reliable than a centralized grid that relies on a few large resources. In addition, DG enables the development of on-site backup (if DG is paired with storage) or can serve as the foundation for a local micro-grid that enhances reliability and resiliency

Disaster-recovery and backup benefits

Properly sited and configured DER can assist in the restoration of service after storm-related outages and power delivery component failures from other causes. Utilities often switch isolated feeder sections to alternate feeds at such times. Occasionally, there is insufficient capacity in the alternate feed to supply the load required to restore service to all consumers on the affected feeder section. The ability to support some of the load from DER output sited on the affected section may improve feeder reliability. If the DER can operate without the presence of the grid, they can be used to help restore power to sections of the distribution system that are completely isolated from the bulk power system (for example, as a result of storm damage). This is often referred to as a microgrid that can provide increased localized grid resiliency.[4]

Environmental and Public Health Benefits

Lawrence Berkeley National Labs recently released a study entitled "On the Path to SunShot: The Environmental and Public Health Benefits of Achieving High Penetrations of Solar Energy in the United States" that assesses three key potential environmental and health benefits of achieving the solar penetrations envisioned in the SunShot Vision Study: greenhouse gas (GHG)

[4] *The Integrated Grid: A Benefit-Cost Framework*, Electric Power Research Institute, February, 2015, p. 4-16

emissions reductions, air-pollution health and environmental impacts, and water-use reductions. The LBNL study finds the total monetary value of the GHG and criteria air pollution benefits of the SunShot Vision scenario exceed $400 billion in present-value terms under our central estimates, which is equivalent to roughly 3.5¢/kWh-solar.[5] (The study did not monetize the value of the water savings.)

The following information was drawn from joint comments submitted by Vote Solar and SEIA to the CA PUC, August 2015.[6] Societal benefits that accrue from renewable energy, both large-scale and renewable, include:

- Added benefits from reduced carbon emissions. Renewable resources avoid the short-term costs associated with complying with California's cap & trade program to limit GHG emissions. However, there are additional, longer-term benefits associated with avoiding the adverse impacts of climate change. These long-term carbon reduction benefits have been quantified most prominently in the federal government's social cost of carbon.
- Health benefits from reduced PM 2.5 and NOx emissions. Combustion of natural gas for electric generation is a source of particulate (PM 2.5) and oxides of nitrogen (NOx) emissions. The U.S. Environmental Protection Agency has quantified the health benefits of reducing the emissions of such criteria pollutants in California, as part of its Clean Power Plan.
- Water use. Thermal generation using fossil fuels consumes water for cooling. Although California is moving away from once-through-cooling using sea water, with its attendant impacts on marine environments, fresh water resources are used for cooling at gas-fired power plants. This water use can be avoided if DG displaces this thermal generation. Although the PT includes an avoided cost for water based on current water supply costs, we calculate an additional societal benefit based on the higher costs of avoiding the future need to develop new water supplies given that the state's existing water resources are fully developed.
- Land use benefits. DG is assumed to be able to use the built environment, avoiding the land use impacts of central station renewable projects. (specific to *distributed* renewable generation)
- Local economic benefits. The capital and operating costs of DG are higher than those associated with central station renewables. However, a portion of those added costs – primarily for installation labor, marketing, and permitting – is spent in the local area and thus provides additional benefits for the local economy. (specific to *distributed* renewable generation)

[5] The full study can be found at https://emp.lbl.gov/sites/all/files/65628.pdf
[6] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M153/K939/153939690.PDF

- ***What are the subsidies for solar DG at the federal and state levels?***

Response

The subsidies for solar DG at the federal level stem primarily from the recently extended investment tax credit and accelerated depreciation. This new ITC however ultimately declines and expires in 2022.

State incentives vary dramatically from state to state based on state priorities and maturity of the market. Some counties and local governments also provide incentives for the deployment of rooftop solar. One of the best sources of information related to incentives, particularly at the state level, is the "Database of State Incentives for Renewables and Efficiency."[7] It is operated by the North Carolina Clean Energy Technology Center at NC State University, is funded by the Department of Energy, and has been around since 1995.

The types of incentives available in states has ranged from tax incentives (e.g. investment or performance credits) to direct rebates and performance-based incentives. In many case, the incentives were designed to diminish over time as the market grew and installation prices declined. In a number of states, the incentive levels have declined to zero. This structure proved very effective in states like California, Arizona, and Colorado in launching and growing the rooftop market. The pay for performance approach usually used incentive funds to acquire renewable energy credits (RECs) or in the case of solar – SRECs.

It is important to keep the incentive programs that are or were available in many states separate from other policies such as net metering. It is clear that the incentive programs had a direct cost that is or was paid by taxpayers or ratepayers, including those that do not participate in the market. Net metering policies on the other hand are designed to allow a customer to offset grid-supplied energy immediately with on-site solar energy, and receive fair value for any excess energy (not consumed immediately).

- ***What other technologies (e.g., battery storage of solar-generated electricity) are relevant to the future of solar DG?***

Response

This is a great and very timely question. There are many new and emerging distribution-level technologies that will be used in concert with solar DG. In addition to battery storage which shifts energy supply from one period to another, there are demand response technologies that can shift load from one time frame to another, combined heat and power technologies like fuel cells, and efficiency technologies that can also be a form of demand response, like ice energy storage. There is also flexible load – load that can be moved to an appropriate time of day or night to balance supply – charging electric vehicles is a good example.

Another technology worth mentioning is so-called smart inverters. The inverter is the part of a solar generating system that converts the energy from direct current to alternating current and synchronizes it with the grid. Smart inverters, already in use in many places, have the ability to provide services to the grid including voltage and frequency regulation, and power factor support. Collectively, these are known as ancillary services and can also displace investments in

[7] www.dsireusa.org

certain types of equipment the utility would otherwise have to invest in to manage power across the grid.

California is on the regulatory forefront of addressing how to integrate all of these different technologies in a way that maintains grid reliability, enhances efficiency, and reduces cost, through a process known as *distribution resource planning* (the distribution analog to integrate resource planning which addresses generation and transmission needs).

Net Metering: Pricing Solar DG at Retail

- ***Is net metering good policy? At the retail rate? At a different rate?***

  Response

Net metering is good policy. It is easy for consumers to understand, allows instantaneous use of self-generated power, and provides fair value for exported energy. The "instantaneous use" part is like any other technology that affects load – the customer invests in a PV system or efficient light bulb, or electric vehicle and uses more or less electricity as a result. The utility, as a monopoly power supplier with a franchised service territory, has an obligation to serve the aggregated load of its customers as it may change over time. There is no obligation to buy.

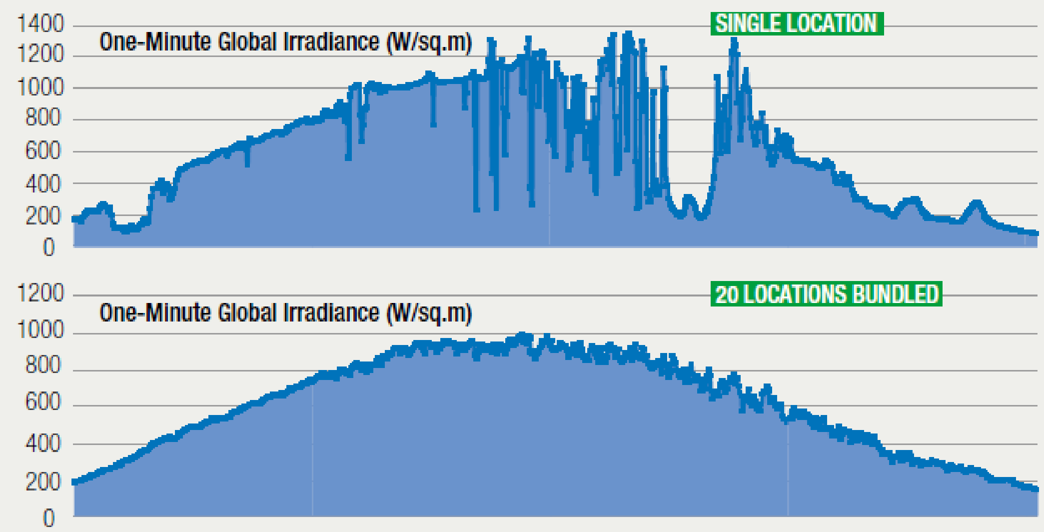
The second part of net metering is the netting. This is more controversial in that a customer generates power at one point in time and, through a meter that nets flows in each direction, is able to "use" that power at a later time. In reality of course, that excess power when generated flows a short distance to a neighboring house or business where it is absorbed by the nearby load. The neighbor does not see any difference in supply and does not know the source, and continues to pay the utility the full retail value of all its consumed energy, even thought the utility did not generate it, transmit it, and only played a very small role in delivering it. Because the outflows were paid by a nearby customer to the utility, and the reduction in demand and energy consumption (both near term and long term) has value to the utility, use of the retail rate for both inflows and outflows has been deemed as rough but fair compensation for excess generation.

Comprehensive view: The common example used, like the one above, tends to focus on the simplest and smallest systems such as those on homes. But net metering occurs on many different types of business from Walgreen's to Walmart, from 50 kW to 2 MW. Thus net metering policy should not be reviewed in a vacuum, but rather a comprehensive look across all customer classes is critical.

Geographic diversity: Comments may be submitted arguing that solar is an intermittent and unreliable resource. For example, several utilities have structured their cost-of-service models on the assumption that every kWh generated by a solar DG system requires one-for-one backup from the utility ignoring both diversity and value. But here too, the resource generation profiles need to be reviewed not one at a time but in the aggregate. The chart[8] below shows the smoothing effect of geographic diversity.

[8] Source: Public Utilities Fortnightly, Feb 2009

FIG. 1 REGIONAL DISPERSION AND RELIABILITY



Comparing the solar irradiance at one location on a single partly cloudy day (top) to that of 20 locations dispersed over approximately 100 square miles illustrates how system-wide distribution greatly reduces variability in solar energy.

Interestingly, utility scale solar generally does not exhibit the same degree of diversity even though it might be spread over a number of square miles.

- ***Does retail net metering result in cross-subsidization? For example, if the fixed costs associated with building and maintaining the electricity grid are incorporated into the price per kilowatt hour (volumetric pricing), do non-solar customers end up cross-subsidizing solar DG customers because the latter do not pay a full share of fixed costs when they choose to rely on self-generation?***
- ***Does cross-subsidization of one form or another always occur when retail rates are based only on volumetric charges and are time-invariant? Does cross-subsidization caused by net metering differ in any way from other forms of cross-subsidization inherent in regulated retail rates?***

Response

There are several ways to address this question. First is the issue of the types of differences that represent cross-subsidization. Second is whether any change in consumption results in cross-subsidization. Finally, assuming the retail rate accurately reflects costs, then how does it stack up against the benefits provided by the solar DG system. All the while, we urge the Commission to keep in mind that any excess generation is paid for by a neighboring customer at the retail rate.

<u>1. What is cross subsidization?</u> Because electricity rates are based on a total revenue requirement that is allocated to large customer classes (e.g. residential, commercial, industrial) based on characteristics of the entire class, no single customer pays bills that match the precise costs of serving that customer particularly when, as the question highlights, rates for residential and small commercial customers are nearly all time-invariant (addressed

in response to the next question). In very rough terms, residential customers that have higher than average use pay more towards fixed costs than do customers with lower than average usage. At the same time, that first group of customers may impose higher costs than the second group.

Here are some common examples of cross subsidies inherent in regulated retail rates of typical utilities today:

- **Multi-family** subsidizes **Single-family**; an apartment building is served by a single transformer bank, and the utility never sees the individual demand of individual units – only the consolidated demands of the group. Yet, a large apartment building, under high fixed charge rate design, will pay much more than an otherwise identical-to-serve load (undiversified and coincident kW, monthly kWh, hourly usage patterns) at a hotel or office building served through a single meter. Multi-family is less expensive than single family, due to the wider sharing of transformers and the service drop, the large number of customers per span of primary distribution, load diversity, and lower meter-reading costs (for utilities without remote metering).
- In new single-home residential areas, the distribution system is generally sized based on the expected usage of the homes in the area (with simple adjustments for square footage and electric appliances), not on the expected usage of any one home (e.g., recognizing the efficiency of the home and the appliances). Line extension policies generally provide for a larger line extension investment by the utility if expected usage is higher. New customers with expected low usage are generally required to pay a significant part of the line extension. The allowances are typically based on expected usage or expected revenue. Therefore, the investment by the utility in distribution systems is generally tied to expected sales. To recover these costs uniformly on a per-meter basis will double-charge customers who have paid a contribution in aid of construction for their line extension.
- In an established residential area, increased consumption requires increases in the number and size of line transformers, in the number and size of distribution lines, and in the transmission and substation facilities serving. Increases in consumption can be due to:
    - New appliances and technologies, from home entertainment to added refrigeration and freezer space, to electric vehicles.
    - Expansion of existing homes.
- System costs are not uniform across all customers, yet postage-stamp rates charge the same rates to all customers.
    - Customers served with (cheaper) **overhead** distribution subsidize customers served with (more expensive) **underground** distribution, who actually receive more reliable service (fewer outages due to storms, treefalls, vehicles, animal contact). Depending on the utility, overhead distribution may be primarily located in more affluent suburban areas, with most low-income customers served by underground service in urban centers; alternatively, undergrounding may be found mostly in recent higher-income suburban developments, with overhead in less affluent areas.

- Line losses vary with the distance from the distribution substation to the customer, the loading on the line, the peak-concentration of the load, and the location of the substation on the transmission system, but utilities charge all customers in a rate class the same loss factor.
- The distance from a distribution substation to a large customer may affect the amount of equipment (and investment) required of the utility to serve that customer, yet postage-stamp rates charge the same rates to all customers.
- **Urban** customers generally subsidize **suburban** and **rural** customers, since a mile of distribution serves more urban customers than suburban customers, and rural distribution serves even fewer customers per mile.

2. Does *any* change in consumption result in cross-subsidization? Existing residential and small commercial customers who reduce their energy contribute less revenue towards fixed cost recovery than those using more, but contribute less to the need for new transmission and distribution capacity, extend the lives of the transformers and underground lines that serve them, reduce the need for new generation resources, allow retirement of existing resources, and lower competitive market prices for energy and capacity. Consumption reductions can be due to:

- Behavioral and lifestyle changes, e.g., adding children, housemates or aging parents to the household; working a business from home. Expansion of internet-based businesses and telecommuting can fundamentally change the load and load shape of residential customers from what existed when the circuit was constructed.

3. What about cost and benefits? If we assume the retail rate accurately reflects costs, and those costs are not collected from solar DG customers, then it seems a straightforward matter to calculate the benefits provided by the solar DG system and compare the two. This is just what was done in the five studies reviewed by Brookings above. Indeed, benefits outweighing costs indicates solar customers are subsidizing non-solar customers.

Because net metering costs and benefits vary by utility; the only accurate way to answer this question is case by case, by conducting a comprehensive cost-benefit analysis for a given utility or state that includes societal benefits. In California, Vote Solar and allies conducted one such comprehensive analysis in 2015 using a CPUC-approved spreadsheet tool, and determined that preserving net metering for the 3 large IOUs would create annual net benefits to all ratepayers of $900 million per year. (Aug 3 proposal, p.i)

Table ES-1: *Key Metrics from the Solar Parties' Base Case (new systems, 2017-2025)*

Perspective	Benefit-Cost Ratio	Annual Net Benefits ($ millions per year)
All ratepayers	1.45	$900
Societal: California as a whole	1.76	$1,680
Ratepayers who install DG	1.44	$755
Non-participating ratepayers	1.04	$110

- ***Does it make sense for PUCs to target net metering for reform, or should they focus on reforming retail rates more generally to better reflect the varying costs of supplying electric power?***

Response

There are several aspects of electric utility regulation that are ripe for reform, beginning with the utility business and regulatory model. The management of electric utilities is driven by a regulatory model that hasn't changed much since its inception. This "cost-plus" model provides dollar for dollar recovery of expenses plus a return on the assets in which the utility invests. From the utility's perspective then, the only way to grow the Company and increase dividends for shareholders is to invest in assets – generation, transmission and distribution assets. This incentive has even been given an economic term – the Averch-Johnson effect. In layman's terms:

> The Averch–Johnson effect is the tendency of regulated companies to engage in excessive amounts of capital accumulation in order to expand the volume of their profits. If companies' profits to capital ratio is regulated at a certain percentage then there is a strong incentive for companies to over-invest in order to increase profits overall. This investment goes beyond any optimal efficiency point for capital that the company may have calculated as higher profit is almost always desired over and above efficiency. Excessive capital accumulation under rate of return regulation is informally known as 'gold plating'.[9]

Any regulatory policy that leads to lower load growth (e.g. energy efficient equipment or solar DG) reduces the need for new generating and transmission assets in particular and is anathema to rate of return regulated firms. The concerns of utilities regarding the impacts of solar DG and other demand-side management (DSM) technologies were expressed in the "Disruptive Challenges" report released in early 2013 by the Edison Electric Institute (EEI):

> While the various disruptive challenges facing the electric utility industry may have different implications, they all create adverse impacts on revenues, as well as on investor returns, and require individual solutions as part of a comprehensive program to address these disruptive trends. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality.[10]

As long as utilities and utility shareholders are rewarded for asset acquisition, and not operating in concert with the goals of the population, there will continue to be little innovation driven by the incumbents. As a result, innovation is dominated by outside firms that develop and install all forms of distributed technologies that provide benefits to customers and the utilities alike. These benefits include improved grid resiliency and security, efficiency, ancillary services, lower cost, and the like. In order to provide these benefits however, the innovators must respond to the price

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[9] Source: https://en.wikipedia.org/wiki/Averch%E2%80%93Johnson_effect

[10] Kind, Peter, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business," prepared for EEI, Jan 2013, from the executive summary.

signals that utility customers receive from the regulated firms. Hence the focus in recent times on "rate reform."

Electric utility rates have evolved over a long period of time and much has been written on the subject. The Godfather of designing sound rate structures is Professor James Bonbright who developed generally applicable criteria for designing rates in 1961.[11] These criteria are still referenced today (See Consumer Union's "Caught in a Fix").[12]

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers . (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different customers Avoidance of "undue discrimination" in rate relationships.
7. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    (a) in the control of the total amounts of service supplied by the company;
    (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

Rate reforms that have been, and are being, discussed around the country often look to the Bonbright criteria as guiding principles. In our experience, the incumbent utilities focus heavily on criteria 3 and 4, often to the exclusion of the first criterion. We have also seen many of the proceedings initiated by investor-owned utilities lack sufficient data to demonstrate that an actual problem exists that needs to be solved. As discussed above, a reduction in revenue resulting from DER technologies (or behavioral changes) does not automatically lead to the need for rate reform.

A good example has been the recent push in a variety of states (e.g. NV, AZ, CO) for the application of demand charges to residential customers. Demand charges are a rate form that ties recovery of fixed costs to the single highest load (usually during a 15 minute period) of a customer during a billing month. This rate form is commonly used for large customers whose loads tend to be stable and consistent, and often have energy or facilities managers whose job in part at least is to manage electricity consumption and peak loads. Small customers on the other hand are not as sophisticated and will create a peak demand simply by running the wrong appliances at the same time, or plugging in an electric vehicle for recharging.

There is general agreement among all stakeholders that rates should reflect costs, and that to the

[11] Bonbright, James, *Principles of Public Utility Rates*, pp. 290-291,1961 (First Edition).
[12] Melissa Whited et al., Synapse Energy Economics, Inc., *Caught in a Fix: The Problem with Fixed Charges for Electricity* (2016).

extent possible, the timing of pricing should reflect the timing of cost incurrence. Time varying pricing that is connected to established periods of higher and lower system loads will provide customers with a clear financial incentive that is actionable. Demand charges simply cannot do that. The Regulatory Assistance Project has released some excellent reports in this area, notably "Smart Rate Design for a Smart Future."[13]

- ***Is there a way to prioritize among various reforms? Potential reforms may include a "value of solar" tariff; dual metering/net metering at something other than the retail rate; fixed charge reforms; smart meters/time-variant pricing.***

  Response

Vote Solar believes that looking first to rate reform "puts lipstick on the pig." As long as the regulatory model rewards incumbent utilities for asset acquisition, utilities will work to limit innovation and technology deployment that can result in a cleaner, more efficient utility system albeit one that is not 100% owned and controlled by the incumbent.

In parallel, regulatory bodies should be looking at planning processes described above that integrate various forms of DER technologies with the goals of reliability, efficiency, security, sustainability, and environmental soundness. At that point, commissions should begin to look at reforming policies and rates to encourage and optimize the goals of the State. The potential reforms noted in the question are being examined in one or more states, the living laboratories, in typical one-size-does-not-fit-all fashion.

Prioritizing among potential reforms requires a set of principles against which to measure outcomes and success. Vote Solar has developed guiding principles in concert with other nonprofit advocacy organizations for distributed solar generation as follows:

1. Preserve individual customers' rights to self-determination: Each customer can choose the amount of energy to purchase from the grid, the amount to self-produce and consume, and the amount to save through efficiency measures that reduce consumption.
2. Capture the full range of DSG benefits and values: Customer-sited solar generation offers many benefits to the electric utility system and by extension to non-solar customers. The values and benefits should be quantified, and solar customers should be adequately compensated for the value their solar energy is delivering to all customers
3. Promote policies and rates favorable to next generation distributed technologies: Regulatory policies and electric rate design should not inhibit the deployment of DSG, demand response, combined heat and power (e.g. fuel cells), storage or other innovative technologies that are currently available or will be available in the foreseeable future.
4. Insist upon non-discriminatory rate practices and policies: Utility rates should treat reductions in energy sales and utility revenues due to net metered solar and other DSG in a manner that is fully comparable to, and non-discriminatory relative to, reductions due to other consumer behaviors including energy efficiency and demand response.

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[13] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future.* Montpelier, VT: Regulatory Assistance Project. http://www.raponline.org/document/download/id/7680

5. Due process is essential: Facilitating the deployment of distributed solar generation is critical for developing the energy structure of the future. Thus, it is of paramount importance that DSG rate policies be determined in regulatory forums guided by the rules of law where stakeholders have access to transparent and verifiable data.
6. Ensure that the benefits of rooftop solar are shared with low-income customers: Within resource and grid planning processes, regulators must ensure that utilities effectively realize the present and future benefits that distributed solar provides in terms of freeing up capacity on the distribution and transmission system and reducing the need for infrastructure upgrades. These cost savings must be equally shared among all ratepayers, including low-income ratepayers, through thoughtful rate design. [14]

- ***Does the analysis change when the distribution utility is vertically integrated? When the utility is investor-owned, municipally-owned, or a co-op? When consumers have retail choice? When retail pricing is time-variant?***

  Response

The analysis does change in terms of the market players and the realization of the benefits identified in the cost-benefit analyses. In other words, while the underlying inputs don't change, the traditional investor in the assets whose costs are avoided will vary. For example, an unbundled cost-benefit analysis will not show uniform b/c ratios across each function, i.e. generation, transmission, and distribution, but in total the results should be substantially the same.

- ***To what extent does the optimal approach depend on penetration levels for solar DG?***

  Response

The optimal approach very much depends on penetration levels for solar DG, taking into account the goals of the State. Most states have very low penetrations of solar DG resources currently, and most are seeking to encourage the growth of the resource. But the blunt instrument of rate reform policies incumbent utilities are seeking undermines the economics of on-site solar generation to slow or stop deployment, often before it can even begin to grow. Vote Solar supports a policy that establishes appropriate threshold for review of the retail solar market tied to penetration levels. As discussed early in these comments, an initial review should occur when penetration levels reach between 5% and 10%, as measured by total distributed generation capacity (AC, alternating current) to system peak load.

- ***Should environmental externalities affect retail pricing?***

  Response

Many environmental costs have already been internalized, and with implementation of the Clean

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[14] *See Guiding Principles: Distributed Solar Generation Policy & Rate Design*, available at http://votesolar.org/policy-guides/rooftop-solar-policy-guides/guiding-principles/.

Power Plan, the cost of carbon will join that group across the country. Some individual states have been including what some might consider externalities for some time, particularly in resource planning processes. These considerations affect retail pricing by giving greater weight to cleaner resources.

For solar DG, externalities are sometimes considered as part of the cost-benefit analyses discussed above. These values add to the total value provided by solar DG and can, and should, be compared to retail rates (the cost side of the equation). If the benefits exceed the costs, or they are close, there is no need for a move away from the simple policy of retail rates as the effective value of the solar resource. If the benefits fall far short of the costs, then alternative pricing can be considered.

Competition Issues

- ***Is solar DG a competitive threat to distribution utilities? Does this depend on whether the distribution utility owns generation assets?***

  Response

Solar DG is clearly a competitive threat to vertically integrated utilities, as described above and noted in EEI's *Disruptive Challenges* report. However the threat is primarily one of regulatory paradigm. Few would suggest today that some combination of DER technologies can fully replace the utility but clearly there are future generation and transmission assets investments that can be avoided. This is good for all consumers.

For distribution utilities, DER technologies, including solar DG, should be a benefit as new technologies can perform some distribution functions at lower cost. Again, the regulatory return on rate base model skews the motivations of incumbents, and should be reformed. A robust, efficient and reliable distribution network is in everyone's best interest.

- ***How does regulation affect entry decisions by solar DG firms? What regulatory policies support or discourage entry?***

  Response

Solar DG firms are relatively new market entrants and are very sensitive to the risks posed by regulatory uncertainty. The current rate structures drive the economics for many solar businesses and their maintenance in roughly the existing format allows meaningful market entry. Conversely, the rate redesign proposals initiated by utilities across the country that generally seek to recover costs on more of a fixed, i.e. unavoidable, basis creates an escalated level of uncertainty. This is amplified when states make sudden, major shifts in policy. For example, the Nevada PUC reformed rates earlier this year to triple the monthly fixed charge and to reduce compensation for exported solar energy by 70%. This has a huge impact on the economics of prospective customer-sited solar by itself, but it went further and applied these rate changes to the 17,000 or so customers that had installed solar DG over the prior 15 years. The combination of these two policy changes drove many solar companies, and thousands of jobs, out of the Nevada market. A Governor-led task force has since recommended to the legislature that it take up a bill to allow existing customers be grandfathered under the prior rate regime.

Another example is the Salt River Project, a large unregulated utility in Arizona. It adopted rates that include demand charges in early 2015 and saw applications for solar DG interconnections drop 95%.

Incumbent utility rates that impose fixed charges on customers discourage all forms of new technologies, including those that would make generation and consumption more efficient.

- ***Are there barriers to entry not related to regulatory policies? If so, is antitrust enforcement an appropriate tool to address them?***
- ***If regulatory policy affects entry conditions, is there a role for antitrust enforcement or competition advocacy to encourage entry? Is antitrust an appropriate tool to police efforts by utilities to maintain or strengthen regulatory barriers to entry from solar DG firms? Can such efforts by utilities be characterized as exclusionary conduct under the antitrust laws? Or is regulation the preferred tool to shape electricity distribution going forward? Are regulated distribution utilities protected from antitrust suits through any immunity or exemption? Should they be?***

Response

These questions are best answered by the solar industry.

- ***Should utilities be permitted to offer rate-paying customers utility-supplied solar PV panels or access to community solar installations? Does it make a difference if, instead, it is an unregulated subsidiary or affiliate of a regulated utility that is offering the solar PV panels? Are anti-discrimination rules for utility affiliates effective in achieving a competitive landscape?***

Response

Vote Solar believes utilities should be allowed to fairly compete in the marketplace for DER technologies, but not at the expense of undermining competition from other entities. As suggested in the question, it is far cleaner for an unregulated subsidiary of a utility to be the entity that is entering the marketplace, but even then, effective firewalls must be in place to assure separation of the information and assets of the regulated firm from the subsidiary.

It does make a difference whether the firm is regulated or unregulated. For example, Public Service Company of Colorado is currently asking the Colorado PUC to approve a new <u>regulated</u> solar program that has all the earmarks of a Community Solar Garden (CSG), but does not abide by the limitations and encumbrances placed upon CSG by statute. In Colorado, CSG must be no larger than 2 MW, must be located in the same or an adjacent county as the subscriber, must provide for low-income subscriptions, and can sell any unsubscribed energy to the utility at an annual average incremental cost rate. The program proposed by the utility seeks to build a project up to 50 MW in size, to sell subscriptions anywhere in its service territory which covers a large part of the state, makes no provision for low-income customer access, and charges non-participating customers at a rate it says reflects the value provided to the system by the solar energy. This value, with which we agree by the way, is approximately three times the rate that

CSG developers receive. To add insult to injury, the utility claims that as a regulated program, its employees marketing the program will have full access to its customer information data base.

We wholeheartedly support more solar businesses and program models in the market, but not through anti-competitive programs or actions at the expense of existing companies.

- ***What is the state of competition among solar DG firms? Are there geographic areas where competition is particularly lacking between solar DG firms?***

  Response

Most states that have developed solar DG markets largely through the policies under review herein are on the right track to have enough players to provide for competitive bidding at the residential level and above. These markets should be allowed to continue to evolve until the appropriate thresholds for review can be reached.

- ***What is the state of competition between solar DG firms and regulated utilities? How is competition affected by whether the utility offers distribution service only, electricity supply only, or both?***
- ***How is this competition affected by the fact that regulated utilities earn revenues that are based, in part, on regulated rates of return?***

  Response

These questions are largely addressed in previous responses that discussed the regulatory rate of return model and the anti-competitive approaches proposed in some states both in rate design and new programs.

- ***How do consumer protection issues such as comparative price information or disclosures of regulatory risk affect competition among solar DG firms and competition between solar DG firms and utilities?***

  Response

This question is best answered by the solar industry.

VOTE SOLAR

Vote Solar thanks the Commission for the opportunity to address these highly important issues and look forward to the workshop on June 21. Please let us know if there is more information we can provide to assist in your review.

Respectfully submitted June 7, 2016.

/s/ *Rick Gilliam*

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Vote Solar Colorado Office
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rick@votesolar.org

Additional Resources

Rate Design Papers and Technical Articles

CERES: *Pathway to a 21st Century Electric Utility*, Peter Kind:
http://www.ceres.org/resources/reports/pathway-to-a-21st-century-electric-utility/view

Consumer's Union: *Caught in a Fix*: http://consumersunion.org/research/caught-in-a-fix-the-problem-with-fixed-charges-for-electricity/

Electricity Journal
Moving Towards Demand-based Residential Rates, Scott Rubin, Nov 2015
Legal Case against Standby Rates, Casten & Karegianes, Nov 2007

E source survey: *Net Metering Wars: What Do Customers Think?*:
http://b.3cdn.net/solarchoice/27dbacad2a21535d4c_78m6ber2o.pdf

IREC DG Cost/Benefit Manual: http://www.irecusa.org/publications/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

Natural Gas and Electricity Magazine: *Residential Demand Charges*, February 2016:
https://www.researchgate.net/journal/1545-7907_Natural_Gas_Electricity

North Carolina Clean Energy Technology Center
Rethinking Standby and Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar Cost Reductions, August 2014: https://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_V2.pdf

Regulatory Assistance Project

- Smart Rate Design for a Smart Future: https://www.raponline.org/document/download/id/7680
- Teaching the Duck to Fly: https://www.raponline.org/document/download/id/8043
- Designing DG Tariffs Well: http://www.raponline.org/document/download/id/6898
- *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs:* ***http://www.raponline.org/document/download/id/7361***
- *Time-Varying and Dynamic Rate Design:* ***http://www.raponline.org/document/download/id/5131***

Utility Dive

- *Survey: State of the Electric Utility 2016*: http://www.utilitydive.com/library/state-of-the-electric-utility-2016/
- Articles by Jon Wellinghoff and James Tong:

- *Why fixed charges are a false fix to the utility industry's solar challenges*: **http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/**
- *A common confusion over net metering is undermining utilities and the grid*: **http://www.utilitydive.com/news/wellinghoff-and-tong-a-common-confusion-over-net-metering-is-undermining-u/355388/**
- *Are fixed charges a curse in disguise for investor-owned utilities?*: **http://www.utilitydive.com/news/tong-and-wellinghoff-are-fixed-charges-a-curse-in-disguise-for-investor-ow/378648/**

Relevant Decisions and Testimony

Arizona: UNS Rate Case E-04204A-15-0142 (Note key ACC Orders attached to Surrebuttal)
Direct Testimony: http://images.edocket.azcc.gov/docketpdf/0000167223.pdf
Surrebuttal Testimony: http://images.edocket.azcc.gov/docketpdf/0000168409.pdf

California:
Residential Rate Redesign: http://www.dra.ca.gov/general.aspx?id=2444
PUC Decision re PG&E Option R:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF
2016 PUC Decision Extending Net Metering:
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

Hawaii: KIUC: http://www.utilitydive.com/news/hawaii-puc-approves-solar-tou-rate-pilot-for-co-op-kiuc/406249/

Idaho: Idaho Power Company, Final Order IPC-E-12-27:
http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1227/ordnotc/20130703FINAL_ORDER_NO_32846.PDF

Illinois: Cost of Service for Low Use Customers, Docket No. 14-0384
Direct Testimony, 12/4/14: https://www.icc.illinois.gov/docket/files.aspx?no=14-0384&docId=222283
Rebuttal Testimony, 4/7/15: https://www.icc.illinois.gov/docket/files.aspx?no=14-0384&docId=227470

Minnesota: Chernick Rebuttal Testimony, Docket E002/GR-13-868, July 7, 2014:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={3EF78D2D-E8B8-4B9F-BDC7-5B94587BCCFA}&documentTitle=20147-101254-02

Texas, El Paso Electric: http://www.utilitydive.com/news/el-paso-pushes-texas-regulators-to-scale-back-utility-rate-hike-reject-new/411002/

TRENDS IN SOLAR PRICING AND STATE POLICIES: A BASELINE FOR CONSUMER ADVOCATES

Sean Gallagher, VP State Affairs
Solar Energy Industries Association

June 2, 2016

About SEIA

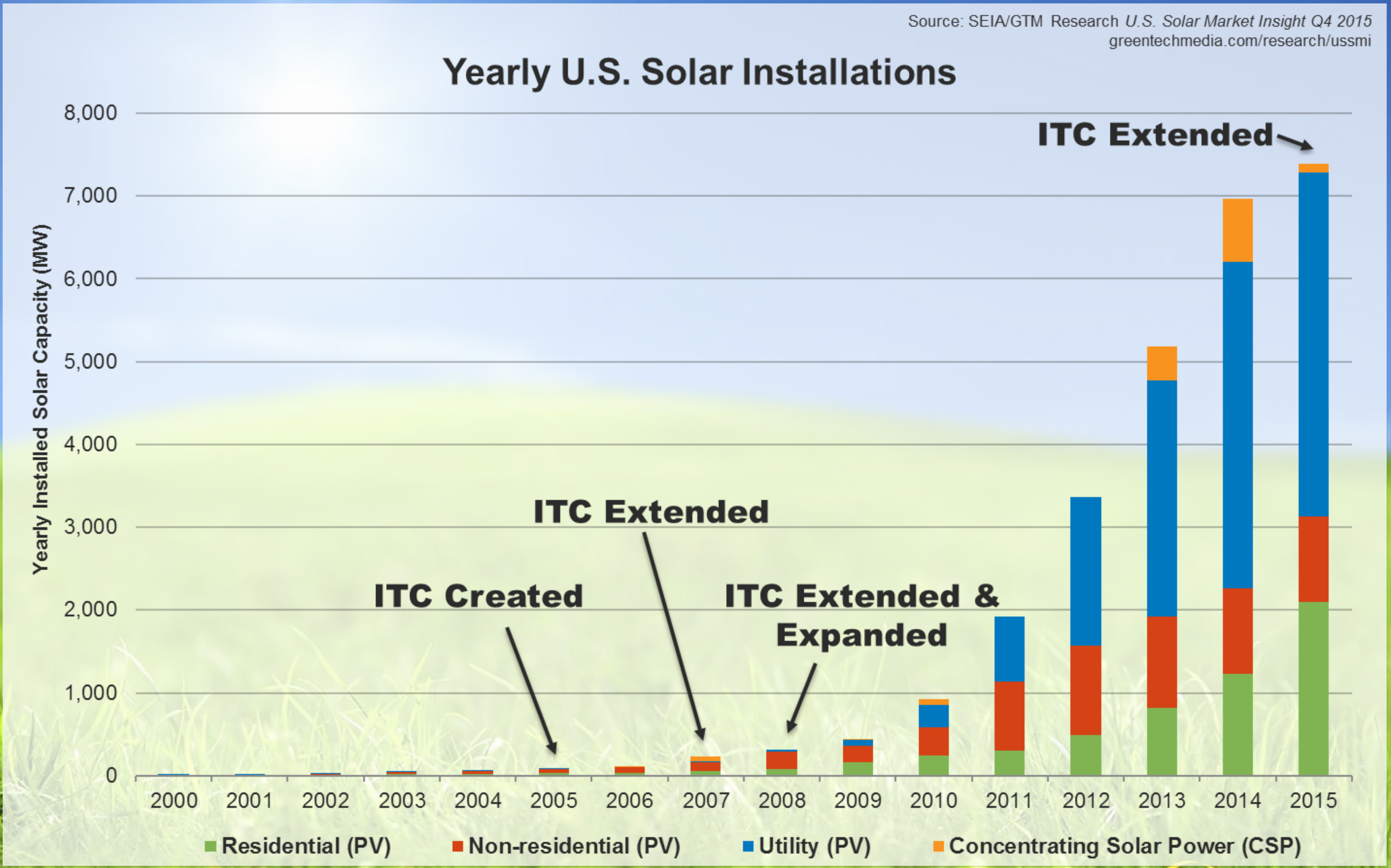
- U.S. National Trade Association for Solar Energy
    - Founded in 1974
    - 1,000 member companies from all 50 states
- Our Mission: Build a strong solar industry to power America
- Our Goal: 100 gigawatts of solar capacity by 2020

SEIA Solar Energy Industries Association®

Agenda

- Solar market statistics
- Distributed generation policies and trends
- Utility scale solar policies and trends

Solar Growth



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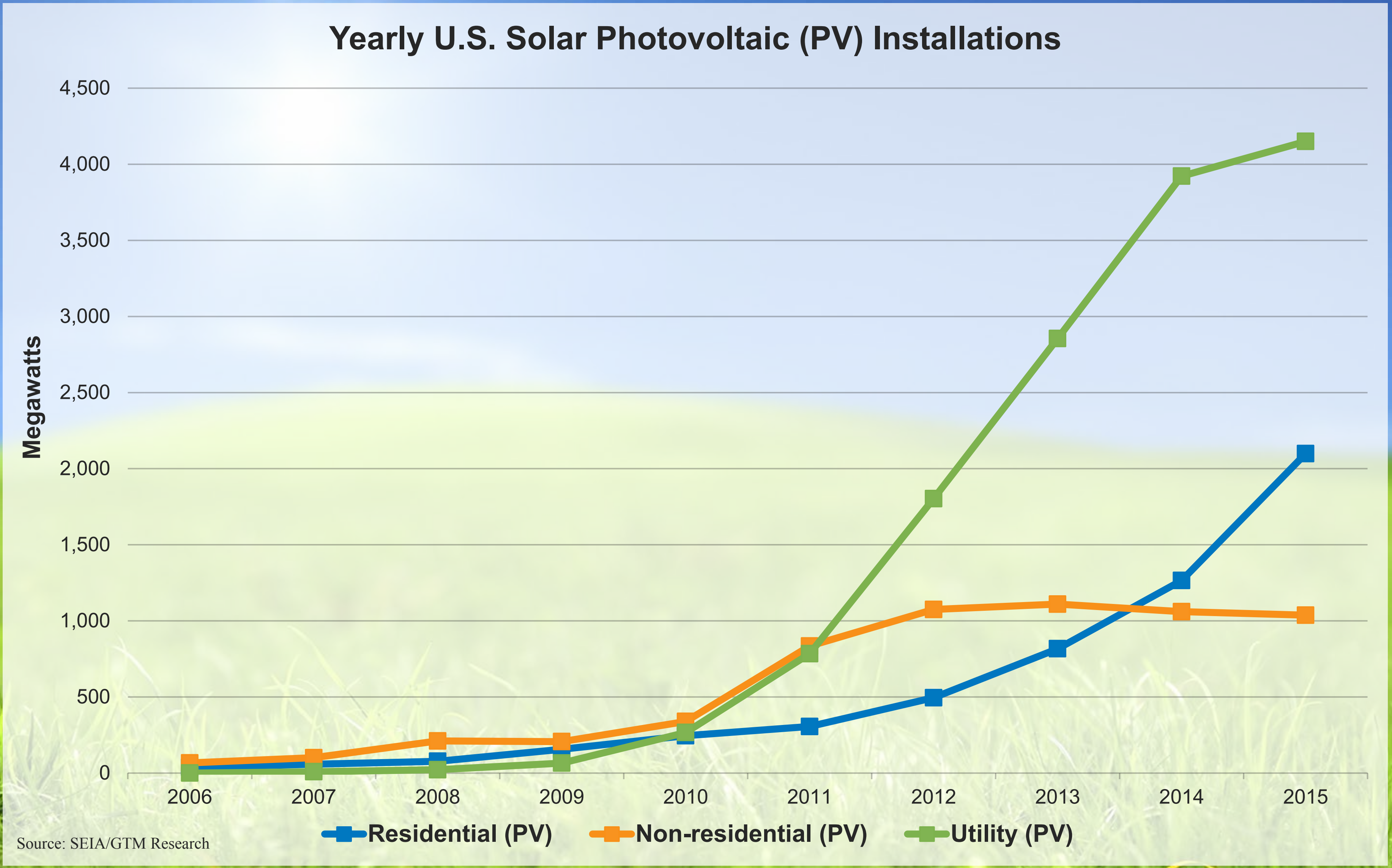
Solar Growth by Market Segment



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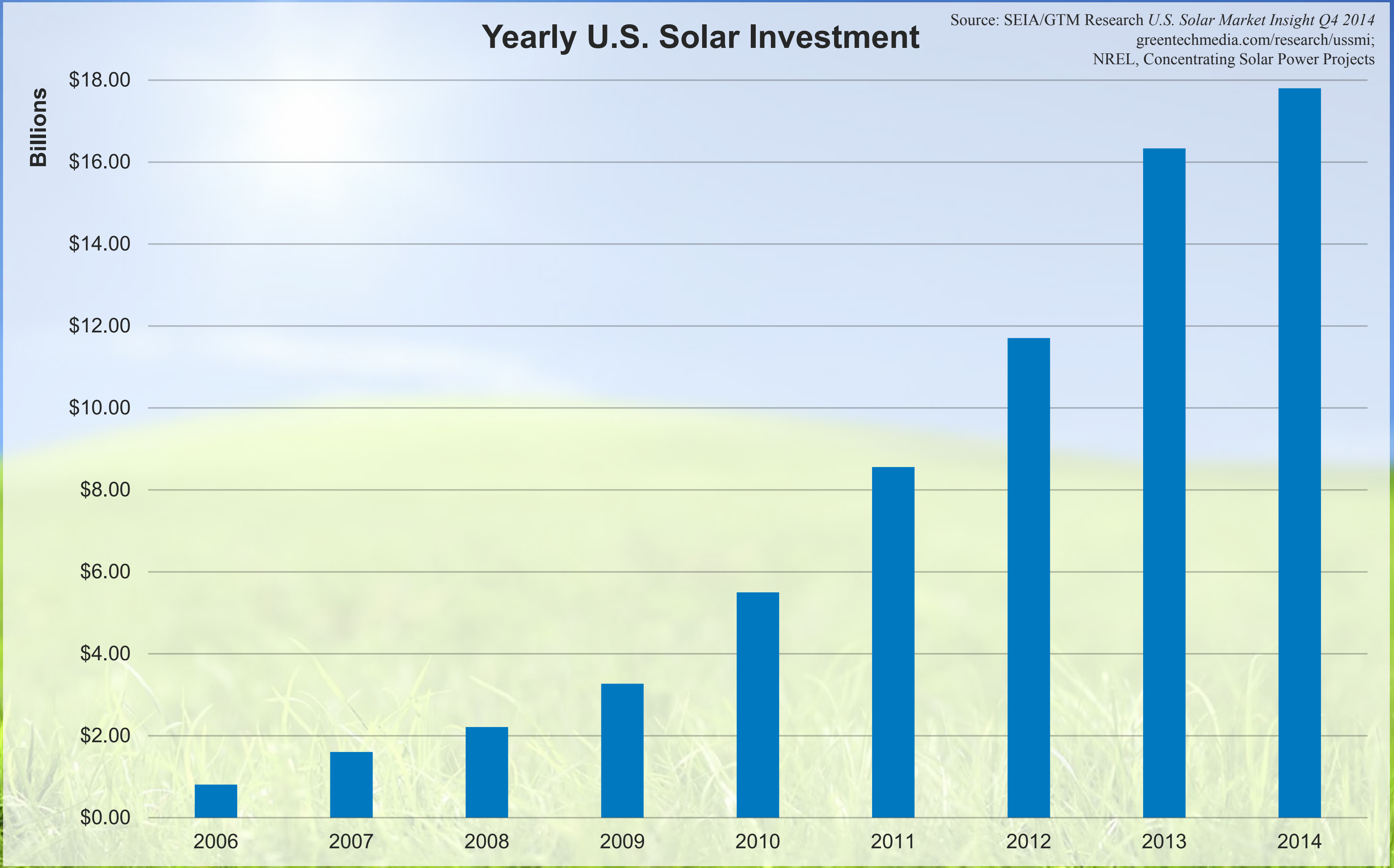
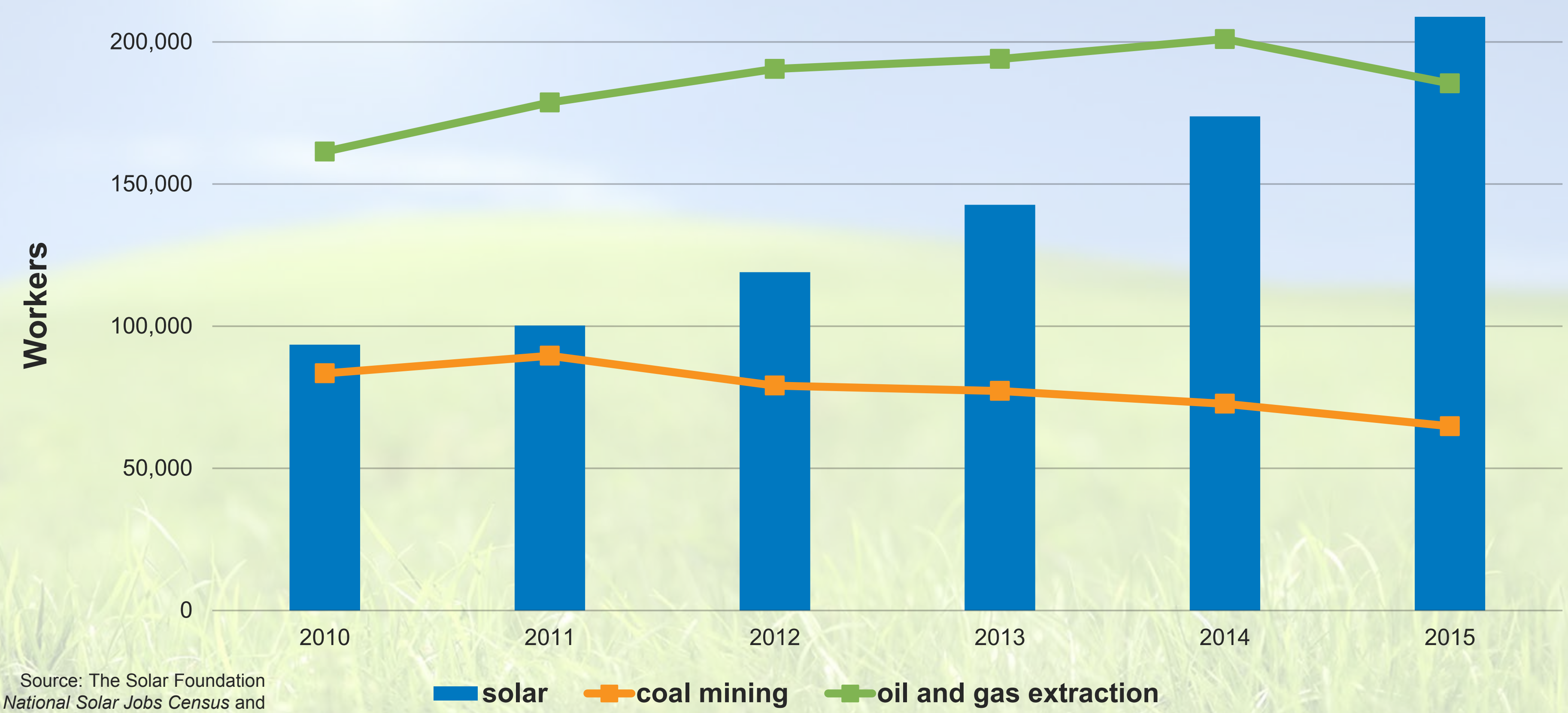
Investment in Solar has increased 10x since 2006



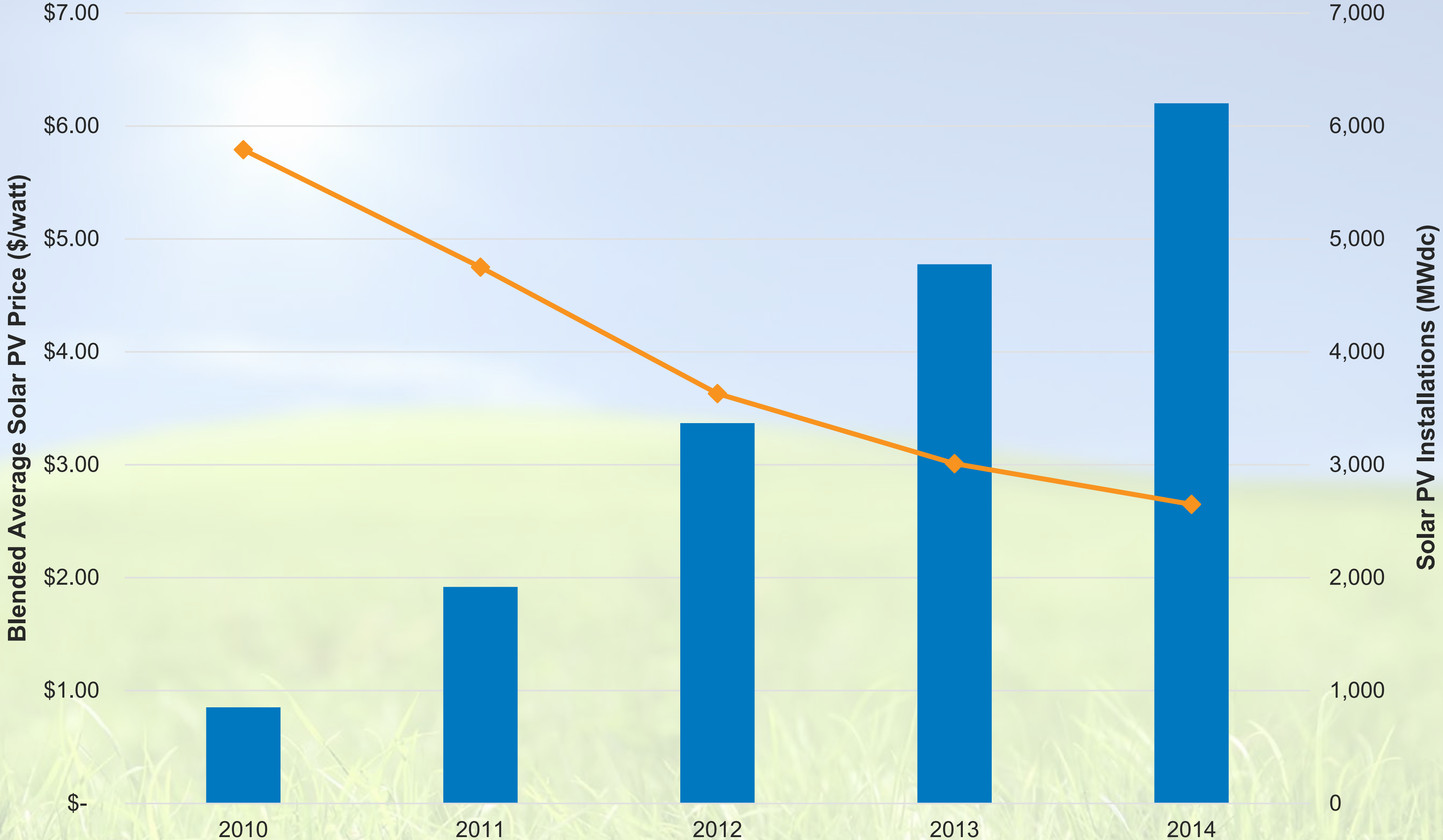
Solar as an Economic Engine

- Nearly 209,000 American workers in solar – more than double the number in 2010 – at more than 8,000 companies



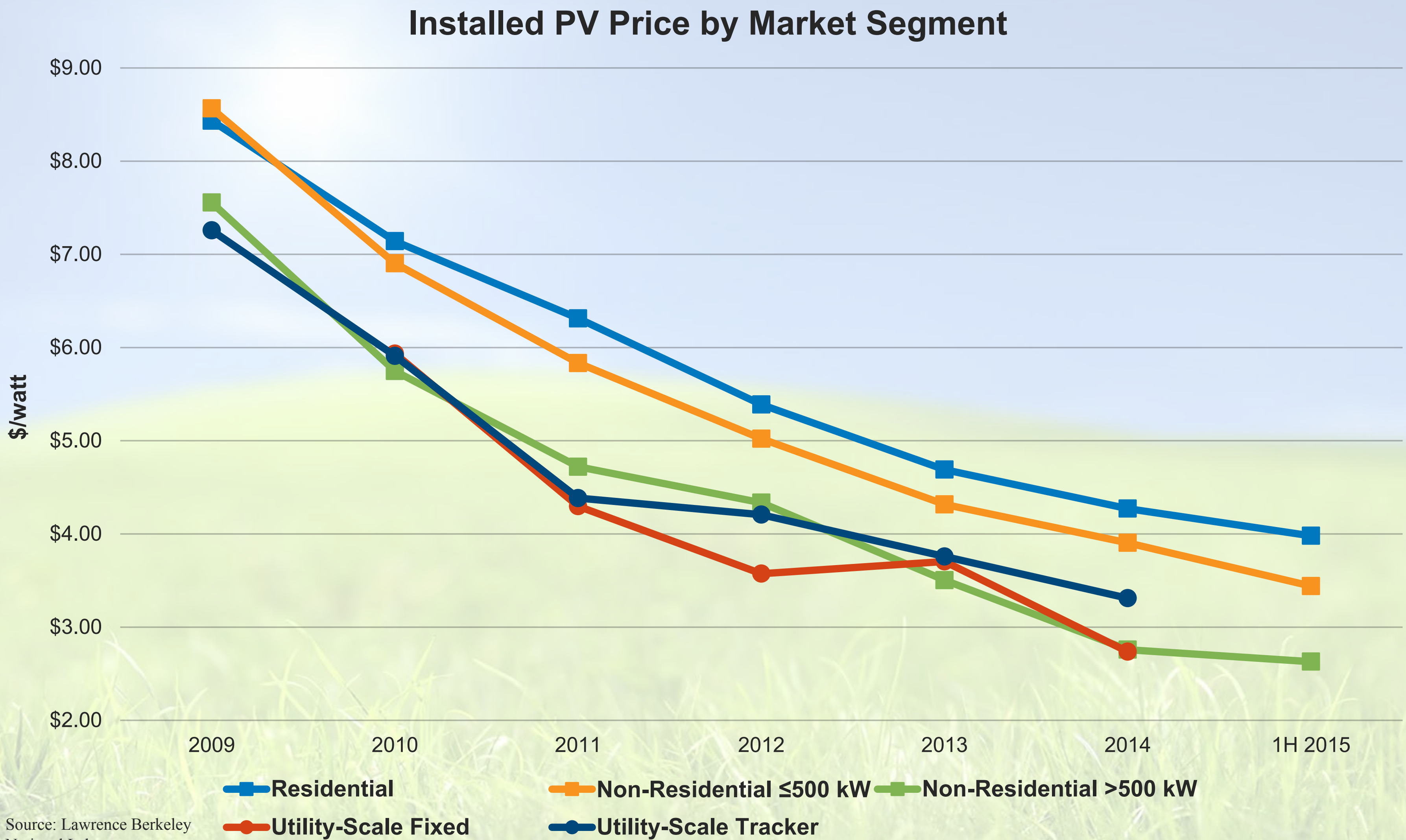
Source: The Solar Foundation *National Solar Jobs Census* and Bureau of Labor Statistics

Growth in Solar led by Falling Prices



Source: SEIA/GTM Research *U.S. Solar Market Insight Q4 2014*
greentechmedia.com/research/ussmi
Lawrence Berkeley National Laboratory, *Tracking the Sun*

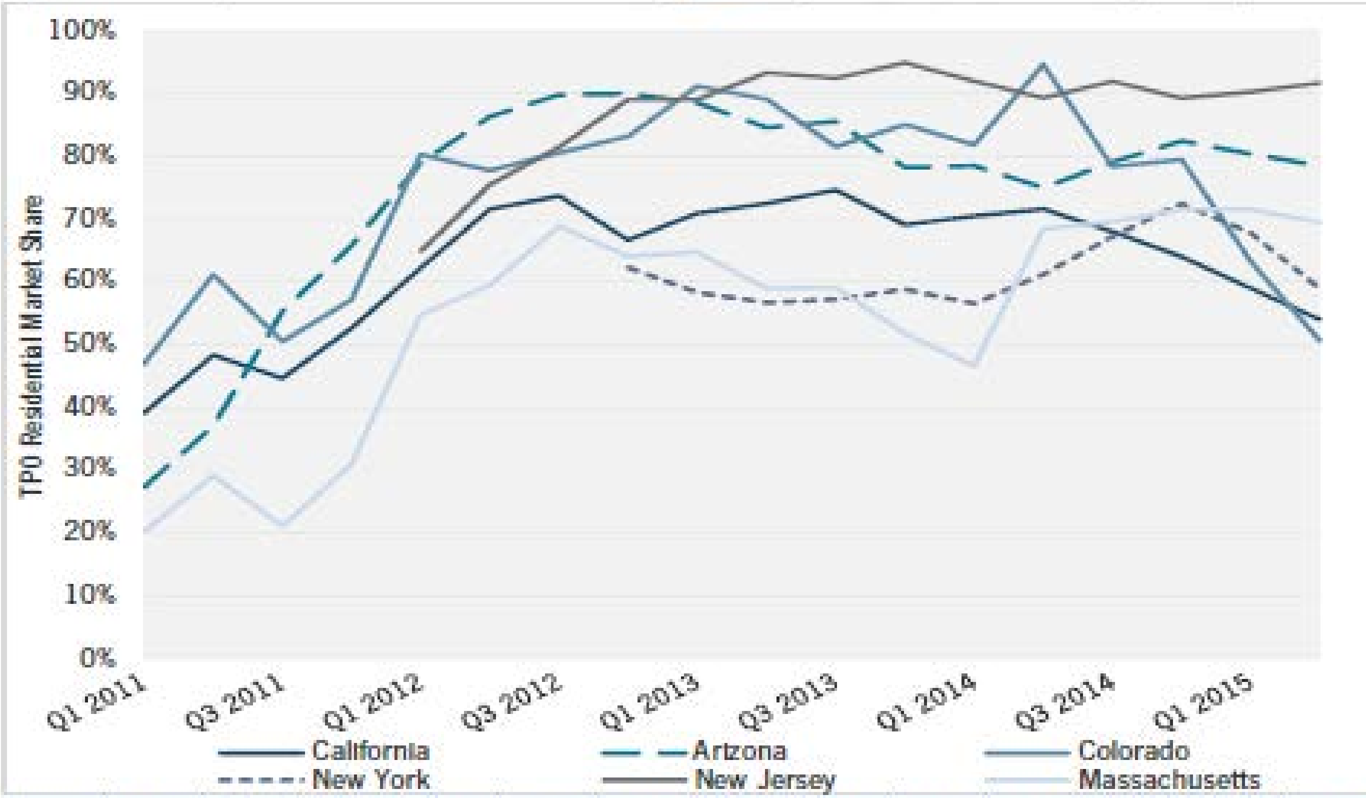
PV Prices fall by 50%+ over last 5 years



Source: Lawrence Berkeley National Laboratory

Residential Third-Party Ownership Broadens Access to Solar

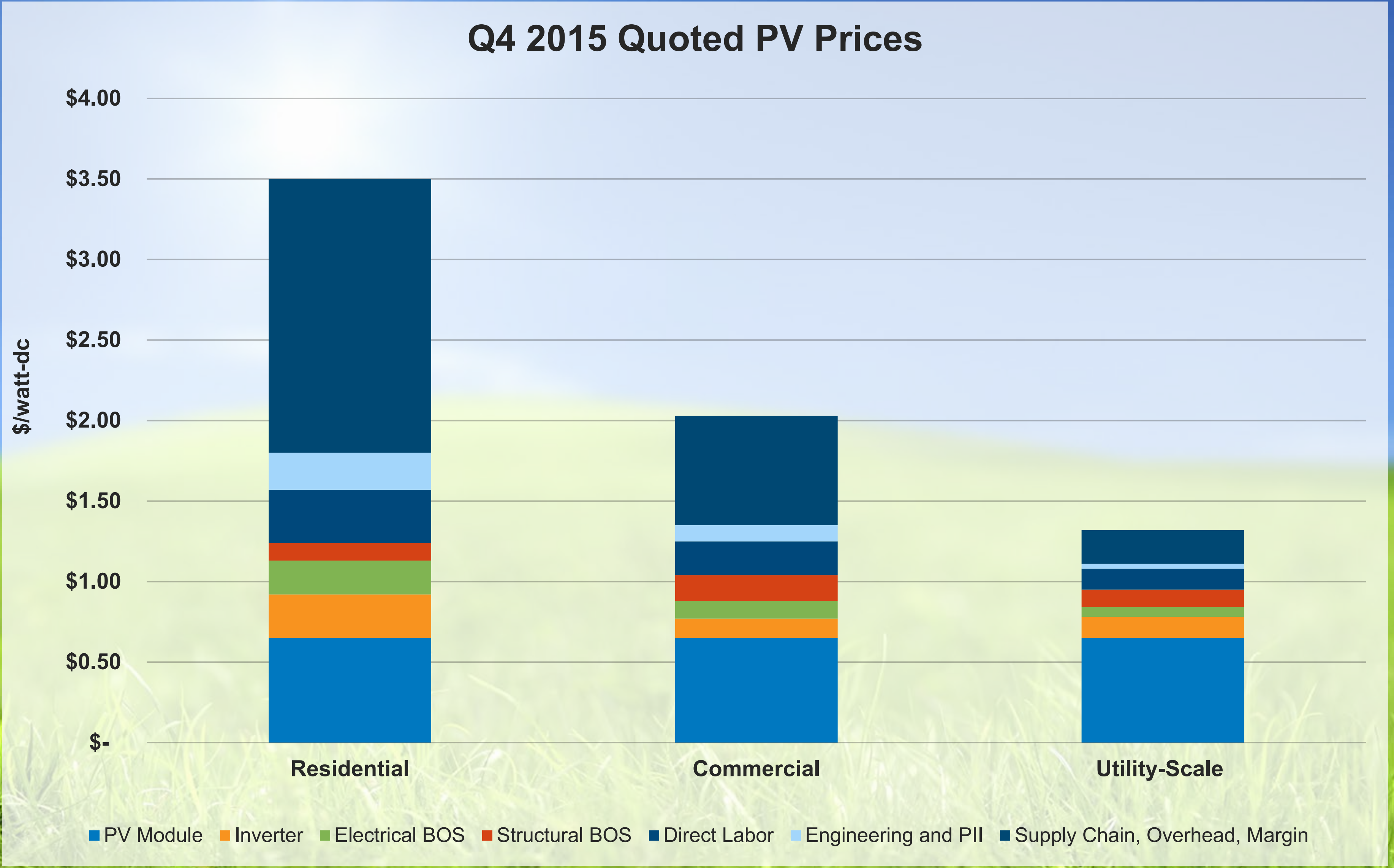
Figure 2.4 Percentage of New Residential Installations Owned by a Third Party in CA, AZ, CO, NY, NJ and MA, Q1 2011-Q2 2015



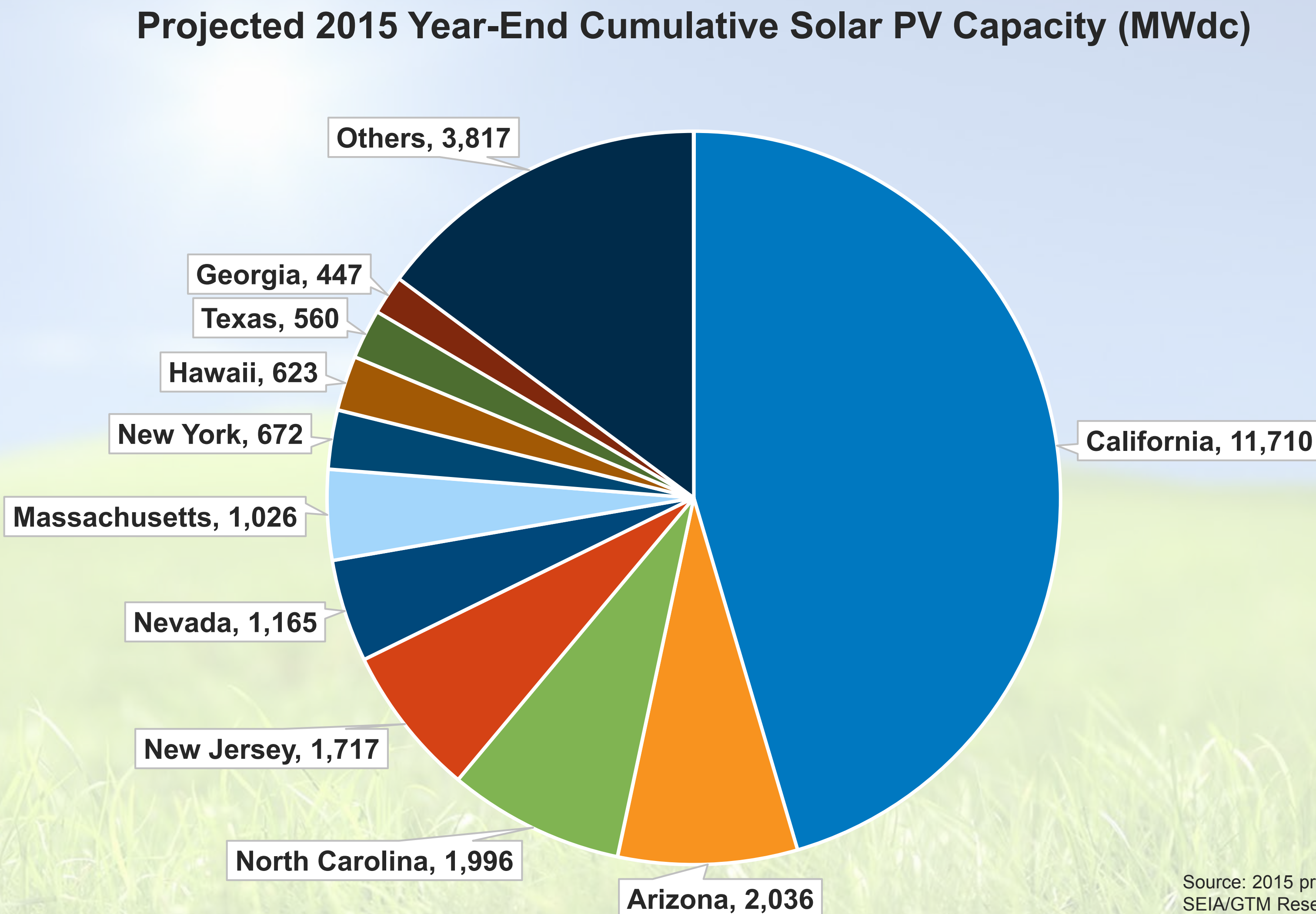
	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014	Q3 2014	Q4 2014	Q1 2015	Q2 2015
CA	72%	74%	67%	71%	73%	75%	69%	71%	72%	68%	64%	59%	54%
AZ	86%	90%	90%	89%	85%	86%	78%	78%	75%	79%	82%	80%	78%
CO	78%	81%	83%	91%	89%	82%	85%	82%	95%	78%	79%	63%	51%
MA	59%	69%	64%	65%	59%	59%	52%	47%	68%	70%	72%	72%	69%
NJ	75%	81%	89%	89%	93%	92%	95%	92%	89%	92%	89%	90%	92%
NY			62%	58%	57%	57%	59%	57%	61%	67%	72%	68%	59%

Source: SEIA/GTM *U.S. Solar Market Insight Q2 2015*

Solar PV Price Breakdown



U.S is a 50 state market



Source: 2015 projections from SEIA/GTM Research *U.S. Solar Market Insight*

Moving Beyond Traditional Solar Markets: Distributed Generation (21)

Top 10 DG States by Absolute Growth

	State	2011-15 DG MW	2016-2020 DG MW	DG Growth
1	California	3,880	13,234	9,353
2	New York	510	2,711	2,201
3	Massachusetts	937	2,256	1,319
4	Maryland	306	1,111	805
5	Connecticut	185	912	727
6	New Jersey	1,132	1,683	551
7	Texas	113	598	486
8	Florida	106	574	468
9	Minnesota	28	472	444

Top 10 DG States by % Growth

	State	2011-15 DG MW	2016-2020 DG MW	DG % Growth
1	South Carolina	8	172	2097%
2	Minnesota	28	472	1579%
3	Indiana	9	130	1348%
4	Virginia	19	208	1003%
5	Michigan	15	151	936%
6	New Hampshire	23	222	868%
7	District of Columbia	15	136	796%
8	Delaware	32	271	752%
9	Illinois	22	180	731%
10	Vermont	55	399	632%

1	Vermont	87.11	637.61	550.50
2	Delaware	33.56	285.99	252.42
3	California	99.12	338.07	238.94
4	Connecticut	51.58	253.90	202.32
5	Massachusetts	137.84	331.97	194.13
6	District of Columbia	22.63	202.86	180.22
7	Hawaii	322.62	484.18	161.56
8	New Hampshire	17.25	166.94	149.70
9	New Mexico	33.63	179.78	146.14
10	Maryland	50.92	184.91	133.99

Source: SEIA/GTM Research

Moving Beyond Traditional Solar Markets: Utility-Scale (21)

Top 10 Utility-Scale States by Absolute Growth				
	State	2011-15 Utility-Scale MW	2016-2020 Utility-Scale MW	Utility-Scale Growth
1	Texas	394	4,233	3,840
2	California	7,179	10,407	3,229
3	Utah	194	1,466	1,272
4	Nevada	777	1,978	1,201
5	Florida	21	1,173	1,152
6	Georgia	339	1,392	1,054
7	New Mexico	250	1,287	1,037
8	Oregon	26	1,042	1,016
9	Colorado	162	956	794
10	Virginia	2	750	748

Top 10 Utility-Scale States by % Growth				
	State	2011-15 Utility-Scale MW	2016-2020 Utility-Scale MW	Utility-Scale % Growth
1	Washington	0.0	142.4	-
2	Iowa	0.0	68.0	-
3	Louisiana	0.0	33.7	-
4	New Hampshire	0.0	12.5	-
5	Virginia	2.1	750.4	36414%
6	Minnesota	2.3	682.6	29578%
7	Michigan	1.3	333.5	26372%
8	South Carolina	3.7	525.2	14095%
9	Florida	20.9	1,173.0	5511%
10	Oregon	26.3	1,041.8	3861%

Top 10 Utility-Scale States by Per Capita Growth				
	State	2011-15 watts/person	2016-2020 watts/person	Growth in watts/person
1	New Mexico	119.99	617.30	497.30
2	Utah	64.80	489.22	424.42
3	Nevada	268.73	684.25	415.52
4	Hawaii	38.23	333.57	295.34
5	Oregon	6.53	258.58	252.06
6	Vermont	94.04	286.45	192.42
7	Colorado	29.63	175.15	145.51
8	Texas	14.33	154.11	139.78
9	Minnesota	0.42	124.34	123.93
10	South Carolina	0.76	107.27	106.52

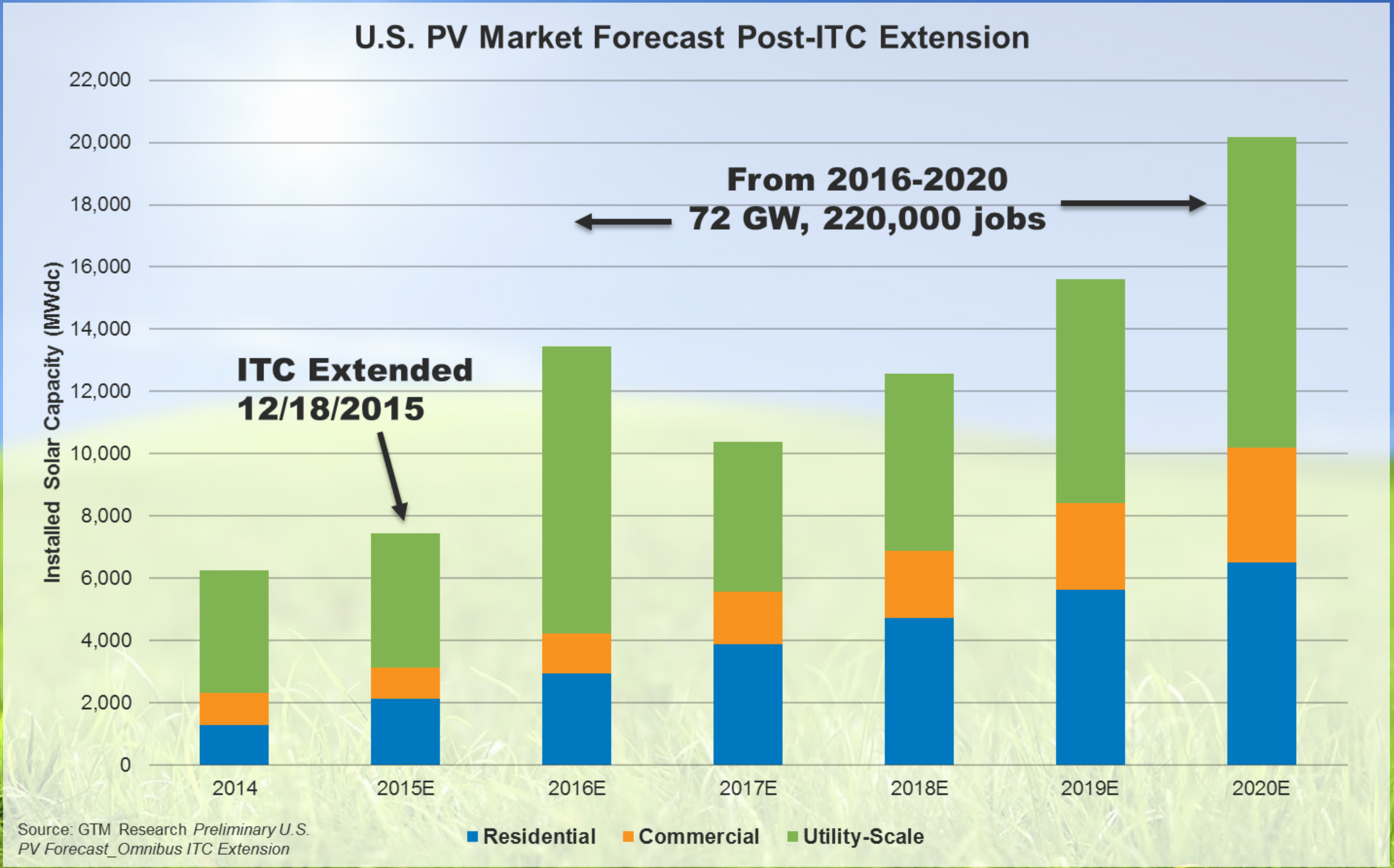
Source: SEIA/GTM Research

SEIA Solar Energy Industries Association®

Extending the ITC

- Extended at 30% through the end of 2019
  - Drops to 26% in 2020 and 22% in 2021
  - After 2021, Commercial credit drops to 10%, Residential credit expires
- Commence Construction language added
  - Projects must be placed in service before the end of 2023

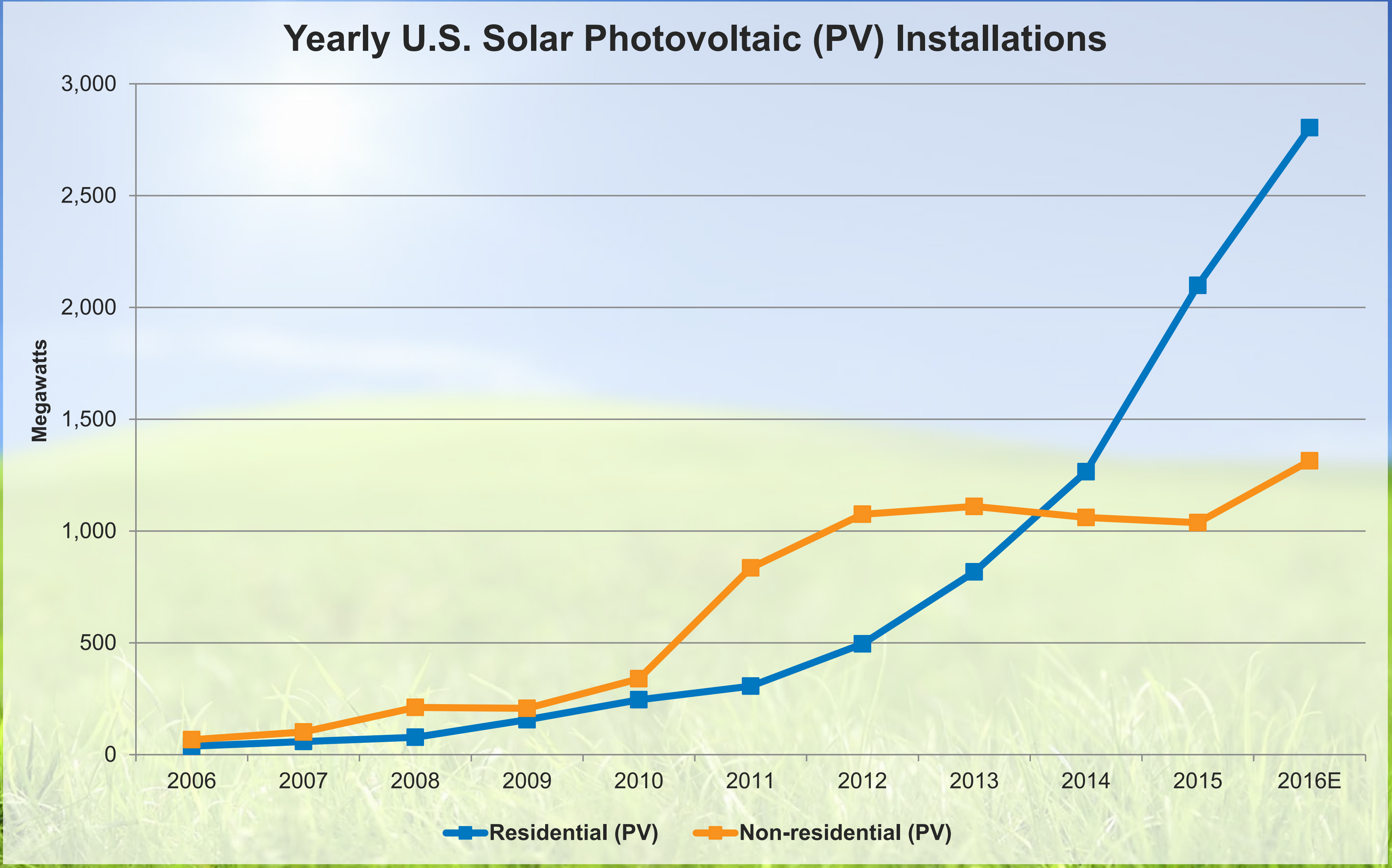
100 GW by 2020 with Extension



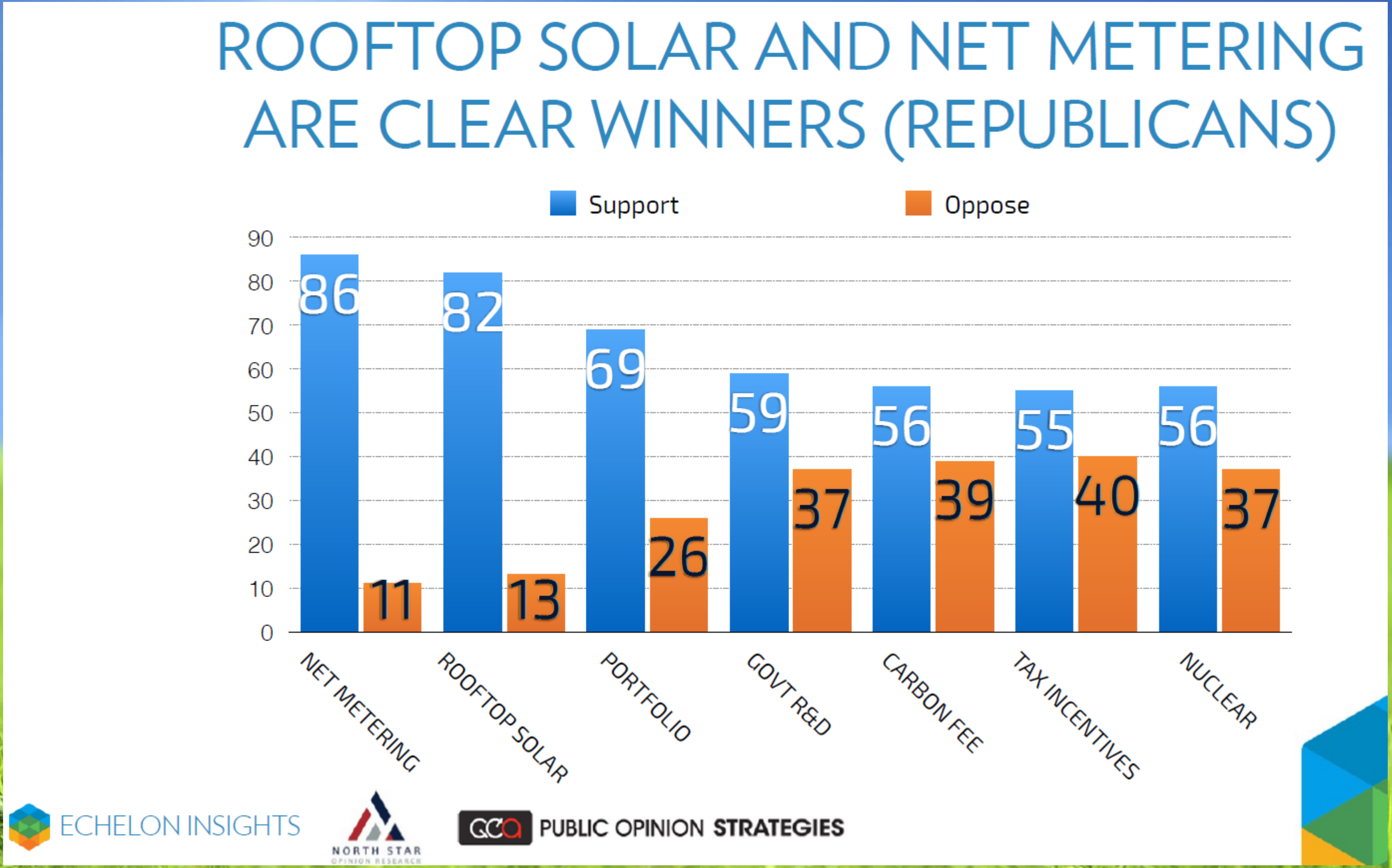
2016 SEIA State Policy Priorities

- **Priority states**:
  - CA, CO, NV, NY, MA, NJ, TX, Southeast (GA, FL, NC), Midwest
- **What does SEIA do in these states?**
  - We work in state legislatures and state regulatory agencies, promoting policies that make the states safe for solar
- **Policies? Like what?**
  - Clean Power Plan: ensure that states incorporate solar in their plans to comply with the CPP
  - Renewable Portfolio Standards (RPS): require utilities to deliver a certain amount of power from renewable generation (wind, solar, geothermal)
  - Community Solar: Extend opportunities to go solar to apartment dwellers, customers who with shaded roofs, poor credit, etc.
  - Net Metering: require utilities to allow rooftop solar customers to sell surplus solar production back to the grid (generally at retail rates)
  - Third Party Ownership: Legalize solar leases and PPAs for residential and small commercial customers
  - Tax policy: state tax credits (similar to the federal ITC), tax abatements, property tax exemptions, etc
  - Consumer Protection: Tools for customers and rules for industry to ensure customers have adequate information and are treated fairly

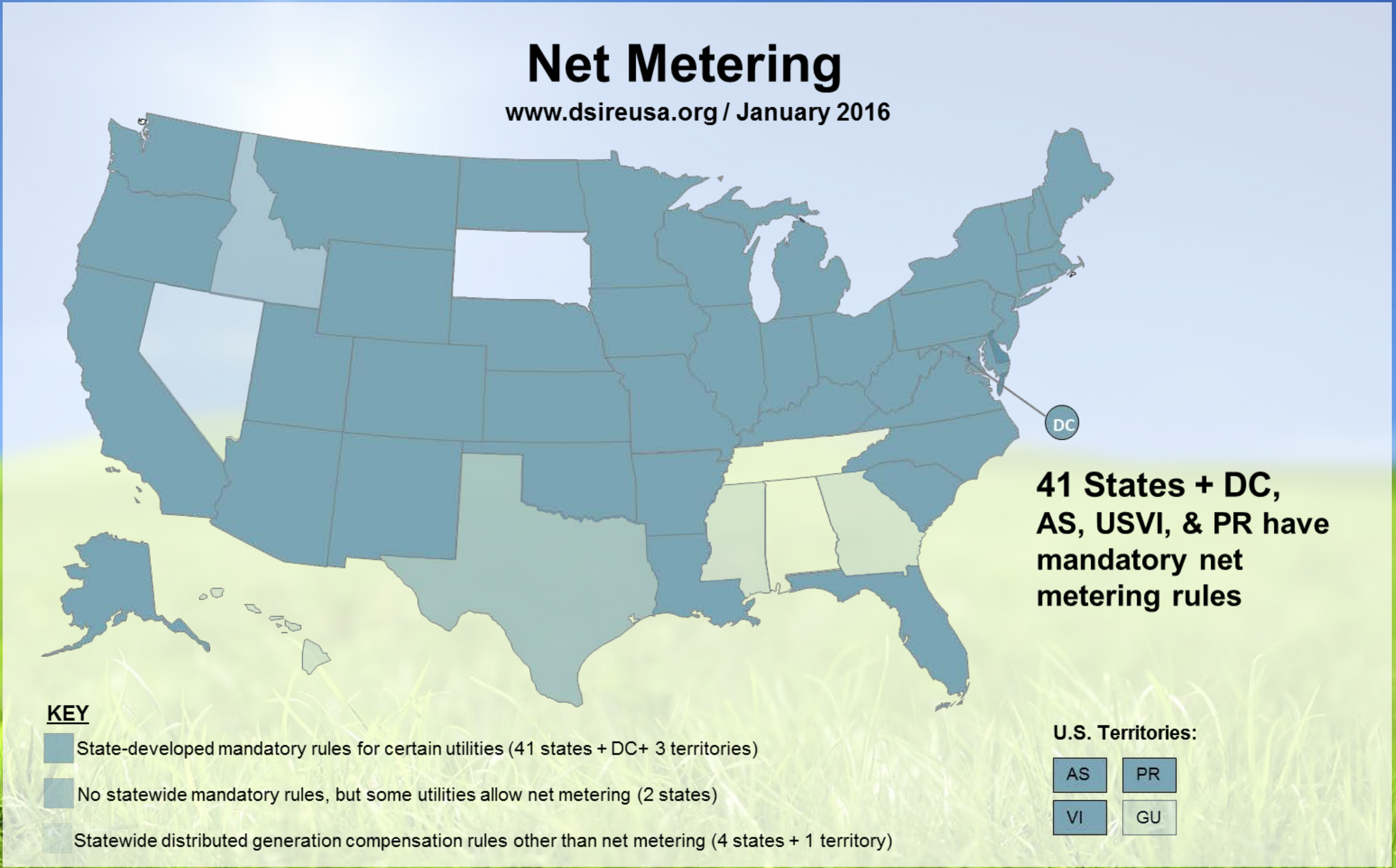
Residential & Commercial (Distributed)



Broad Public Support for Solar

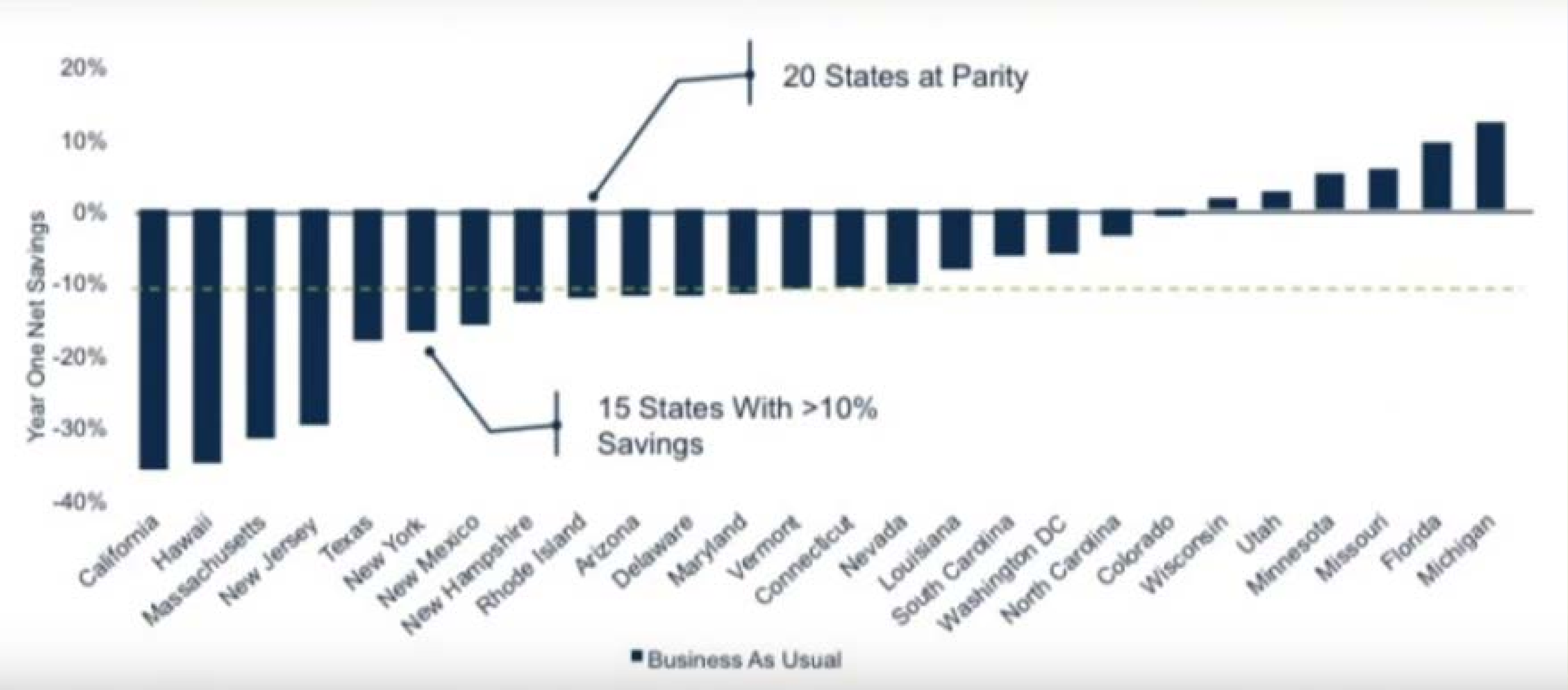


Net Metering



Net Metering

- **Under current NEM rules, distributed generation solar at grid parity in 20 states**



Source: Shayle Kann, GTM Research
U.S. Solar Market Insight Conference
Keynote: *The Future of Solar*

Figure 4. Proposed or Enacted Changes to Net Metering Policies in 2015

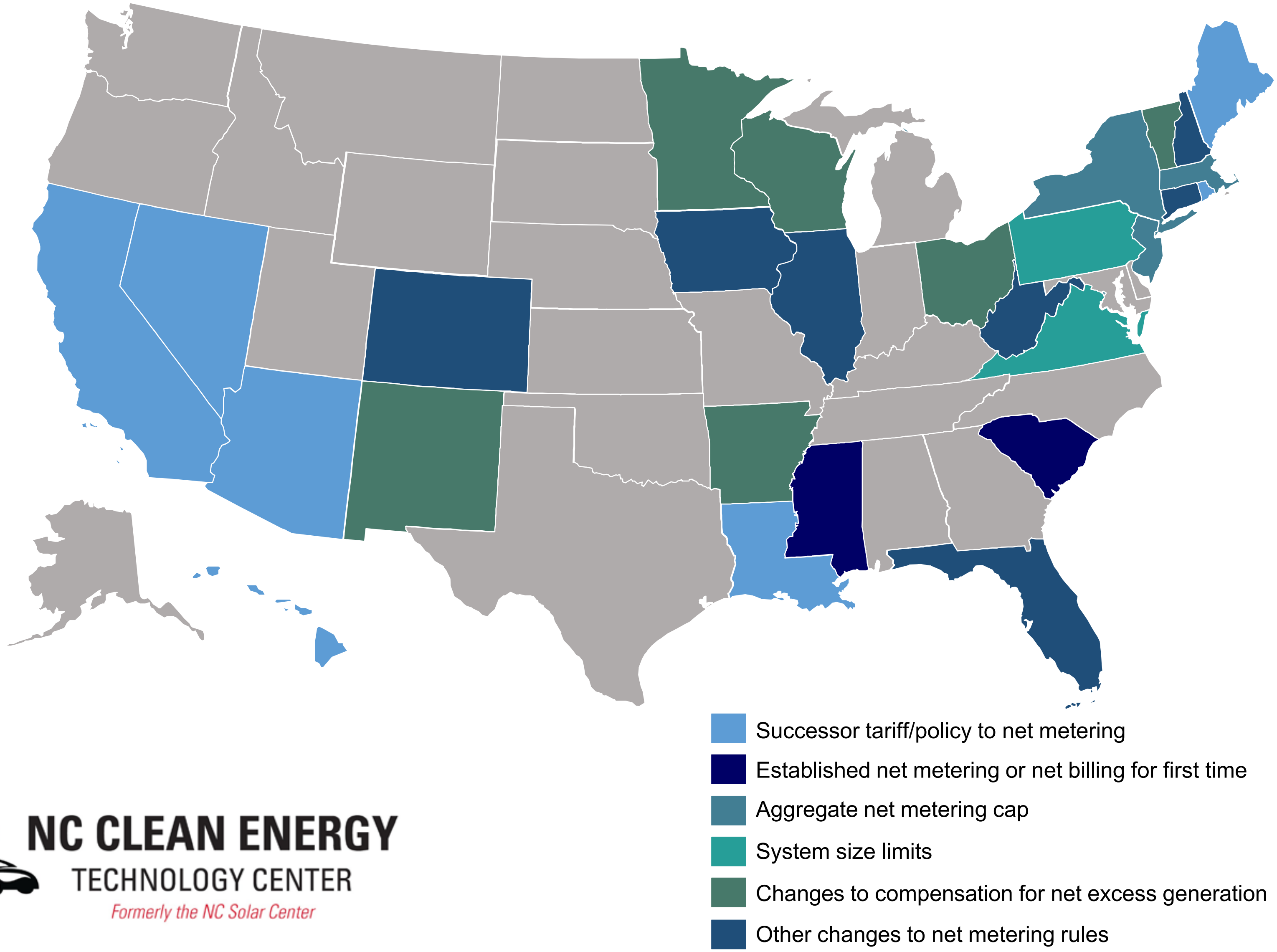
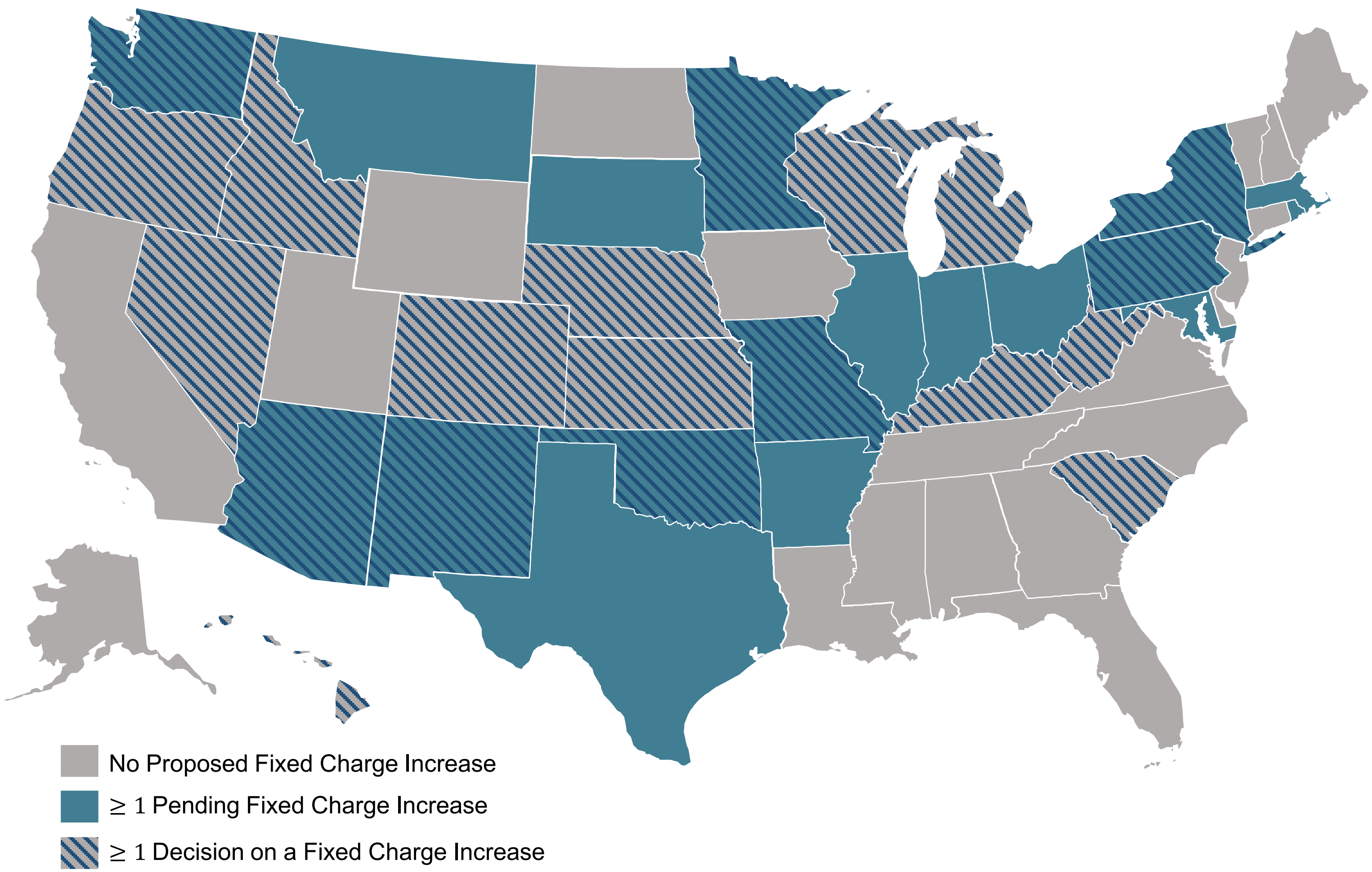


Figure 10. Pending and Decided Utility Residential Fixed Charge Increases in 2015



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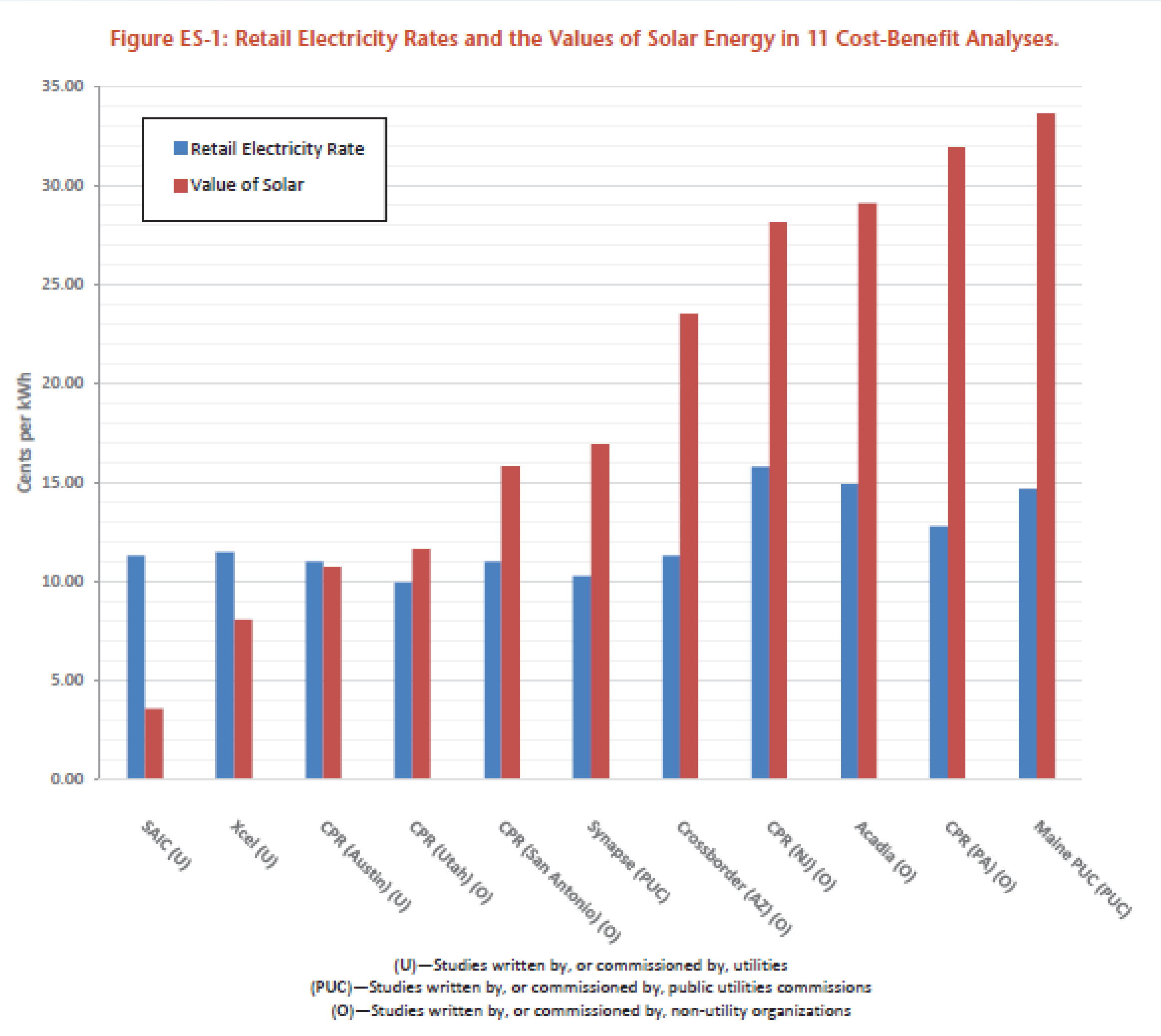
NEM Cost Benefit studies – Environment America 2015

- Environment America evaluated 11 studies completed between 2012 and 2015
- Eight of 11 studies found that the value of solar energy was worth more than the average residential retail electricity rate in the area at the time the analysis was conducted.
- The three analyses that found different results were all commissioned by utilities



Source: Environment America, “Shining Rewards, The Value of Rooftop Solar Power for Consumers and Society”, Summer 2015

DG Costs & Benefits

Annual Net Benefits of 2017-2019 NEM Rooftop Solar Deployments

Type	Benefit and Cost Category	Net Benefits (Excl. Environmental)	Net Benefits + Environmental
		2015 Levelized cents/kWh	
Benefits	Energy	3.7	Same
	Line Losses	0.4	Same
	Generation Capacity	2.6	Same
	Ancillary Services	0.1	Same
	Transmission & Distribution Capacity	2.8	Same
	CO_2 Regulatory Price	0.9	Same
	Voltage Support	0.9	Same
	Criteria Pollutants	Not included	0.1*
	Environmental Externalities	Not included	1.7*
	Total Benefits	**11.4**	**13.2**
Costs	Program Costs	0.1	Same
	Integration Costs	0.2	Same
	Participant Bill Savings	9.5	Same
	Total Costs	**9.8**	**9.8**
	Total Net Benefits	**1.6 cents/kWh**	**3.4 cents/kWh**

*More recent academic studies estimate the criteria pollutants cost to be up to 5 cents/kWh[22] and the social cost of carbon to be as high as 12 cents/kWh in Nevada.[23]

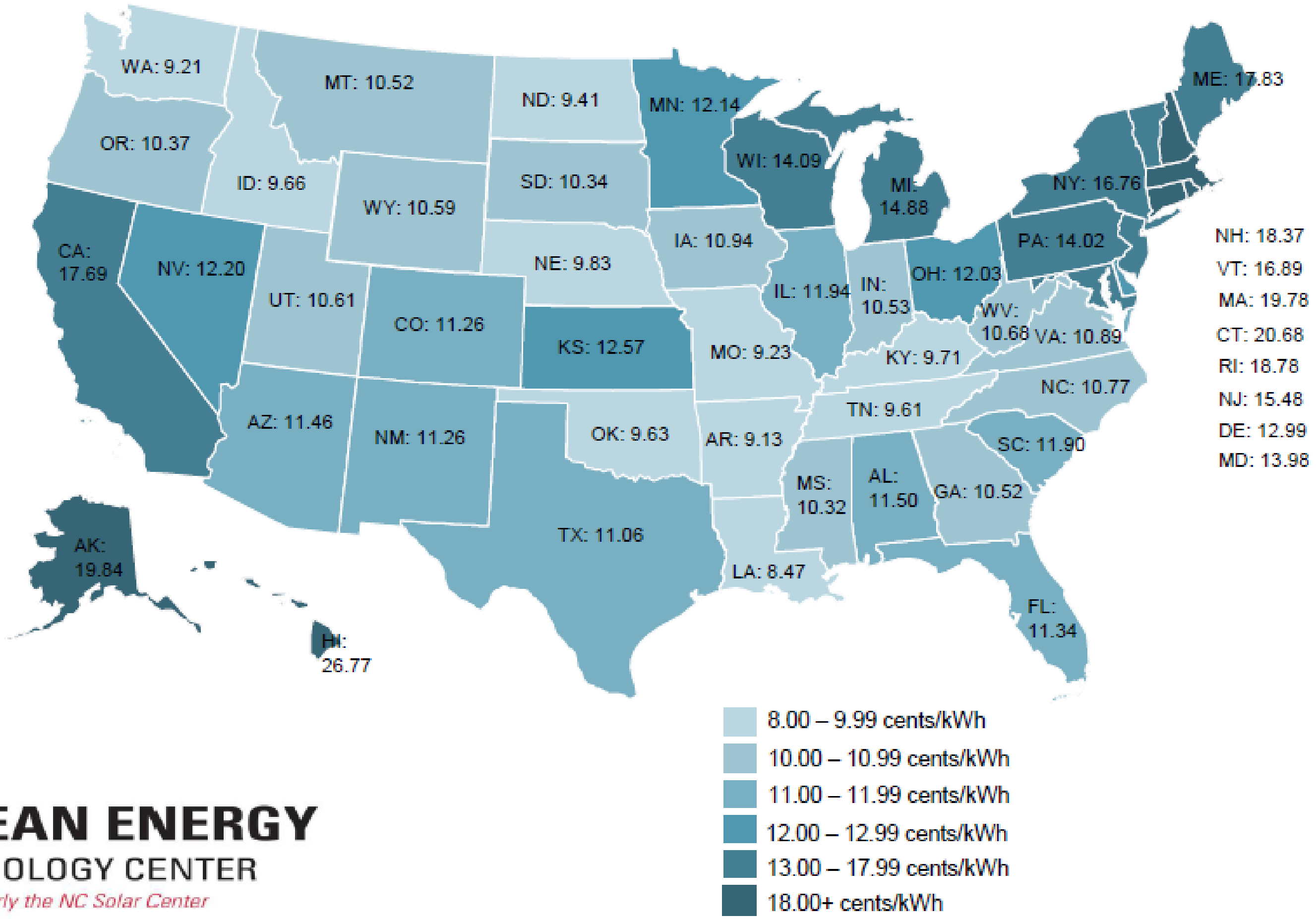
Source: Solar City & NRDC, Distributed Energy Resources in Nevada, May 2016

Average Retail Rates

NC STATE UNIVERSITY

Average Residential Electricity Rate by State (cents/kWh; Feb. 2016)

Source: U.S. Energy Information Administration



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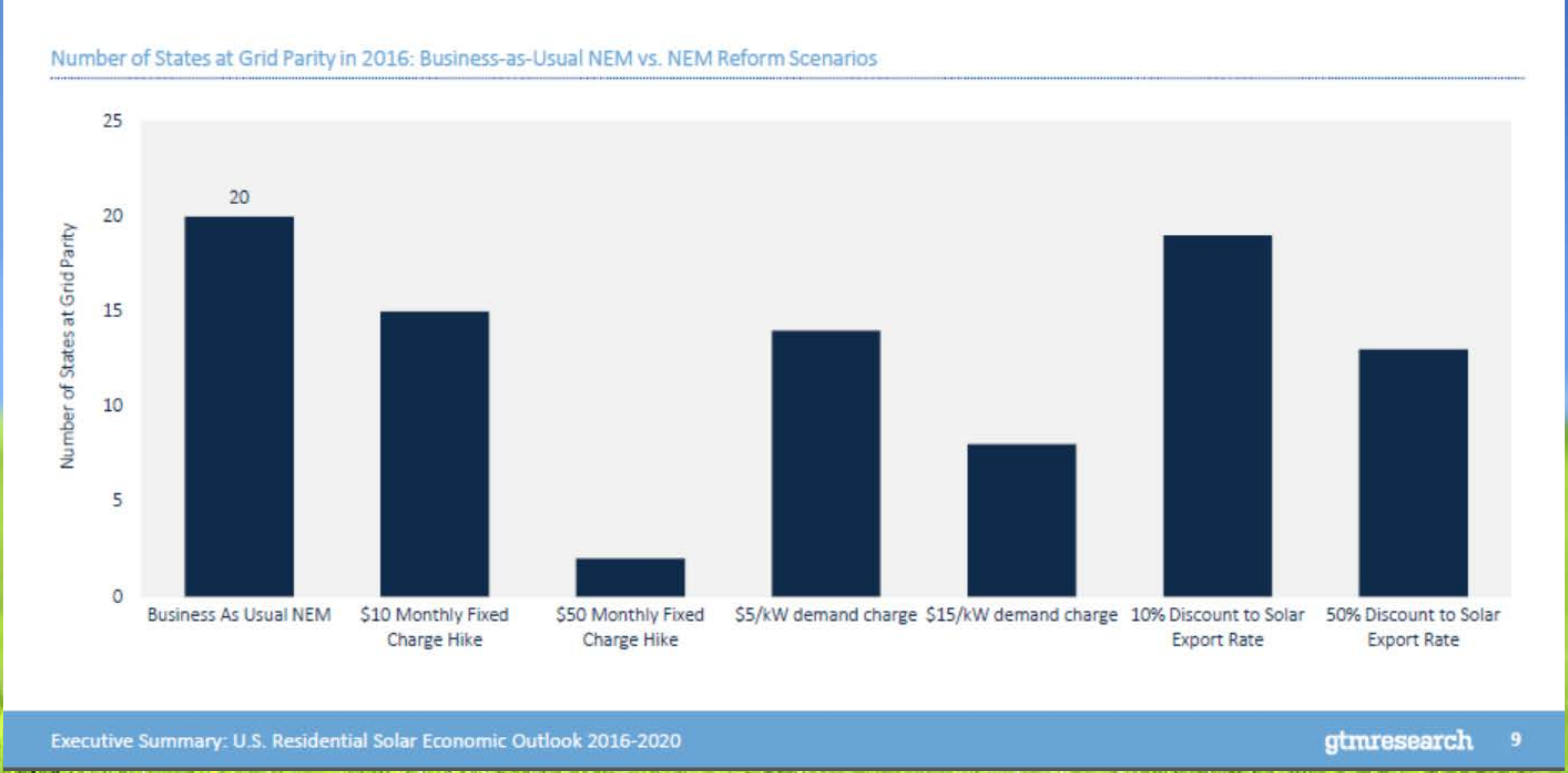
Net Metering

- **If export rate is cut in half, 0 states at grid parity**
- **Nevada outcome looms large, but not emblematic of NEM policy nationally**

Source: Shayle Kann, GTM Research *U.S. Solar Market Insight* Conference Keynote: *The Future of Solar*

Impact of other rate design changes



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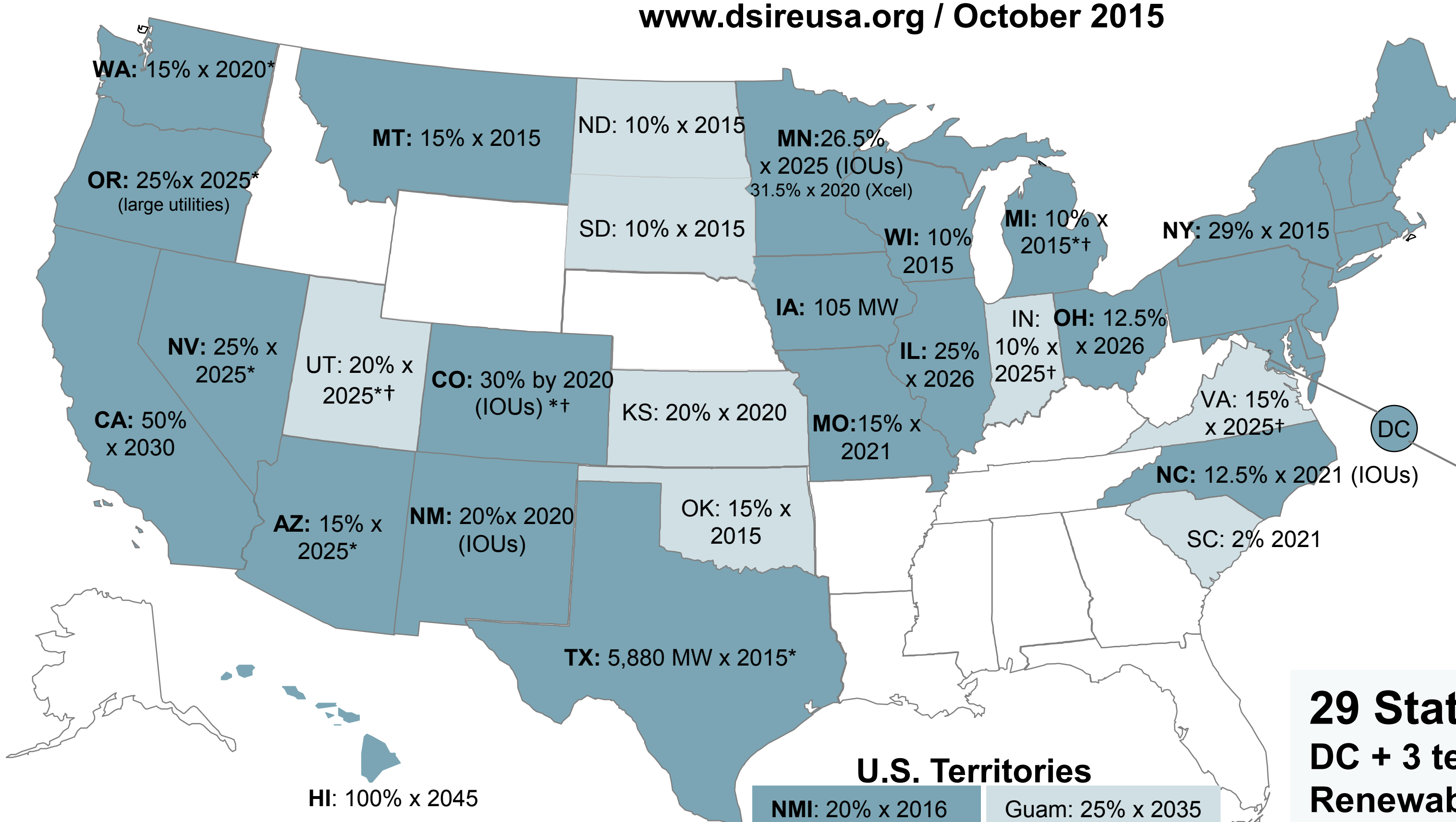
Renewable Portfolio Standard Policies

www.dsireusa.org / October 2015



ME: 40% x 2017
NH: 24.8 x 2025
VT: 75% x 2032
MA: 15% x 2020(new resources) 6.03% x 2016 (existing resources)
RI: 14.5% x 2019
CT: 27% x 2020
NJ: 20.38% RE x 2020 + 4.1% solar by 2027
PA: 18% x 2021†
DE: 25% x 2026*
MD: 20% x 2022
DC: 20% x 2020

U.S. Territories

NMI: 20% x 2016	Guam: 25% x 2035
PR: 20% x 2035	**USVI**: 30% x 2025

29 States + Washington DC + 3 territories have a Renewable Portfolio Standard

(8 states and 1 territories have renewable portfolio goals)

- Renewable portfolio standard
- Renewable portfolio goal

* Extra credit for solar or customer-sited renewables

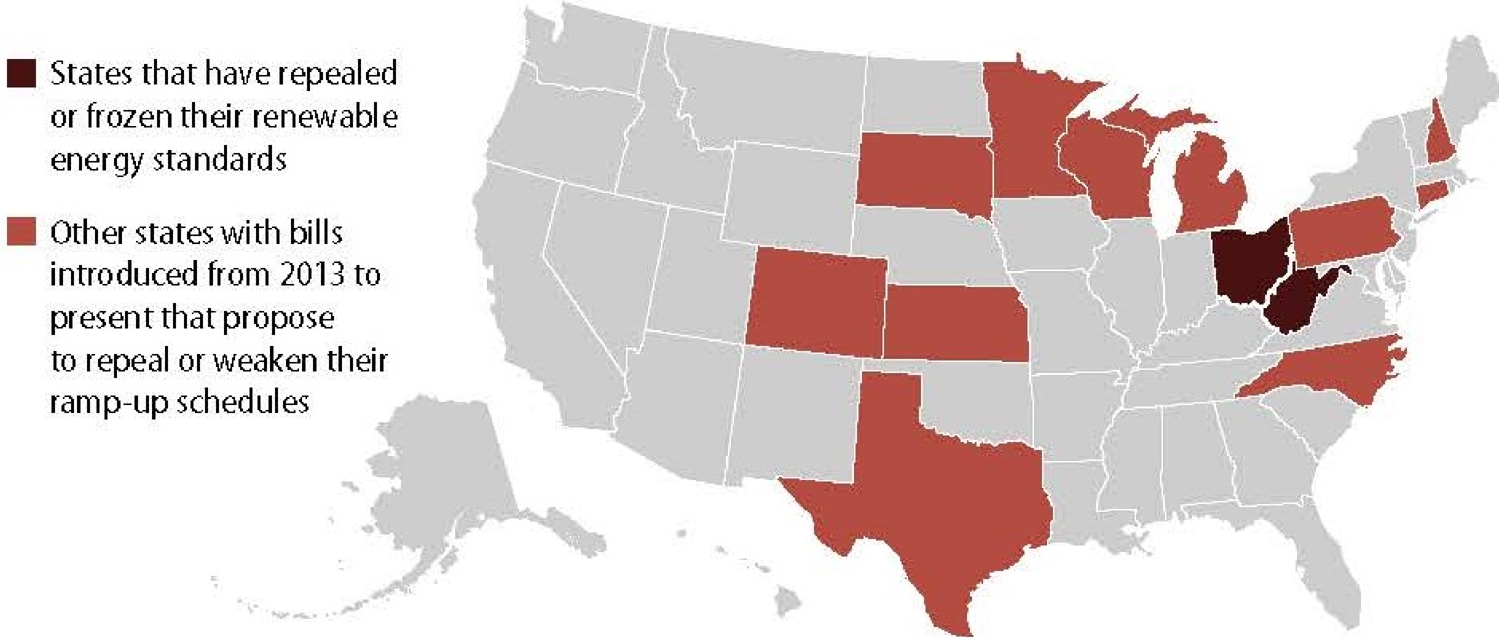
† Includes non-renewable alternative resources

State RPS – threats since 2013

FIGURE 1

Battles over state-level renewable energy standards

Selected efforts to repeal or weaken ramp-up schedules for renewable energy



- 13 states have considered repeal or weakening RPS (Source: Center for American Progress report, March 2015)
- Ohio RPS frozen; WV RPS repealed (but included clean coal and old tires)
- Colorado and NC bills to weaken RPS defeated in 2015
- Texas bill to weaken RPS passed state Senate in April, but died in House
- Kansas bill to make RPS voluntary agreed to by AWEA May 2015

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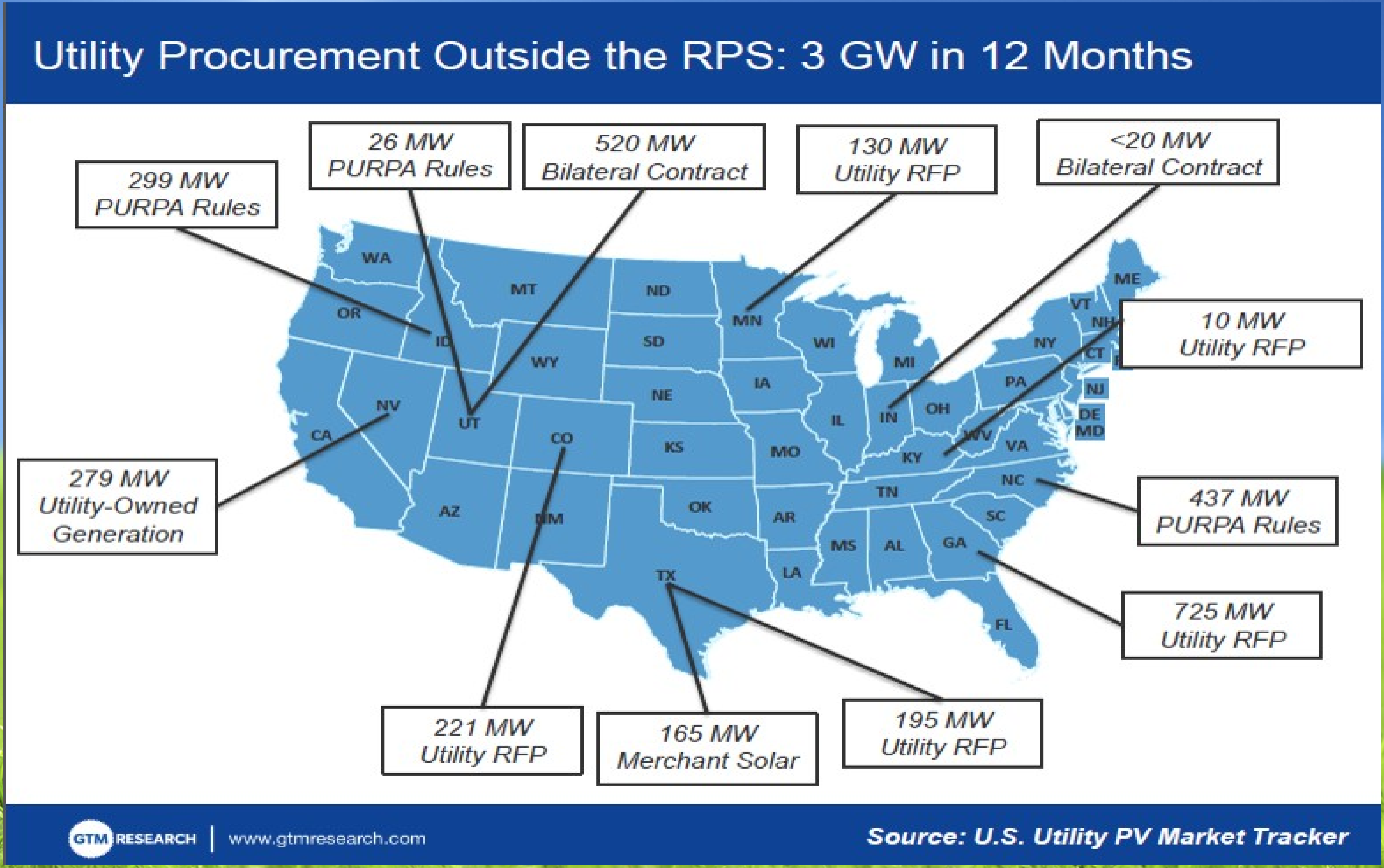
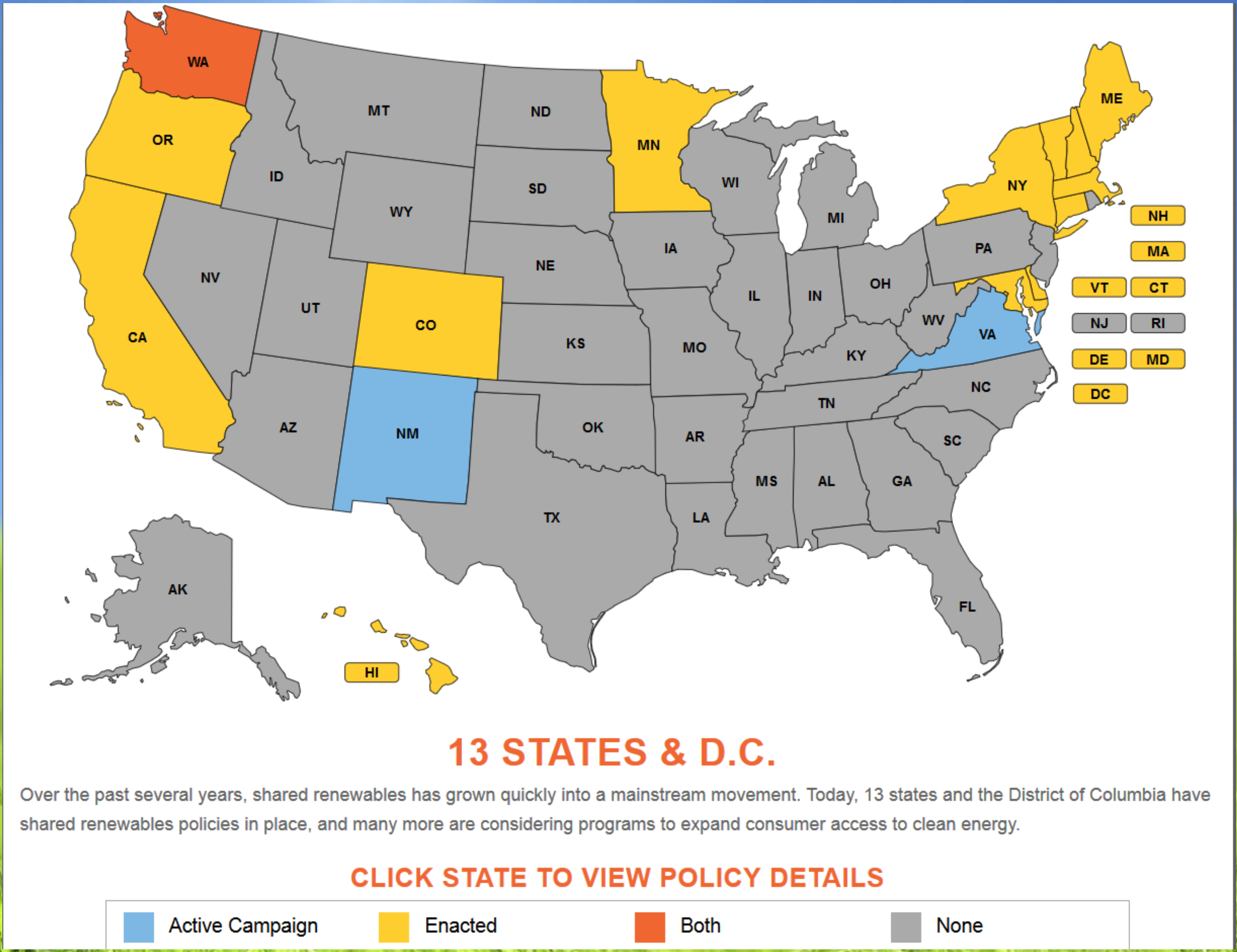
Industry Trends: Non-RPS Procurement



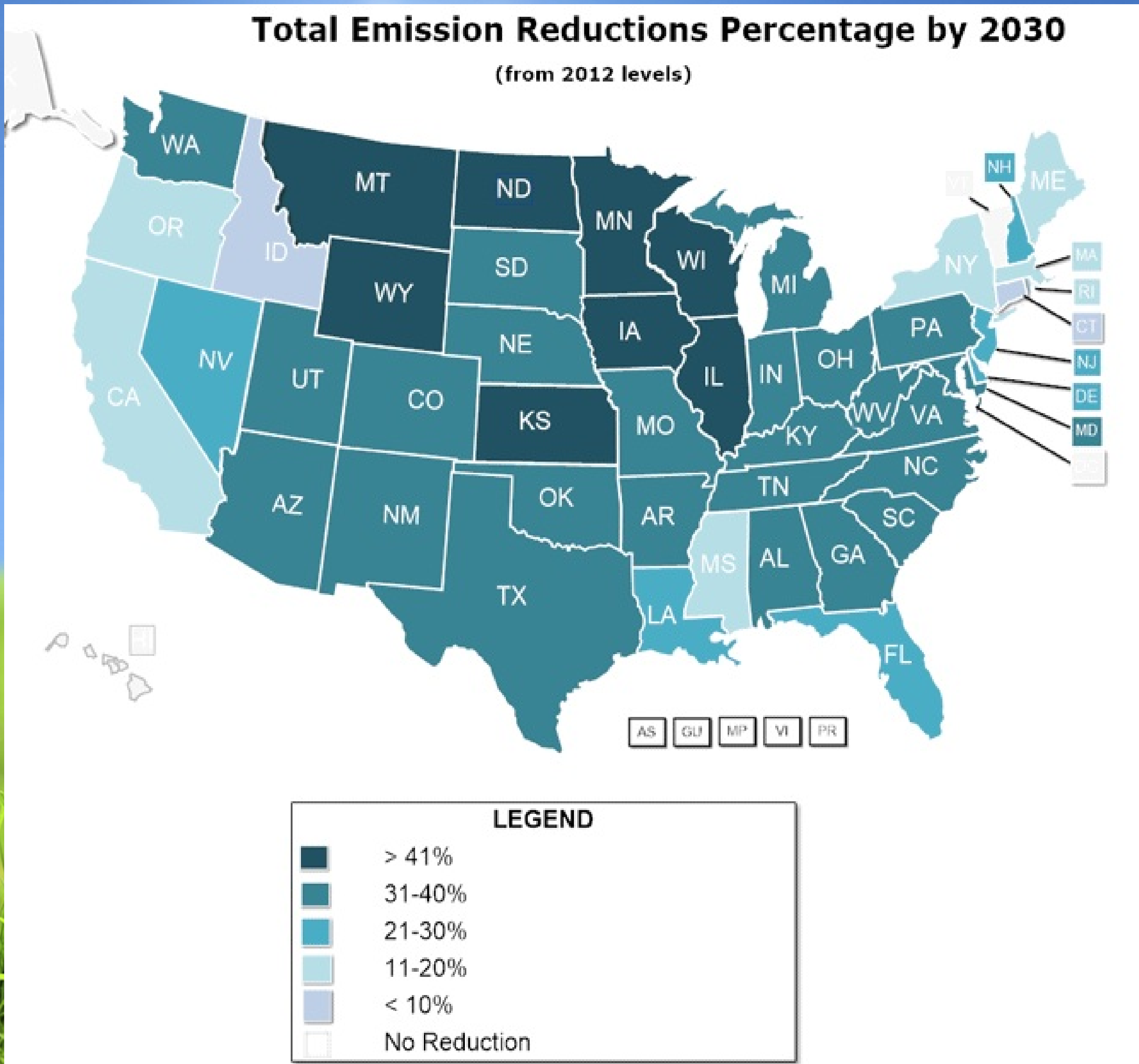
Industry Trends: Community Solar



- 13 states & DC have adopted shared or community solar programs
- Expands solar access to more customers
  - Multi-family
  - Shaded roof
  - Low & moderate income
  - Poor credit
- Multiple business models, including utility ownership

Source: http://www.sharedrenewables.org/community-energy-projects/

Clean Power Plan - Opportunity



- CPP will drive 20 GW of additional capacity by 2030
- SEIA is focused on Southeast & Midwest
  - State targets > 35%
  - States planning SIPs
  - Open new markets
  - Cross over with other SEIA policy priorities
  - Regional approach allows efficient use of resources
- CPP Mechanisms could include:
  - RPS expansions (CA, IL, MI)
  - IRP (GA, CO)
  - Other utility RFP (TN, VA)
  - Utility ownership (AL)
  - Community Solar (MN, CO)

40 YEARS SEIA Solar Energy Industries Association®

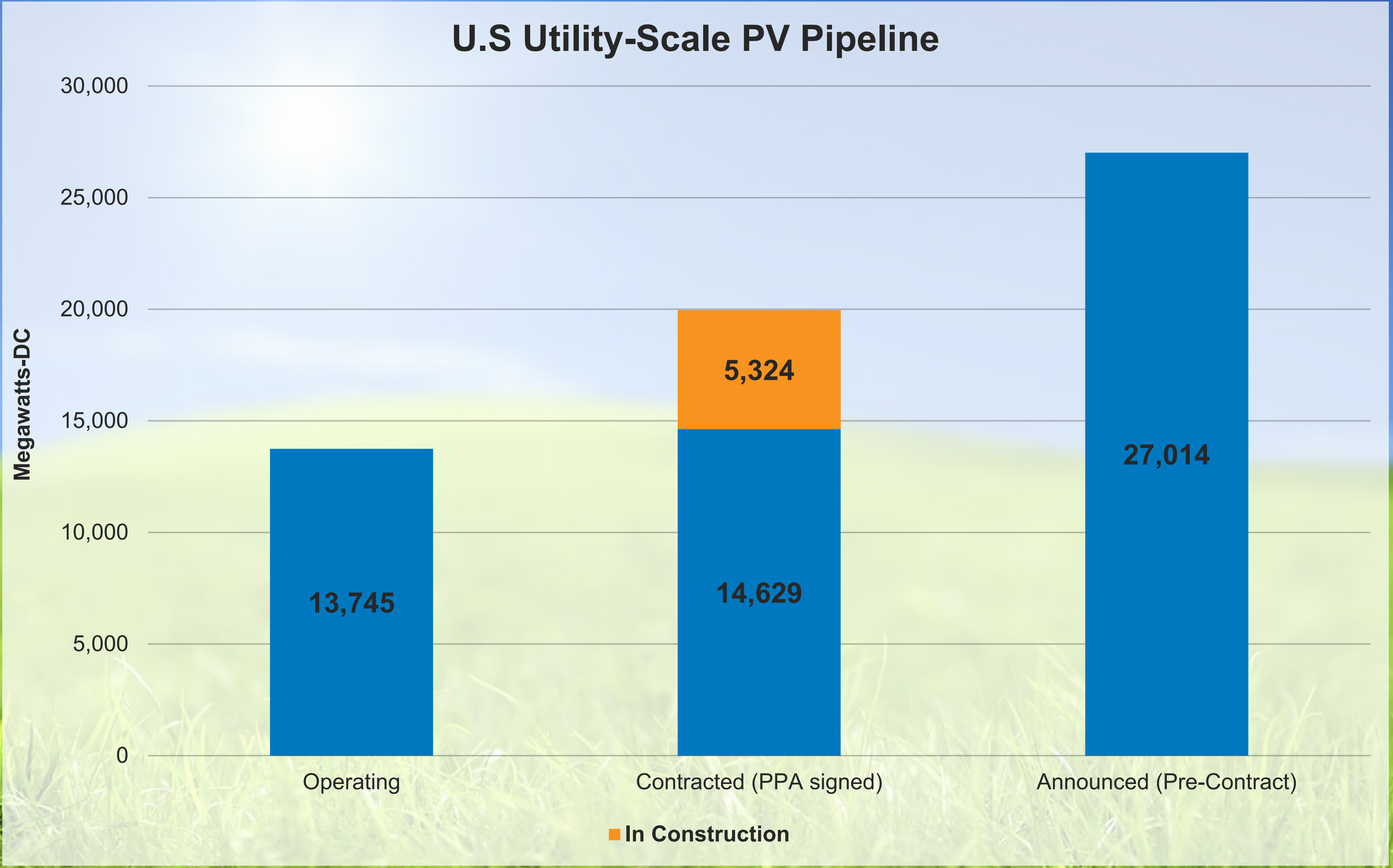
Changing Policy Landscape – Utility Scale Solar

- Not just RPS any more – though RPS remains big driver
- USP gains acceptance from Utilities as prices fall and utility holding companies gain experience owning & operating large solar plants
  - PPA pricing reported below $40/MWh
  - Utilities owning solar projects include:
    - Southern, Dominion, Mid-American, Duke
- Clean Power Plan and other economic and regulatory challenges to the aging coal fleet presents near term opportunities in the South.
- PURPA & voluntary markets
  - PURPA in NC
  - Voluntary programs by municipal utilities in Texas
  - Alabama (500 MW)
  - Virginia (400 MW)
  - Tennessee (800 – 3,800 MW)
  - Arkansas (~100 MW)
  - South Carolina (~100 MW)
  - Georgia Power IRP
- In slightly longer term Texas comes into play in a big way
  - ERCOT projects 13,000 MW solar

Changing Policy Landscape – Utility Scale Solar

- Corporate buyers present new market in some states
  - Kaiser virtual PPA in CA
  - Apple and Google projects in NC, VA
  - Switch in NV
  - Utilities in mature markets increasingly look to offload procurement obligations to other entities (e.g. PG&E, "even with 50% RPS, expect minimal procurement")
- Grid Integration and Transmission present challenges that will increase with penetration
  - Reduced capacity values with increasing solar penetration
  - California "duck curve"
  - Long distance transmission projects remain subject to multiple layers of state, federal and local regulation, with no end in sight
  - Grid-scale storage development remains nascent

Utility Scale



Industry Trends: Solar Plus Storage

- SEIA views storage as an enabling technology, for both the utility-scale and distributed generation markets
  - Storage and related advanced electronics enable solar projects to provide grid services to utilities, mitigates integration of variable resources, increases value to grid
- Solar-plus-storage deployments totaled 4 MWdc in 2014, but GTM Research expects them to grow to 22 MWdc in 2015 and reach 769 MWdc by 2020.
- California is expected to be the biggest solar-plus-storage market, with 422 MWdc installed in 2020 alone.
- In dollar terms, GTM expects the market to grow to $246 million in 2015 and $643 million in 2016. By 2020, the annual U.S. solar-plus-storage market will be $3.1 billion.
- State storage incentive programs/proceedings
  - California 1,300 MW by 2024
  - NJ FY 2016 incentive program
  - MA considering incentives for storage

Thank You