Deployment of Solar Photovoltaic Generation Capacity in the United States

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Executive Summary

This study describes the deployment of solar photovoltaic (PV) electricity generating capacity in the United States and provides a first-order explanation of the patterns described. It relies on the secondary literature, particularly for the earliest phases of deployment and for non-U.S. information. For the more recent period, it draws on national data from the *BP Statistical Review of World Energy* and state and segment level data assembled by the Interstate Renewable Energy Council (IREC), Greentech Media (GTM), and the Solar Energy Industries Association (SEIA).

The earliest U.S. deployment of PV occurred in cost-insensitive niches, first in space and then in terrestrial off-grid applications, during the 1960s and 1970s. Public policies that combined supply-push and demand-pull mechanisms, such as Federal RD&D spending and Federal procurement of PV systems, drove this process, which established that PV was a technologically viable means of generating power and prompted the building of the first module factories. After 1980, these policies were abandoned, and the pace of deployment in the U.S. consequently slowed considerably over the next two decades. However, deployment surged in other countries, first in Japan in the 1990s and then in Germany in the 2000s. Like the U.S., each of these countries combined supply-push and demand-pull policies to fuel their surges, although the specific mechanisms that they used differed.

In the 2000s, PV deployment in the U.S. accelerated; installed capacity grew approximately 60% per year during the decade. The acceleration was enabled by the adoption of supportive public policies for grid-connected PV, initially at the state level and later at the Federal level. It seems likely that, as in the 1970s, an unexpected rise in the price of oil triggered these policy changes. The price of PV systems had been declining due to the sustained growth of the global market, and these policies began to bring them within reach, especially for non-residential customers. Deployment was concentrated in a small number of states; California alone accounted for 60%. A combination of cash incentives, renewable portfolio standards, and solar carve-outs within these standards established by these states "heavily influenced" the deployment pattern, according to a leading study.[1] Federal tax incentives, first created in 2005, also added momentum to the deployment process during this decade. They particularly aided the non-residential segment, which already benefited from lower unit costs, by providing larger incentives and permitting the emergence of new leasing and ownership models.

PV deployment in the current, incomplete decade already dwarfs that of the 2000s. The continued rapid growth of the market, which averaged over 70% per year despite the much larger installed base, correlates with the resumption of cost declines after a pause in the late 2000s. The utility segment, enabled by low unit costs, spurred by ambitious state targets, and supported by Federal incentives beginning in 2008, superseded the non-residential segment and made up over half of the national total. Relying mainly on utility segment deployment and blessed by abundant solar resources, some southeastern states joined the leaders for the first time in this decade. Growth in other segments also reflected state policy priorities, such as the residential

[1] Andrea Sarzynski, Jeremy Larrieu, and Gireesh Shrimali, G., "The Impact of State Financial Incentives on Market Deployment of Solar Technology," *Energy Policy* 46:550-557 (2012), quote from p. 550.

segment in New York. California remained the bedrock of the national market, leading nearly every year across all segments. Growing familiarity with PV technology and improved financing options helped to sustain deployment growth as well, especially in the residential segment.

The tremendous growth of the PV market in the U.S. since 2000 may reasonably provoke the question of whether some leveling off might be anticipated soon. We believe that to be unlikely. The foundations for continuing to move up a steep diffusion curve, declining costs and generous Federal tax policy, seem secure for the short- and medium-term. California has shown a consistent commitment to expanding PV capacity and has creatively overcome a series of obstacles and challenges in the past decade and a half. While other states have not been as committed or creative as California, the number of states supporting PV deployment has tended to grow over time. State-level imitation and learning is likely to continue, with new pillars more than taking the place of those that crack. In particular, state policy-makers and utility executives seem likely to seize low- or no cost opportunities for utility segment growth in the Southeast and Southwest U.S., where PV with Federal subsidies alone is economically viable and some states have virtually no installed capacity yet. Over the long-term, it may be possible to extend the steeply sloped portion of the diffusion curve and delay reaching the inflection point through continued innovation in storage, utility business models, and other elements of this complex socio-technical system.

Key Takeaways

1. The deployment of solar PV has always been and continues to be dependent on public policy.
   - Federal RD&D investments and system purchases drove the earliest deployments.
   - The demise of these policies in the 1980s slowed deployment considerably.
   - Deployment accelerated in the 2000s when California and other states adopted policies that provided significant benefits for purchasers of PV systems, and Federal tax incentives first adopted in 2005 added momentum to this process.
   - The least expensive systems on a unit basis today, utility-scale systems in places with high insolation, continue to need Federal tax incentives to be competitive economically, although they may no longer need state policy support under the current Federal policy.

2. The evolving mix of public policies has shaped the deployment pattern across space, time, and market segment. Examples include:
   - California's sustained and creative adjustment of its policies, which have made it the dominant market across all segments in this century,
   - The expansion of eligibility for the Federal tax incentives to utilities in 2008, along with the enabling of third party ownership models, which catalyzed the explosive growth of the utility segment over the past decade, and
   - State policies favoring specific segments, such as the residential segment in Massachusetts and the utility segment in Georgia, have led these states to join the leading group of states in these segments.

3. It may be useful to think of the factors that explain the deployment pattern in the following way:
   - Unit costs are one foundation for decision-making by potential adopters and by policy-makers who must consider if and how to provide benefits that countervail these costs.
     - These costs have declined fairly steadily over time.
     - They vary systematically across segments; utility segment unit costs are lowest, and residential segment unit costs are highest.
   - Federal tax incentives have been a second foundation since 2005, a policy that has recently been extended through 2023.
     - This policy can in principle cut the cost across the entire country and all segments.
     - However, its impact in practice has depended on complementary state policies and on institutional innovation to take full advantage of the tax equity market.
   - State policies may be seen as pillars that build upon these foundations.
     - State policies are not easy to summarize, unfortunately; the best-known database that tracks them currently lists 38 categories of state policy.
     - The mix of state subsidies, tax breaks, interconnection and net metering regulations, portfolio standards, and other policies expand the benefits or cut the costs for particular groups of potential adopters, yielding distinctive market profiles at the state level.

4. Stable public policies enable innovations in institutions, understanding, and behavior that spur further deployment, but policy instability in any single location has not necessarily undermined deployment as long as policy-makers elsewhere provided support.
   - Stable Federal tax policy over the past decade, for example, has provided confidence to entrepreneurs who have built manufacturing and installation businesses, investors who have funded new capacity, and system owners and off-takers with sites for systems, all of whom have acquired assets that will provide returns over many years to come.
   - Similarly, although the specifics of California's solar policy have changed significantly over time, the stability of the state's commitment to expanding PV capacity have encouraged long-term investments by such stakeholders.
   - Policy instability has led to boom and bust cycles in particular places at particular times, such as in Japan in the 1990s and New Jersey in the 2000s, but in many such cases, other countries and states have picked up the baton in what can be seen as a global relay race.
     - These instances have not been coordinated, but the fact that there are a diversity of jurisdictions independently making policy decisions may in itself insulate the national and global market from boom and bust cycles to some extent.

Figures

1. Introduction: Is the Future Now?

Solar energy, especially distributed solar photovoltaic (PV) electricity generation, has intrigued metal-benders and tree-huggers alike for decades. The technology combines technical "sweetness" – a basic system has no moving parts -- with environmental "greenness" – it produces no emissions during operation. Except for a few niche applications, however, solar PV has not been commercially viable...until now, maybe.

"Grid parity," an elusive condition in which the unsubsidized, levelized cost of PV-generated power is the same as that of power from conventional sources, seems to have been achieved in some locations and times today. Assuming costs continue to decline, it will become more and more widespread tomorrow.[2] However, such assertions require caveats ("maybe," "seems," and "assuming," for instance, above), especially in their extreme form (such as predictions of a "solar revolution").[3] Competing technologies and resources are far from static, and relative costs will still depend on complex and unpredictable regulatory and investment decisions, even if all policies intended to shape the generation mix were magically removed.

We can say with confidence, though, that the cost gap between PV and other means of electricity generation has narrowed considerably over time. This narrowing has occurred in a positive feedback loop with deployment. Early deployment in cost-insensitive niches during the 1960s and early 1970s helped to establish the PV module production process, although public R&D support was more important in driving down costs in this phase. Deployment in more conventional applications accelerated after the oil crises of the 1970s, first in the U.S. and then abroad, when and where public policies combined supply-push and demand-pull mechanisms.

After decades of stagnation, PV deployment in the U.S. picked up again in the 2000s, with growth rates accelerating from 10-15% per year in the 1980s and 1990s to over 50% per year after the turn of the century. Rising oil prices once again triggered this process, but market formation policies, including subsidies, incentives, and mandates at both the Federal and state levels, contributed to technological, financial, and institutional innovations that sustained price declines and deployment growth. These innovations matured in the most recent phase of deployment, beginning in 2009, when utility-scale systems emerged for the first time to dominate the PV market.

This paper traces the history of PV deployment in the United States through these phases. As the data become more granular over time across states and market segments, we advance increasingly nuanced interpretations of the deployment pattern. Although our knowledge remains incomplete, there is no question that public policy in diverse forms and through diverse channels has been the dominant influence on PV deployment. Whether, when, and how that role can be handed off to the market is the overarching question looking forward.

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[2] Jason Channel, *et al., Energy Darwinism II: Why A Low Carbon Future Doesn't Have to Cost the Earth,* Citi, August 2015. GTM, *U.S. Solar Market Insight, 2015 Year in* Review, March, 2016 (GTM 2016a), a document upon which rely heavily in this paper, calculates grid parity by state, including policy subsidies (see table 27).

[3] Travis Bradford, *Solar Revolution* (MIT Press, 2006).

2. Measuring PV Deployment

This paper relies mainly on the secondary literature, particularly for the earliest phases of deployment and for non-U.S. information. The literature includes books, peer-reviewed articles, technical reports, dissertations, and working papers. For recent U.S. data, we draw on two sources of primary data.

The *BP Statistical Review of World Energy* provides annual data on cumulative installed PV capacity at the national level from 1996 to 2014.[4] This long-running publication seeks to provide high-quality, globally consistent data and is a widely-used reference source in the field. BP assembles its dataset from international and national public and private sources. This series is the longest consistent one available.

We also use a data series initiated by the Interstate Renewable Energy Council (IREC) and continued after 2010 by Greentech Media (GTM) in collaboration with the Solar Energy Industries Association (SEIA).[5] National data from this source with a breakdown by off-grid and grid-connected are available in graphical form from 1998 to 2008. National level numerical data are available only for grid-connected capacity starting in 2001. The correlation between the BP and IREC/GTM/SEIA data varies over time. There are relatively large inconsistencies in the two series before 2005, perhaps because of differences in data collection methods, such as how off-grid capacity is treated.[6] From 2006 to 2009, the annual differences are smaller, negligible in 2007 and 2009, 2% in 2006, and 4% in 2008. After 2009, they are well under 1% each year. These differences suggest refraining from drawing conclusions about these early years that depend on precise measurement.

The IREC/GTM/SEIA provide important breakdowns by state and market segment. Market segment data are also available in graphical form on a national basis from 2000 and in numerical form from 2010.[7] Numerical data by state start in 2006, and breakdowns by both state and market segment, in 2010.

IREC/GTM/SEIA define market segments according to who receives the power generated by a PV system, with "non-residential" serving as a residual category. "The spectrum of non-residential off-takers typically includes commercial, industrial, agricultural, school, government and nonprofit customers....a "community solar" system is defined as non-residential as well."[8] As Bolinger and Seel (2015) point out, segments may also be defined by system size or total cost, which would presumably yield somewhat different breakdowns. Federal and state programs use a variety of categories that sometimes align imperfectly with these data.[9]

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[4] "Renewable Energy - Solar (Installed capacity)" (worksheet) in *BP Statistical Review of World Energy Workbook*, June 2015, available at http://www.bp.com/statisticalreview .

[5] GTM 2016a, *op. cit.*, p. 71 links IREC to GTM data. These data were used by DOE EERE, for instance, in its *2008 Solar Technology Markets Report*, January 2010, pp. 6-10 and *2014 Renewable Energy Databook*, p. 63.

[6] Neither dataset is accompanied by a precise data collection methodology.

[7] Some numerical data are also found in the text of annual IREC reports.

[8] GTM 2016a, *op. cit.*, p 70. The terms "commercial," "commercial and industrial," and "non-residential" are sometimes used interchangeably in the literature. For this report "non-residential" will be used.

[9] Mark Bolinger and Joachim Seel, *Utility Scale Solar 2014*, Lawrence Berkeley National Laboratory, LBNL 1000917, September 2015, p. 3.

The unit of measurement for these series is generally grid-connected megawatts (DC) of installed PV generating capacity. Off-grid capacity dominates the earliest years for which IREC data are available (in graphical form only, see figure 1). (An older data set compiled by Paul Maycock, reprinted here as figure 2, provides more detail.) But by 2010, IREC no longer even collected data on off-grid capacity, which it estimated to be 5% or less of grid-connected capacity installed that year.[10] This shift in the market reflected demand-pull policies that incentivized grid connection, such as net metering, which allows PV system owners to offset the cost of power that they pull from the grid at certain times by providing excess power to the grid at other times.

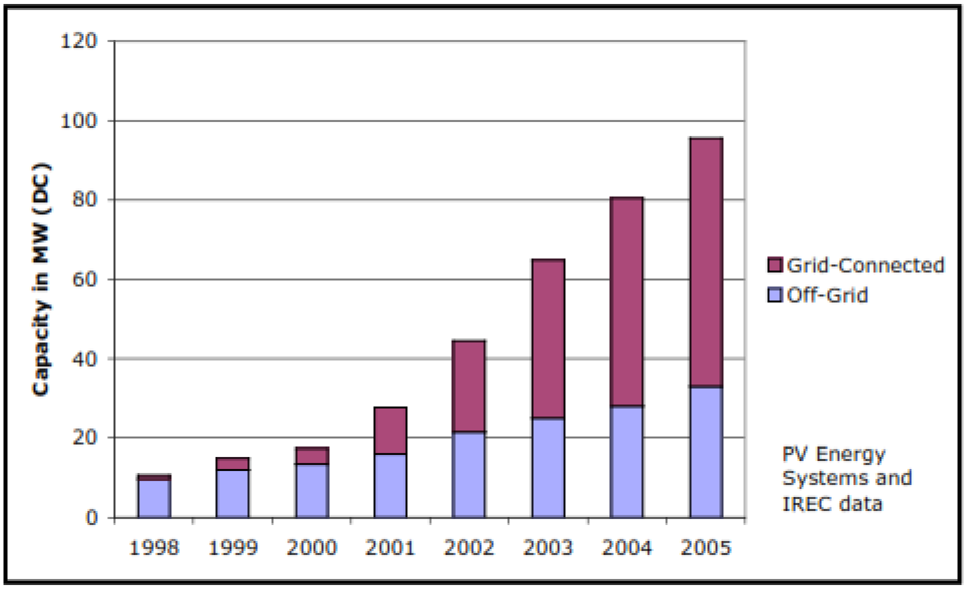

Figure 1: Annual Installed Photovoltaic Capacity (MW) in the U.S., 1998-2005[11]

[10] Larry Sherwood, "Solar Installation Trends," in IREC, "Updates and Trends 2010," (IREC, 2010), p. 23. It is possible that off-grid capacity may again become an important factor in the market if solar+storage systems gain traction.
[11] Larry Sherwood, "U.S. Solar Market Trends, 1998-2005," Interstate Renewable Energy Council and Sherwood Associates, 2006.

Applications by Market Sector (U.S.)

APPLICATION	19	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Grid-connected Distributed	2	2	2.2	3.7	5.5	12	22	32	57	65	101
Off-grid Consumer	4	4.2	4.5	5.5	6	7	8.4	9	10	12	14
Government Projects	1.2	1.5	1.5	2.5	2.5	1	1	1	1	1	2
Off-grid Industrial/ Commercial	4.4	4.8	5.2	6.5	7.5	9	13	16	18	21	23
Consumer (<40 W)*	2.2	2.2	2.4	2.4	2.5	3	4	4	4	4	4
Central Station	-	-	-	-	-	-	-	5	4	5	5
Total Installed in USA	*13.8*	*14.7*	*15.8*	*20.6*	*24*	*32*	*48.4*	*67*	*94*	*108*	149
Imports				2	4	5	9	18	40	55	65
Exports	25.1	36.3	37.9	39.8	55	73.3	81.2	54	88	100	118
Total Produced	38.9	51	53.7	60.8	75	100.3	120.6	103	138	154	202

Figure 2: PV Installation and Production (MW) in the U.S., 1996-2006[12]

An alternative approach to measurement would use electricity generated (MWh) by PV systems. This approach would capture operating experience, which depends on weather conditions, demand, the status of the generating system, and the status of the grid, among other things. However, the main concept that we seek to measure is technology deployment, which as we discuss below, is closely linked to upfront cost, which is, in turn, closely linked to production and installation experience. These concepts are better proxied by installed capacity than by electricity generated.

3. PV Deployment Before 2000

Installed PV capacity was mainly extraterrestrial before the 1970s, thanks to the very high value that space and defense agencies placed on having miniature, durable power sources for spacecraft and satellites. Terrestrial applications began to grow after the 1973 energy crisis, during what Staffan Jacobsson and his colleagues label "the era of unlimited solar optimism."[13] However, with the exception of a few niche markets, these applications were not viable without

[12] Paul Maycock, "2006-2015 World PV Market: Technology & Cost," PV Energy Systems, Inc., n.d., (http://www.ncsl.org/print/energy/PMaycockSolar1007.pdf), p. 8.
[13] Staffan Jacobsson, Bjorn A. Sanden, and Lennart Bangens, "Transforming the Energy System—the Evolution of the German Technological System for Solar Cells," *Technology Analysis & Strategic Management* 16:3–30 (2004), p. 9

significant government support for both technology development and market formation, which was forthcoming in successive decades from the U.S., Japan, and Germany.

From Space to Terrestrial Applications, 1954-1980

The photovoltaic effect, in which light is converted into electrical current, was first observed in 1839. However, it was not until 1954 that a PV device with an efficiency above 1% was invented and the effect became the focus of sustained inquiry by industrial scientists. In that year, scientists at Bell Labs demonstrated a working solar cell with an efficiency of 6%. Within two years, they were able to roughly double its efficiency, setting a standard that was maintained for the next decade.[14]

Although the Bell System supported research on solar cells with the goal of powering telecommunications devices in remote locations, it initially found them too costly for this purpose. Instead, the technology was taken up by the National Aeronautics and Space Administration (NASA), the Department of Defense (DOD) and the satellite industry, where electricity costs "at least three orders of magnitude above current U.S. wholesale rates" were no deterrent.[15] In 1973, about 10 kW of solar cell capacity with an efficiency of about 14% was produced for space applications.[16]

The oil crisis of 1973 triggered a serious push to develop terrestrial applications for PV, particularly in the U.S. and with Federal support. The Energy Research and Development Administration (ERDA) was established in 1974 and authorized to undertake a "vigorous federal program of research, development, and demonstration" for solar power, including PV.[17] ERDA estimated that solar power could provide as much as 20% of the nation's energy by 2020.[18] The PV R&D program expanded significantly during the Carter Administration, reaching $157 million in 1980.[19] The investment paid off, yielding significant breakthroughs in cell efficiency and cost reduction.[20] Figure 3 shows the concentration of PV technology breakthroughs made between 1975 and 1985 at government and academic laboratories in the U.S.

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[14] Morton B. Prince, "Early Work on Photovoltaic Devices at the Bell Telephone Laboratories" in Wolfgang Palz, *Solar Power for the World* (Singapore: Pan Stanford, 2014), pp. 199-201; Denis J. Curtin, "Solar Cell Development Work at COMSAT Laboratories (1967-1975)," in *ibid.*, pp. 275-278.

[15] Gregory F. Nemet, "Solar Photovoltaics: Multiple Drivers of Technological Improvement," in Arnulf Grubler and Charlie Wilson, eds., *Energy Technology Innovation: Learning from Historical Successes and Failures* (Cambridge University Press, 2014), pp. 206-217, quote from 210.

[16] Wolfgang Palz, "Rising Sun in a Developing World," in Palz, ed., *op. cit.*, pp. 31-107, p. 53.

[17] Justin A. Bereny, *Survey of the Emerging Solar Energy Industry, 1977 Edition* (San Mateo CA: Solar Energy Information Services, 1977), p. 19.

[18] Bereny, *op. cit.*, pp. 20-21. Frank N. Laird, *Solar Energy, Technology Policy, and Institutional Values* (Cambridge University Press, 2001) traces the debate over this figure (which includes solar sources of all types, not only PV) and associated programs in the Ford and Carter Administrations.

[19] Palz, *op. cit.,* p. 67.

[20] Frederick Schmid, "History of Technologies, Development of Solar Silicon Cost Reduction," in Palz, ed., *op. cit.*, pp. 257-274; Gregory F. Nemet, "Beyond the Learning Curve: Factors Influencing Cost Reductions in Photovoltaics," *Energy Policy* 34:3218-3232 (2006); J. David Roessner, "Commercializing Solar Technology: The Government Role," *Research Policy* 13:235-246 (1984); Vicki Norberg-Bohm, "Creating Incentives for Environmentally Enhancing Technological Change: Lessons from 30 Years of U.S. Energy Technology Policy," *Technological Forecasting and Social Change* 65:125-148 (2000).

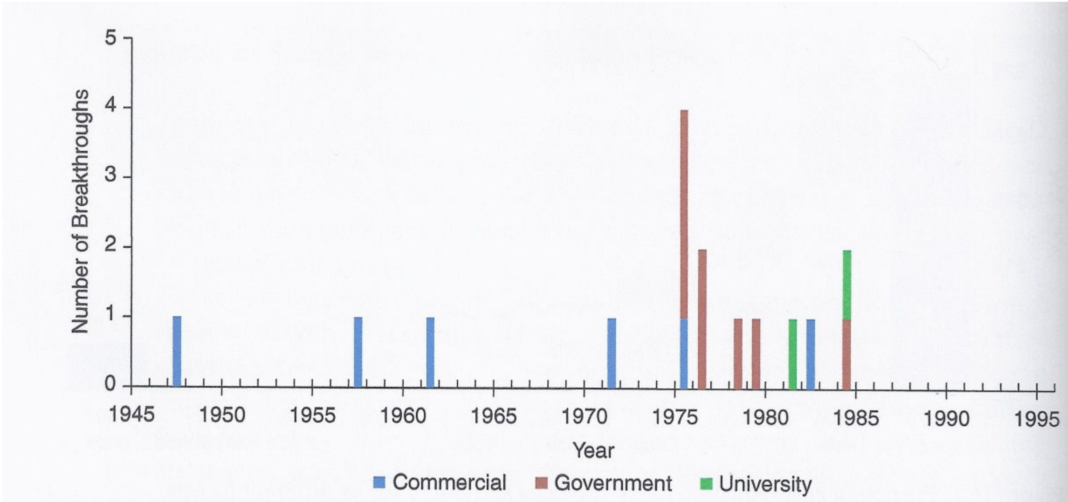

Figure 15.2. Frequency of breakthroughs in PV technology by origin.
Sources: Husmann (2011); Nemet and Husmann (2012).

FIGURE 3: Breakthroughs in PV Technology by Institutional Origin[21]

Federal policy supported deployment of PV as well as RD&D. Federal agencies purchased almost 2000 kW of capacity between 1977 and 1980.[22] The Public Utility Regulatory Policy Act of 1978 (PURPA) forced opened a significant market for small generating facilities, including some solar facilities, requiring utilities to take their power and compensate them at a high rate.[23] Also in that year, Federal tax incentives were put in place for the purchase of solar equipment by home and business owners; these incentives were expanded in 1980 and were complemented by state tax credits in more than half of the states.[24] Cost reduction powered by R&D breakthroughs and manufacturing process improvements combined with incentives to bring additional niche markets within reach of PV systems, not only for telecommunications, but also navigational aids and off-grid homes. These sources of demand stimulated about a half-dozen manufacturers to build PV module factories in the U.S. in the late 1970s, often with investment from major energy companies.[25]

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[21] Nemet 2014, *op. cit.*, p. 209.
[22] Palz, *op. cit.*, p. 68.
[23] Jeremiah D. Lambert, *The Power Brokers* (MIT Press, 2015), p. 139.
[24] Daniel Rich and J.David Roessner, "Tax Credits and U.S. Solar Commercialization Policy," *Energy Policy* 18:186–198 (1990) review literature evaluating the credit but do not break out the impact on PV as opposed to other solar technologies that qualified. Margaret Taylor, "Beyond Technology-Push and Demand-Pull: Lessons from California's Solar Policy," Goldman School of Public Policy GSP 08-002, University of California, Berkeley, 2008, provides a detailed account of the California incentives.
[25] Palz, op. cit., pp. 66-68; Peter F. Varadi, "Terrestrial Photovoltaic Industry: The Beginning," in Palz, ed., *op. cit.*, pp. 203-218; Nemet 2014, *op. cit.*, p. 210. Varadi's account places much greater weight on R&D and procurement policy than tax incentives.

A Dormant Period: Shifting Global Leadership through the Early 2000s

U.S. global leadership in PV deployment as well as production came to an end in the early 1980s.[26] Dropping oil and gas prices considerably sharpened the cost reduction challenge as well as reducing public interest in energy policy in the U.S. The Reagan Administration, reflecting its conservative ideology as well as changing political and economic conditions, slashed RD&D funding by the Department of Energy (ERDA's successor) and ended the Federal "block buy" of PV systems from qualified manufacturers.[27] Federal tax incentives were allowed to expire in 1985 before being partially restored for businesses only in 1986.[28] According to Peter F. Varedi, co-founder of Solarex, a PV manufacturer founded in 1973, Reagan's policies "had a great effect on PV companies, whose primary customer was the U.S. government."[29] Only two companies survived, and only because they had developed markets outside the U.S.

While PV deployment in the U.S. slowed considerably, other countries picked up the baton in what became a global relay race over the next couple of decades. Japan made PV a top R&D priority among renewable energy resources starting in the 1980s. In the early 1990s, it began to focus on deployment through the "New Sunshine" policy, instituting 50% subsidies for the upfront cost of PV systems and encouraging net metering. "Right from the beginning, the programme was quite successful: between 1995 and 1997 the domestic market increased ten-fold to 37 MW."[30] By 2000, Japan's installed PV capacity was 330 MW, the most of any country.[31] As was to be the case in other jurisdictions, the rapid uptake of subsidies put pressure on the program's budget, prompting cutbacks during the 2000s.[32] (See figure 4.) Nonetheless, the long-term vision of the program and planned declines in the subsidy levels helped to drive scale economies in PV production.[33]

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[26] "A market contraction in the USA was somewhat balanced by developments in other parts of the world, in particular by the increasing numbers of solar cells produced in Japan for consumer electronics products, but the era of unlimited solar optimism was over. In the period from 1983 to 1996 the market grew on average by only 13% per year. The consumer product segment grew initially, but it was the commercial off-grid power markets, much of it in developing countries, that dominated the period." Jacobsson, *et al., op. cit.*, p. 9. A 1990 DOE report estimated the consumer electronics segment of the PV market at that time to be "more than 5 MW per year." Idaho National Engineering Labs (INEL) *et al.*, "The Potential of Renewable Energy: An Interlaboratory White Paper," SERI/TP-260-3674, March 1990, p. G-1.

[27] Bradford, *op. cit.*, p. 98.

[28] Rich and Roessner, *op. cit.*

[29] Varedi, *op. cit.*, pp. 217-218.

[30] Palz *op. cit.*, pp. 80-83, quote from p. 82.

[31] Anthony Patt, *Transforming Energy: Solving Climate Change with Technology Policy* (Cambridge University Press, 2015), p. 233.

[32] Thomas Hale and Johannes Urpelainen, "When and How Can Unilateral Policies Promote the International Diffusion of Environmental Policies and Clean Technology?," *Journal of Theoretical Politics* 27:177–205 (2015), pp. 196-197.

[33] Nemet 2014, *op. cit.*, p. 212.

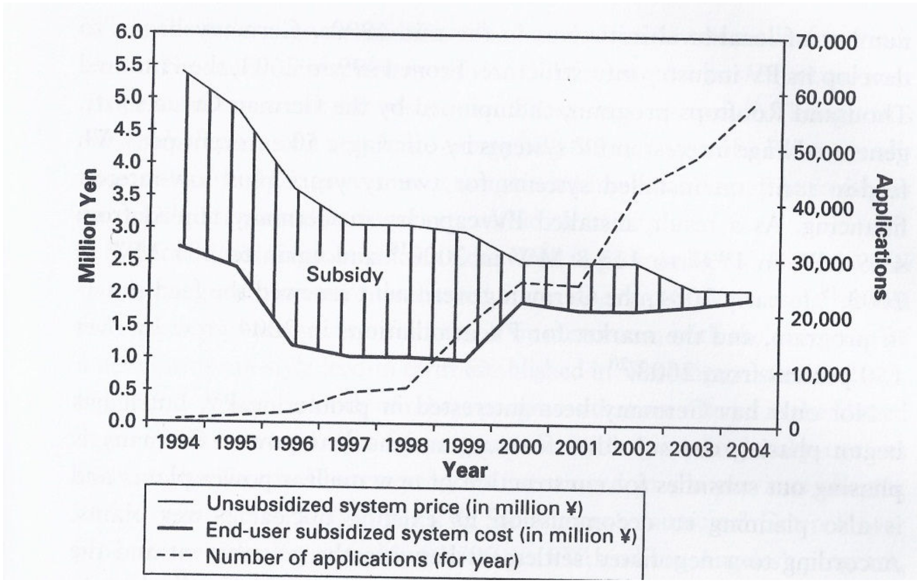

Figure 4: Subsidized and Unsubsidized PV System Costs and Applications, Japan[34]

As Japan's PV deployment slowed, Germany picked up the baton. The key policy innovation in Germany was the feed-in tariff (FIT), which guaranteed system owners high rates over long payback periods for supplying power to the grid.[35] A 1990 FIT led to a nearly hundred-fold increase in wind power capacity, but, despite a vigorous German RD&D program for PV, "solar energy remained the poor cousin of the renewable energy family, as the FIT rates barely covered 10% of PV energy production costs."[36] A more generous FIT for PV, building on local initiatives in Aachen and elsewhere, was enacted in 2000. Low-interest loans from the state bank KfW complemented the FIT. The policy was adjusted further and renewed in 2004, and by 2007, Germany's PV capacity had grown fifty-fold since 2000.[37] Many other countries, such as Spain and China, followed Germany's FIT model. As figure 5 shows, 38% of global installed PV capacity was in Germany in 2008.

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[34] Bradford, *op. cit.*, p. 179.
[35] Patt, *op. cit.*, pp. 229-230.
[36] Frank N. Laird and Christoph Stefes, "The Diverging Paths of German and United States Policies for Renewable Energy: Sources of Difference," *Energy Policy* 37:2619–2629 (2009), p. 2622; Jacobsson, Sanden, and Bangens, *op. cit.*, pp. 12-17.
[37] Laird and Stefes, *op. cit.*, p. 2624.

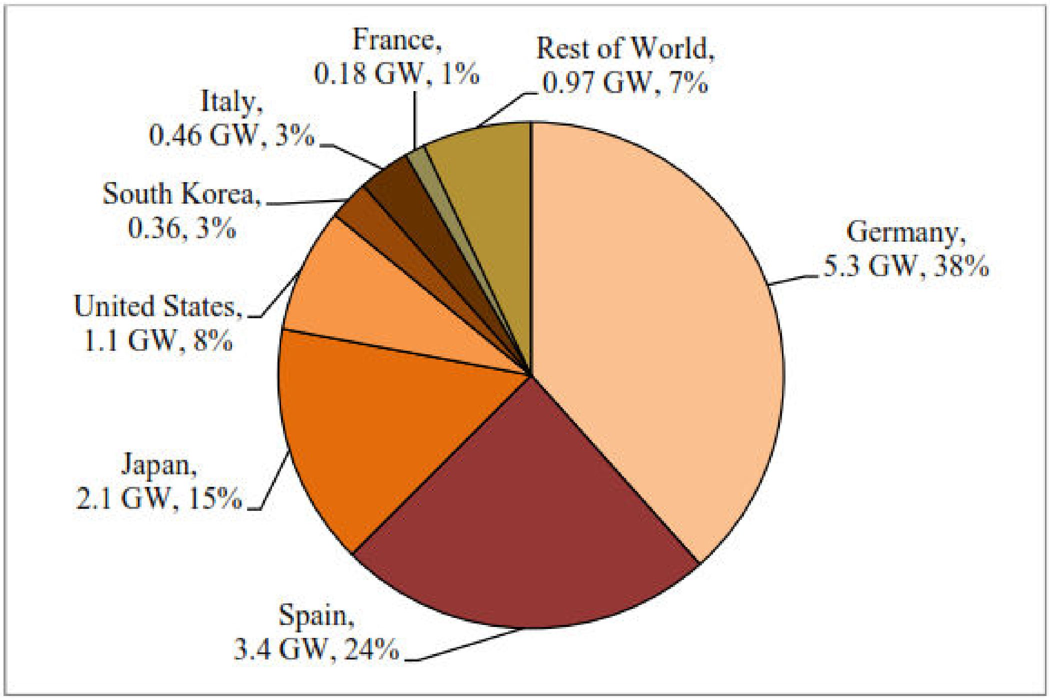

Figure 1.1 Global cumulative installed PV capacity through 2008
(EurObserv'ER 2009, IEA 2009, Mints et al. 2009, Sherwood/IREC 2009)

Figure 5: Global Cumulative Installed PV Capacity Through 2008[38]

All three "runners" in the global relay race of PV deployment through the early 2000s – the U.S. in the 1970s, Japan in the 1990s, and Germany in the 2000s – took their successive leads because they combined supply-push with demand-pull policies. Outside of a few niches in which buyers were willing to pay much higher prices than typical electricity consumers, PV was too costly in these decades to diffuse through the market mechanism alone. Each of the three countries led the world in public RD&D funding for PV for a period preceding or during its boom in domestic deployment.[39] Each invested significant public resources, albeit through different mechanisms, to give PV a foothold among end users for conventional applications. This "virtuous" or "positive feedback" cycle, in which multiple PV policies led to a "sense of commitment that convinced many to work on the technical and market challenges associated with commercializing this nascent technology," would be echoed across the U.S. later in the 21st century.[40]

[38] U.S. Department of Energy, *2008 Solar Technology Markets Report*, *op. cit.,* p. 1. This figure includes off-grid capacity.
[39] Jacobsson *et al.*, *op. cit.*, p. 9.
[40] Nemet 2014, *op. cit.*, p. 213.

4. PV Deployment in the 2000s

In the 2000s, PV deployment in the U.S. accelerated considerably. While cumulative deployment in this country remained well behind that in Germany Japan, and even Spain (see figure 5 above, which shows these four countries with 85% of the installed capacity in 2008), it became the fourth member of the gigawatt club by the decade's end; installed capacity grew at least fifty-fold in a roughly ten year span.[41] As in other countries and in earlier decades, public policy in the form of subsidies, incentives, and mandates drove deployment. Initially triggered by rising fossil fuel prices, these policies were sustained and even strengthened over the decade. While costs did not decline as rapidly as in the past, technological and institutional progress continued, setting the stage for a further leg up in the PV deployment curve in the 2010s.

Overall Deployment Trends

While data before 2000 are sparse, whatever momentum that had been built in PV deployment during the 1970s was spent by some point in the next decade as the Reagan Administration's policies took hold. A 1990 DOE report noted that off-grid applications at that time "account for the vast majority of the sales by U.S. industry," while utilities were merely "buying PV for testing purposes."[42] That was still true in 2000 (see figure 2 above.) Figure 6 shows the deployment pattern for grid-connected PV in California, by far the largest U.S. market, highlighting the acceleration around the turn of the century.

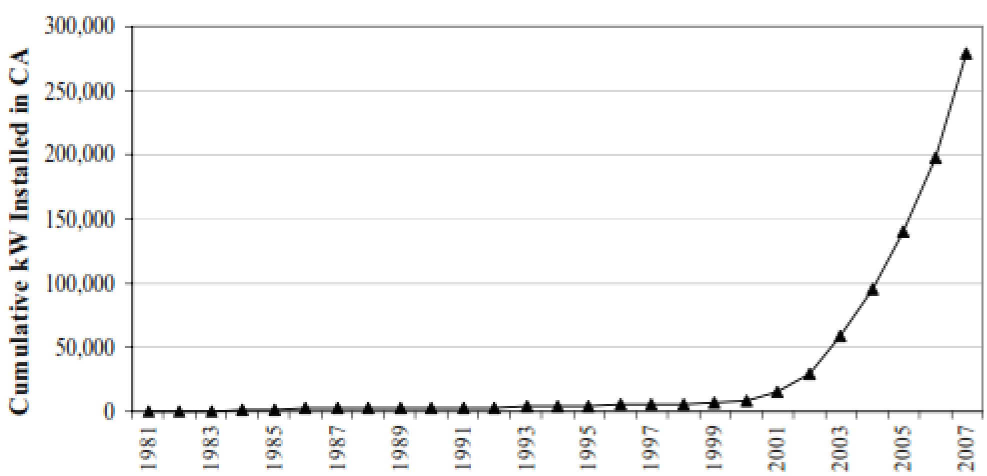

Figure 6: Cumulative Grid-Connected PV Capacity in California, 1981-2007[43]

The BP data for the nation for 1996-2000 show an average growth rate for PV installed capacity of less than 10% per year.[44] From 2001 to 2009, by contrast, the average growth rate was about 60% per year, with the fastest growth in 2003 of roughly 100%.[45] (See figure 7.)

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[41] As noted in section 2, the BP and IREC/GTM/SEIA datasets are not entirely consistent, particularly from 1998 to 2005, which is the starting point for this calculation. The fifty-fold growth period may begin in 1999, 2000, or 2001, depending on which figures are used, with an end date in 2009 in all cases. Although figure 5 includes off-grid capacity, the U.S. had more than 1 GW of grid-connected capacity by 2009.

[42] INEL, *op. cit.*, p. G-1 to G-2.

[43] Taylor, *op. cit.*, p. 7, citing data from the California Public Utility Commission.

Installed photovoltaic (PV) power (MW)										
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Cumulative	18.5	21.9	28	73	111	190	295	455	753	1188
Annual	2	3	6	45	38	79	105	160	298	435
Growth rate	11%	18%	28%	161%	52%	71%	55%	54%	65%	58%
5 year average growth rate		10%	14%	46%	54%	66%	73%	79%	60%	61%

Figure 7: Installed PV Capacity in the U.S., 2000-2009[46]

System Costs

The bending of the deployment curve around 2001 and its new trajectory after that were not triggered by an abrupt change in the relative price of PV-generated power compared to that of other sources. As Figure 8 shows, there is no break in installed PV system prices at that time. In fact, the decades-long price decline, which had been steady in the late 1990s and early 2000s, slowed in the later part of the 2000s as modules drifted far above their historic cost-reduction experience curve. (See figure 16 in section 5.) "From 1998-2005, average costs declined at a relatively rapid pace, with average annual reductions of $0.4/W, or 4.8% per year in real dollars. From 2005 through 2007, however, installed costs remained essentially flat."[47]

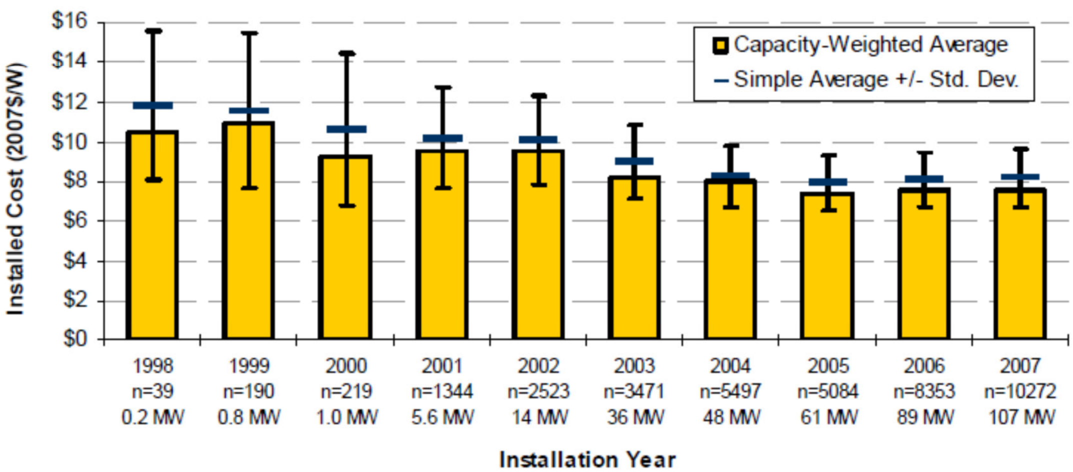

Figure 8: Installed Cost Trends for Photovoltaic Systems in the U.S., 1998-2007[48]

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[44] Other sources indicate growth rates in the 1980s and 1990s of up to 15% per year. Jacobsson *et al.*, *op. cit.*, p. 9; Jeffrey A. Serfass, Michael K. Bergman, and Wendy Rodenhiser, "Commercial, Environmental and Legislative Factors that Influence the Implementation of Fuel Cells, *Journal of Power Sources* 49:193-208 (1994).

[45] The BP data for 2001-2009 show average annual growth of 63% per year; the IREC data show 56%. Shayle Kann, "Emerging Trends in the U.S. Solar Market," GTM Research, November 2009, p. 2, calculates a 71% compound average growth rate for these years. 2003 is the year with the fastest growth in both datasets with BP reporting 161% growth and IREC reporting 78% growth.

[46] BP, *op. cit.*

[47] Ryan Wiser, Galen Barbose, and Carla Peterman, *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007* (Berkeley: Lawrence Berkeley National Laboratory, 2009), p. 9. The stagnation continued through 2009, as later installments of this annual report show.

[48] Wiser *et al., op. cit.*

Even in a state like New Jersey, which had relatively high electricity rates by U.S. standards, the cost of unsubsidized solar power was estimated to be at least twice the average rate in 2008, and possibly five times as much, depending on the financial and meteorological assumptions used.[49]

Fossil Fuel Prices and the California Energy Crises: Probable Policy Triggers

As described below, a series of somewhat unconnected policy measures overcame this cost barrier to spur deployment during the decade. While it is difficult to pinpoint an exact connection, it seems likely that, as in the 1970s, an unexpected rise in the price of oil helped to trigger these policy changes.

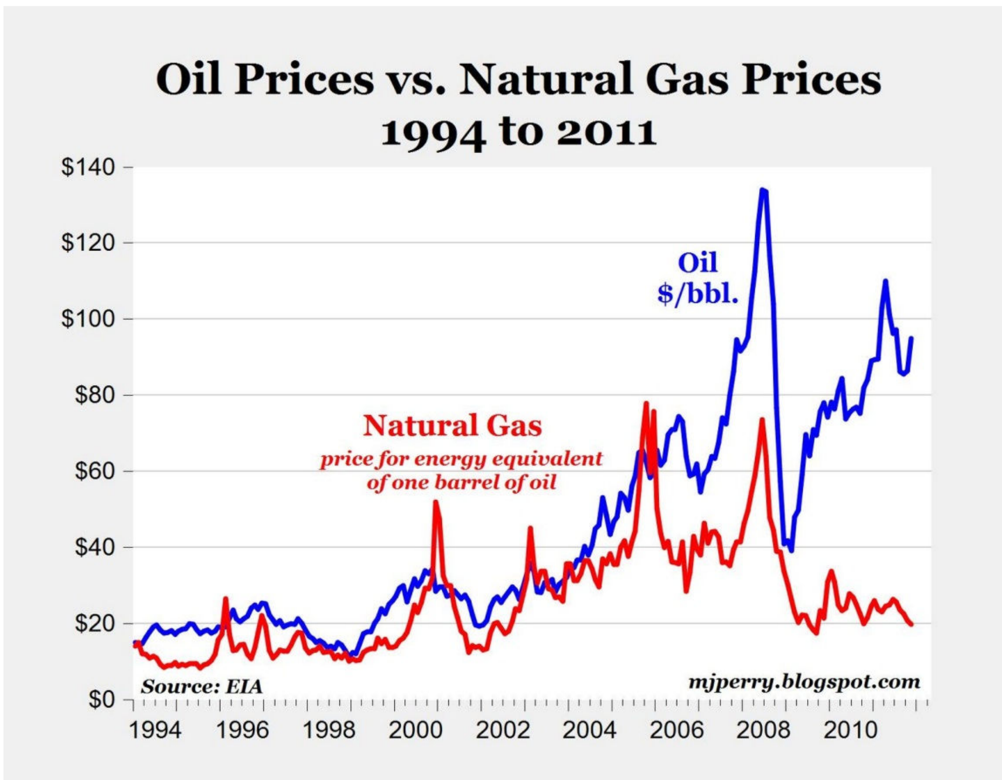

Figure 9: Oil and Natural Gas Prices 1994-2011[50]

Figure 9 displays the spike in oil and natural gas prices that occurred in 2001. The price of oil continued to rise until the recession hit in 2008. The price of natural gas, which competes more directly with PV as a fuel for power generation, peaked in 2005 and then leveled off, foreshadowing a more drastic divergence between these two prices series at the end of the

[49] David M. Hart, "Making, Breaking, and (Partially) Remaking Markets: State Regulation and Photovoltaic Electricity in New Jersey," *Energy Policy* 38:6662-6673 (2010).

[50] Data compiled from EIA by Mark J. Perry, *Carpe Diem* (blog), November 19, 2011 (http://mjperry.blogspot.com/2011/11/charts-of-day-oil-vs-natural-gas-prices.html), accessed May 20, 2016.

decade as the shale gas boom hit the market. Nonetheless, natural gas roughly doubled in price before and after the 2001 spike.

A related contributing factor was the electricity crisis that led to rolling blackouts and dramatically higher prices in California in 2000-2001. "Average PX prices for wholesale power reached the previously unthinkable level of $166 per megawatt-hour. Annual statewide electricity costs totaled $27 billion [in 2000] compared with $7 billion in 1999."[51]

These events, along with the 9/11/2001 terror attacks and the ensuing Iraq War, drew renewed attention to energy policy and helped, over a periods of several years, to provoke changes in it at the Federal and state levels. As Larry Sherwood of IREC pointed out in his 2007 *Solar Market Trends* report, explaining the rapid growth in PV deployment: "Energy prices generally, and electricity prices specifically, continue to increase, and consumer concern about rising energy costs is high."[52] These concerns were heard by policy-makers.

Deployment by Market Segment
Figure 10 shows the breakdown of grid-connected PV capacity deployed each year by market segment. Non-residential capacity made up the largest share of the market throughout the period, but its growth levelled off at the end of the decade. The growth of residential installation, by contrast, was basically steady throughout the decade. Utility PV deployment appears for the first time in these data only in the last two years of the decade. "Other than the SEGS I-IX parabolic trough concentrating solar power projects built in the 1980s, virtually no utility-scale PV, CPV, or CSP projects existed in the United States prior to 2007."[53]

[51] Lambert, *op. cit.* p. 191.
[52] Larry Sherwood, *Solar Market Trends 2007*, Interstate Renewable Energy Council, August 2008, p. 4.
[53] Bolinger and Seel, *op. cit.*, p. 38.

Fig. 2: Annual Installed Grid-Connected PV Capacity by Sector (2000-2009)

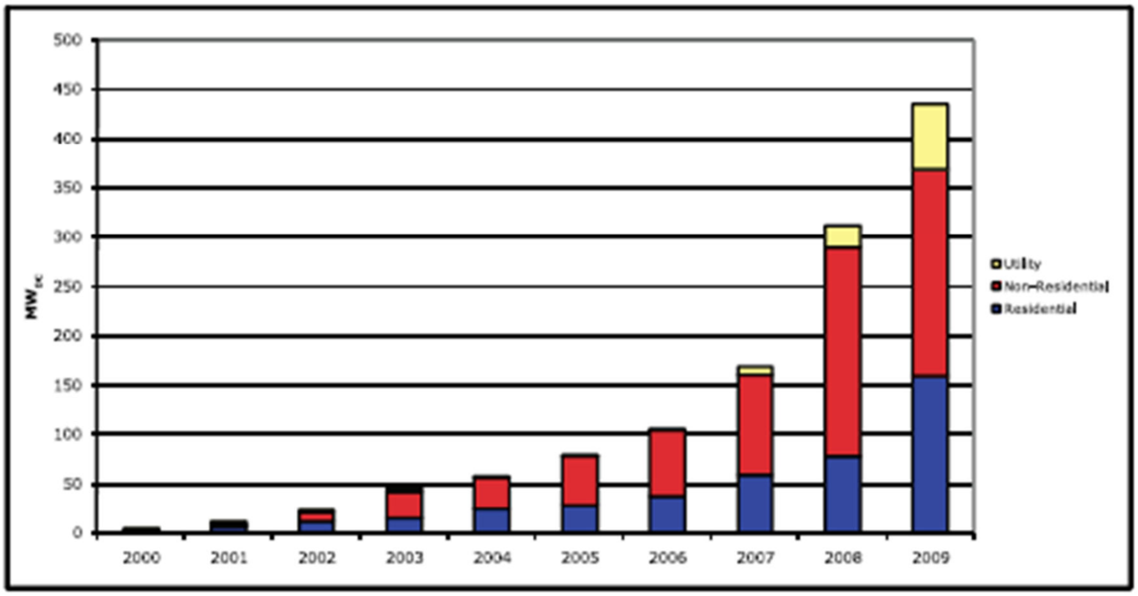

Figure 10: Annual Installed Grid-Connected PV Capacity by Market Segment, 2000-2009[54]

Idiosyncratic factors shaping the decisions of individual buyers of large systems (by the standards of the day) may be visible in the national data in such a thin market. For example, a 14 MW system at Nellis Air Force Base in Nevada and an 8 MW system in Alamosa, Colorado, that were installed in 2007 would have made up a sizable fraction of the non-residential segment in that year.[55] Similarly, two large systems in 2008 and 2009 accounted for most of the installed capacity added in the utility sector in each of those years. [56]

However, more systematic techno-economic factors can also be identified. One is economies of scale, which favored the non-residential segment in particular. Larger systems had lower unit costs, with a gap of 20-30% between very large and very small systems estimated for 2007-2009.[57] On the other hand, when the recession struck in 2008, the credit squeeze made it difficult for commercial and industrial customers who make up the bulk of the non-residential market to get financing.[58] These two factors contribute to the growth and then slowdown of the non-residential segment. Utilities also benefited from economies of scale, once they were permitted by policy-makers to participate in the PV market in 2008, as discussed further below.

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[54] Sherwood, 2010, *op cit.*, p. 24.
[55] DOE 2010, *op. cit.*, p. 8.
[56] Larry Sherwood, *Solar Market Trends 2008*, Interstate Renewable Energy Council, July 2009, p. 4; Sherwood, 2010, *op. cit.* p. 25
[57] Wiser, *et al.*, *op. cit.*, p. 13; Sherwood, 2008, *op. cit.*, p. 4.
[58] Bolinger 2009, *op. cit.*, p. ix; Sherwood 2010, *op. cit.*, p. 25.

Federal Policy and the Non-Residential and Utility Segments
The Federal government did not respond as rapidly as California and other states to the change in the energy policy environment in the early 2000s, but in 2005 Congress passed the Energy Policy Act, which created a 30% investment tax credit (ITC) for residential purchasers of PV systems and raised the credit for business purchasers from 10% (where it had been since 1988) to 30%.[59] This shift had a pronounced effect on the non-residential segment, unlocking financing that allowed these customers to take advantage of the economies of scale noted above. The ITC was less beneficial for the residential segment, both because it was initially capped at $2000 and because state programs were scaled back in response. "The non-residential sector's commanding lead in terms of installed capacity in recent years," wrote Mark Bolinger of Lawrence Berkeley National Laboratory in 2009, "primarily reflects two important differences between the non-residential and residential markets: (1) the greater federal tax benefits...and (2) larger non-residential project size."[60]

The 2005 Act put the ITC in place through the end of 2007. It was extended through 2008 in late 2006, and then again through 2016 in October 2008.[61] Uncertainty about the durability of the credit contributed to short-term boom and bust cycles in which customers rushed to take advantage of it before its expected expiration.[62] Any deterrent effect of uncertainty seems to have been overshadowed by the incentive effect in the rapid growth of deployment. The ITC was complemented by accelerated depreciation, which added about 26% to the tax benefit, thus reducing the system cost by about 56% over a six year period for many investors.[63]

Further, Federal law permitted the emergence of new leasing and ownership models that allowed investors who were otherwise unconnected with the site or user of the system's power to reap these tax benefits. Financial institutions, such as banks and insurance companies, were thus able to participate as passive "tax equity" investors in the PV market. System revenues needed to pay back these investors were typically ensured through long-term power purchase agreements (PPAs). Additional mechanisms, such as municipal and clean renewable energy bonds, facilitated financing for PV systems on tax-exempt sites, such as schools and churches. "This financial innovation has single-handedly overcome some of the largest barriers to the adoption of PV; and, as such is largely responsible (along with the enhanced tax benefits that have driven this innovation) for the rapid growth in the [non-residential] market..."[64]

Utilities were not allowed to claim the ITC until its second renewal in late 2008. With their strong balance sheets, utilities did not necessarily need third party investment to take advantage of the credit. A DOE report noted that the eight-year term of the extension provided confidence to utilities considering PV investments; even if their projects took some time to get designed, sited, and built, the credit would be available. The report also noted that, to the advantage of utilities, the ITC "can also be applied to a renewable energy system owner's alternative

[59] Navigant Consulting, "Economic Impacts of Extending Federal Solar Tax Credits," September 15, 2008, p. 74.
[60] Bolinger 2009, *op. cit.*, p. i.
[61] Bolinger, 2009, *op. cit.*, p. 5.
[62] Sherwood 2009, *op. cit.*, p. 5
[63] Bolinger 2009, *op. cit.*, p. 6.
[64] Bolinger 2009, *op. cit.*, p. 3.

minimum tax—formerly a significant barrier to entry..."[65] Spurred as well by solar carve-outs within some states' renewable portfolio requirements (discussed below), the utility segment quickly jumped from negligible to 8% of the market in 2008 and 16% in 2009, foreshadowing its dominance after 2010 (see section 5).[66]

State Deployment Patterns, State Policies, and the Residential Segment

PV deployment was highly concentrated in a small number of states during the 2000s, when data at this level of aggregation first become available. (See figure 11.) From 2001 to 2006, the top five states accounted for more than 90% of all installed capacity. California was the leading state in each year from 2001 to 2009, accounting for over 80% of the total in some years and 60% for the decade. New Jersey was among the top five in each year as well, coming second from 2005 to 2009, with a share that peaked at 17% of the national total in 2006. Arizona was the second leading state from 2001 to 2004, before dropping to fifth in 2005 and then out of the top five altogether.

	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
California	7.4	17	31.6	43.7	51	69.5	91.8	197.6	212.1	721.7
New Jersey	0	0.8	0.8	2.1	5.5	17.9	20.4	22.5	57.3	127.3
Colorado	N/A	N/A	N/A	N/A	N/A	1	11.5	21.7	23.4	57.6
Arizona	2.6	2.2	3.4	2.3	1.5	2.1	2.8	6.2	21.1	44.2
Florida	N/A	N/A	N/A	N/A	N/A	0.3	1	0.9	35.7	37.9
Nevada	N/A	N/A	N/A	N/A	N/A	3.2	15.9	14.9	2.5	36.5
New York	0.2	0.9	2.1	1.4	1.3	3	3.8	7	12.1	31.8
Hawaii	N/A	N/A	N/A	N/A	N/A	0.7	2.9	8.6	12.7	24.9
Massachusetts	0	0	0.3	0.6	0.6	1.5	1.4	3.5	9.5	17.4
Oregon	0.1	0	0.2	0.4	0.4	0.5	1.1	4.8	6.4	13.9
Illinois	0.4	0.4	0.3	0.4	0.2	0.1	0.2	0.4	1.7	4.1
All others	1.4	2.2	2	3	3.1	3.4	6.9	22.7	40.3	85
Total	11.6	23.1	39.9	52.5	62.4	103.2	159.7	310.8	434.8	1198
% California	64%	74%	79%	83%	82%	67%	57%	64%	49%	60%
% New Jersey	0	3%	2%	4%	9%	17%	13%	7%	13%	11%
% California + New Jei	64%	77%	81%	87%	91%	85%	70%	71%	62%	71%
% top 5 states	92%	92%	96%	95%	96%	90%	85%	80%	62%	

Figure 11: Grid-Connected Installed PV Capacity by State, 2001-2009 (MW)[67]

This concentration points to the importance of state policies in shaping the deployment pattern. The decline in concentration in the top five state after 2005 very likely reflects the availability of Federal tax benefits. In addition, as noted above, a small number of large non-residential or utility-scale systems can have a large impact in this period, for instance lifting Nevada in 2007 and 2008 and Florida in 2009 into the top ranks.[68] Finally, the ITC did not provide significant benefits to residential customers, largely because of the $2000 cap. Therefore, we focus here on

[65] DOE 2008, *op. cit.*, p. 101
[66] Sherwood 2010, *op. cit.*, p. 25.
[67] Sherwood 2006, 2007, 2008, and 2009, *op. cit.*,. Data for 2001 to 2005 are available for the top 7 states only.
[68] It may also be worth noting that systems on Federal properties like the 14 MW array at Nellis Air Force Base that went into service in 2007 were not likely to have been influenced by state policy.

states that had a steady presence in the top tier and on their policies toward the residential segment, which comprised about a third of the market.[69]

State policies are not easy to summarize, unfortunately. The DSIRE database, which tracks them, currently lists 38 categories of state policy toward PV.[70] While not all of these policies had been created a decade ago, a 2008 DSIRE presentation identified 11 categories, the most important of which, financial incentives, was further subdivided into "Rebates, Grants, Production Incentives, Tax Credits & Deductions, Low-Interest Loans, Sales Tax Exemptions, Property Tax Incentives, and Local Permit Fee Waivers."[71] In addition, states changed their policies frequently. Figures 12 and 13, drawn from the same presentation, displays the growth in the number of states offering direct financial incentives for PV (rebates, grants, or production) from 6 in 1997 to 25 in 2007.

[69] Although no comprehensive data are available by segment before 2010, Sherwood 2010, *op.cit.,* p.5 states: "Residential capacity installed in 2009 more than doubled compared with capacity installed in 2008 and represented 36% of all new grid-connected PV capacity. This market share is consistent with residential installations in 2005, 2006 and 2007, and is significantly higher than the 27% market share for residential installations in 2008."

[70] DSIRE, "Summary Tables" filtered by technology "Solar Photovoltaics" (http://programs.dsireusa.org/system/program/tables), accessed May 22, 2016.

[71] Susan Gouchoe, "U.S. Photovoltaic Markets: PV Policies Leading the Way," ASES Annual Conference, May 2008.

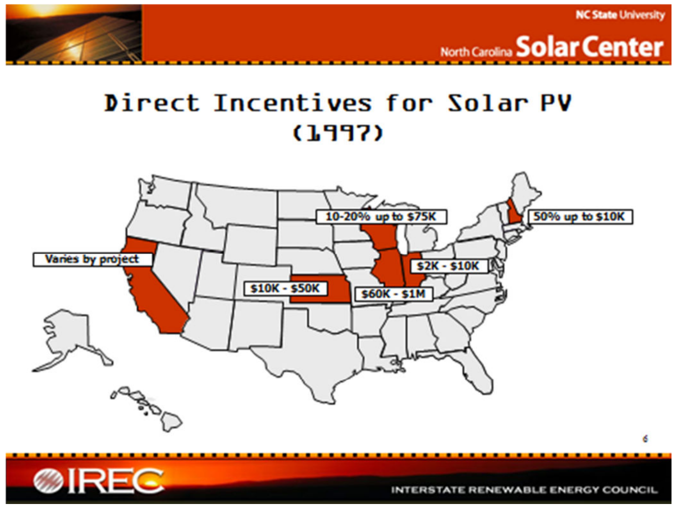

Figure 12: Direct Incentives for Solar PV: State Programs (1997)[72]

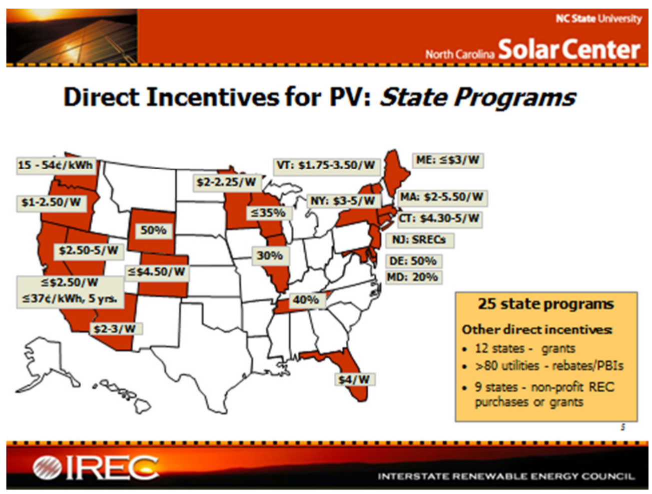

Figure 13: Direct Incentives for PV: State Programs (2007)[73]

Taylor (2008) divides California's policies into three broad categories ("upstream investment, market creation, and interface improvement"), each of which was further divided into three subcategories. She provides a detailed history of the policy's evolution, which is illustrated for 2006 (a year of complicated changes but not uniquely so) in figure 14.

[72] Gouchoe, *op. cit.*, slide 5
[73] Gouchoe, *op. cit.*, slide 4.

In January 2006, CPUC Chair Michael Peevey issued a decision (06-01-024) to establish the CSI as a program to "provide up to $2.8 billion in incentives for solar projects of all types and sizes over 11 years" in order to "bring on line or displace 3,000 MW of power" by 2017 (CPUC, 2005-06). The CSI replaces the solar portions of the ERP and the SGIP, although both the CPUC and the CEC remain important actors. The January decision also included an allocation "up to 5% of each year's adopted budget to [research, development, and demonstration] that explores solar technologies and other distributed generation technologies that employ or could employ solar for power generation and storage or to offset natural gas usage"; some of that money is to be used to study and build "market development strategies." In August, the CPUC decided the shape of its part of the program, which is IOU-administered and directs IOU-generated financial incentives ($2,167 million over ten years from utility revenues from gas and electric distribution rates) to existing homes and existing and new commercial, industrial, and agricultural properties in IOU service areas (CPUC, 2008b). Meanwhile, the CEC directs incentives ($400 million over ten years) to new home construction in IOU areas. An important aspect of the CSI program is that it represents a move away from installation incentives and toward so-called "performance-based incentives" (PBI), with some size-based distinctions regarding incentive levels (CPUC, 2008b). Starting in January 2007, projects greater than or equal to 100 kW are paid flat "monthly [PBI] payments based on recorded kW hours (kWh) of solar power produced over a 5-year period," while projects smaller than 50 kW are paid via an up-front incentive – the expected performance based buydown (EPBB) payment – "based on an estimate of the system's future performance" (CPUC, 2008b). Systems under 50 kW can, however, choose PBI payments. Meanwhile, beginning in January 2008, all projects 50 kW or larger must take the PBI. The CPUC expects that budgets in early years will be relatively high, dropping off over time "as rebate levels fall and, hopefully, as the market's need for financial support decreases." If demand exceeds targets, the CPUC plans to "automatically reduce incentive payment levels each year by 10% or more," while hopefully leaving staff experts flexibility regarding actual incentive reductions in any given year.[28]

SB 1, the "Million Solar Roofs" bill, raises the cap on net metering from 0.5% of peak aggregate demand to 2.5%, while stipulating that to truly achieve 3,000 MW of solar power from roofs (the estimated capacity of a million roofs), 5% will be necessary (EIA 2005). SB 1 also mandates that solar becomes a "standard option" for buyers of new homes by 2011, requires consideration by the CEC of mandating solar in all new construction, and reduces the CSI budget by $800 million to support municipal utilities in developing their own solar rebate programs (ibid.).

Figure 14: Solar Policy Chronology in California, 2006[74]

Given this complexity, it is not surprising that the literature that has applied quantitative methods to evaluate the impact of state policy has produced diverse findings. Gireesh Shrimali (perhaps the most prolific analyst in this field) and his co-authors noted in a 2012 paper that "Much work has been done in this area. However, results are contradictory, varying from showing the impact of RPS policies on renewable deployment as positively significant to insignificant to negatively significant."[75] As this quote suggests, most of the work in this genre has focused on renewables in general using renewable share of electricity generated as a dependent variable.

The more limited quantity of work focusing on PV in particular more consistently demonstrates an impact of state policy. In several studies covering the late 1990s and 2000s, for example, Shrimali and his co-authors found that cash incentives, renewable portfolio standards, and solar carve-outs within these standards "heavily influenced the market deployment of grid-tied solar

[74] Taylor, *op. cit.*, pp. 32-33.
[75] Gireesh Shrimali *et al.*, "Have State Renewable Portfolio Standards Really Worked? Synthesizing Past Policy Assessments to Build an Integrated Econometric Analysis of RPS Effectiveness in the U.S.," DIW Berlin discussion paper 1258, 2012, p. 3. A valiant effort to deal with this complexity can be found in Miriam Fischlein, "Renewable Energy Deployment in the Electricity Sector: Three Essays on Policy Design, Scope, and Outcomes," Ph.D. dissertation, University of Minnesota, 2010.

PV."[76] Steward *et al.*, using data from 2007 to 2011, and Stanford, using data from 2007 to 2012, also found support for these variables.[77]

These analyses support contemporaneous on-the-ground observations linking these policies to deployment. "Solar electric market activity has more to do with state incentives and policies than with the amount of available solar resources. All of the top states for grid-connected PV installations offer financial incentives and/or have a RPS policy with solar mandates. The combination of state and/or local incentives and the federal ITC has inspired most of the installations around the country. There are relatively few installations in locations with no state or local incentives or RPS policies with solar mandates." [78]

A brief look at the residential programs in California and New Jersey, the two states at the top of figure 11 provide further insight. California's major program for the first half of the decade imposed surcharges on investor-owned utilities that were funneled into rebates for buyers of PV systems. Through 2005, the Emerging Renewables Program for residential and small commercial systems had allocated funding for 50 MW of PV capacity, and the Self-Generation Incentives Program for larger systems, 113 MW.[79] These systems were connected to the grid through mandatory net metering, which was established in 1996 and which applied "particularly favorable time of use rates."[80] After evidence emerged that the capacity-based approach was producing somewhat perverse outcomes by allowing installers to capture part of the rebate, rather than driving down prices, the state shifted to a performance-based incentive under the California Solar Initiative in 2007, which led to 131% growth in installed capacity in 2008-2009.[81] California's RPS, although aggressive in general, did not contain a solar carve-out and therefore was perceived to have at most a modest effect on PV deployment before 2010.

New Jersey's solar program emerged from a 1999 restructuring of the electric power industry, in which utility companies were required to divest their generation assets. The restructuring law established an RPS and imposed a surcharge to support efforts to meet it. In 2004, a solar carve-out was added to the RPS, and a target of 90 MW of electricity generation from solar resources was established for the end of 2008. The funds generated by the surcharge were spent primarily on a rebate program that provided up to 70% of the initial cost of a PV system and was particularly generous to residential system purchasers. The installation push was supported by a

[76] Sarzynski, Larrieu, and Shrimali, *op. cit.,* p. 550; Gireesh Shrimali and Steffen Jenner, "The Impact of State Policy on Deployment and Cost of Solar Photovoltaic Technology in the US: A Sector-Specific Empirical Analysis," *Renewable Energy* 60:679-690 (2013); Gireesh Shrimali and Joshua Kniefel, "Are Government Policies Effective in Promoting Deployment of Renewable Electricity Resources?," *Energy Policy* 39:4726-4741 (2011).
[77] D. Steward, E. Doris, V. Krasko, and D. Hillman, "The Effectiveness of State-Level Policies on Solar Market Development in Different State Contexts," National Renewable Energy Laboratory, 2014; Virgil Stanford, "Rooftop Revolution: Comparative Effectiveness of State Policy Incentives for Solar PV Adoption in the Residential Sector," Ph.D. dissertation, George Mason University, 2014.
[78] Sherwood, 2009, *op. cit.*, p. 8. See also Ryan Wiser and Mark Bolinger, "Renewable Portfolio Standards: An Opportunity for Expanding State Solar Markets," November 2007; and the annual *Freeing the Grid* reports published by the Network for New Energy Choices.
[79] Taylor, *op . cit.,* p. 17. Presumably some of this capacity came on stream in 2006 or later, since these figures add up to more than that reported in Figure 11 through 2005.
[80] Taylor, *op. cit.*, p. 15.
[81] Taylor, *op. cit.*, pp. 17-18; Sherwood, *op. cit.*, 2010, p. 10.

net metering program that was hailed as a national model. Finally, PV system owners could supplement their income by selling Solar Renewable Energy Certificates to utilities, to be applied to their solar RPS carve-out requirement. The program was so generous that it was overwhelmed by demand, which led the state to scale back and ultimately transform its program into one that relied much more heavily on large systems, including those owned by utilities, by 2009.[82]

A Major Player Once More
In the 2000s, the U.S. once again became a major player in the global PV deployment process. Complementary (but not necessarily coordinated) Federal and state policies allowed system purchasers to take advantage of gradually improving, but not yet economically competitive technology. Federal tax incentives were particularly beneficial to the non-residential and newly emerging utility segments, while state financial incentives, solar RPS carve-outs, and net metering aided residential customers as well. Business model innovation in the form of new leasing and ownership models also played a vital role, a process that would expand in the 2010s.

5. PV Deployment in the 2010s

PV deployment in the current, incomplete decade already dwarfs that of the 2000s. The continued rapid growth of the market, despite the much larger installed base, correlates with the resumption of cost declines after a pause in the late 2000s. While the correlation is powerful, it masks subtler trends driving variation in deployment across segments and locations and over time. The utility segment, enabled by low costs, spurred by ambitious state targets, and supported by Federal tax incentives, has superseded the non-residential segment over the past six years. Relying mainly on utility segment deployment, southeastern states like North Carolina and Georgia joined the leaders for the first time. Growth in other segments also reflected state policy priorities, such as the residential segment in New York. California remained the bedrock of the national market, leading nearly every year across all segments. Growing familiarity with PV technology and improved financing options also helped to sustain deployment growth, especially in the residential segment.

Overall Deployment Trends
2009 marked an inflection point in PV deployment in the U.S. In that year, cumulative grid-connected installed capacity surpassed 1 GW. After slowing at the end of the 2000s, growth accelerated again in 2010, hitting nearly 100% in 2011. More than 24 GW of capacity was installed between 2010 and 2015, with an average annual growth rate of more than 70%. [83] (See Figure 15.) In late 2015, the federal investment tax credit was extended through 2023, firming up expert forecasts of continued strong growth in the short- and medium-term.

[82] This capsule is derived from Hart, 2010, *op. cit.*
[83] BP has not yet published its figures for 2015; GTM/SEIA data show 7260 MW added in 2015, 40% annual growth, and a cumulative installed base of 25,565 MW.

Installed photovoltaic (PV) power (MW)					
	2010	2011	2012	2013	2014
Cumulative	2040	3959	7328	12079	18280
Annual	852	1919	3369	4751	6201
Growth rate	72%	94%	85%	65%	51%
5 year average growth rate	61%	69%	75%	75%	73%

Figure 15: Installed PV Capacity in the U.S., 2010-2014[84]

System Costs

Among the most important factors driving PV deployment in the current decade is the rapid decline in system prices. "Starting in 2009, installed prices resumed their descent and have fallen steeply and steadily since, with average annual declines of 13% to 18% per year..."[85] In 2009, according to GTM Research, the average cost per watt for a ground-mount, fixed tilt PV system was approximately $4.80, compared with $1.45 in 2015, a cumulative decline of about 70%. Figure 16 displays the trend as well as a projection of future declines.

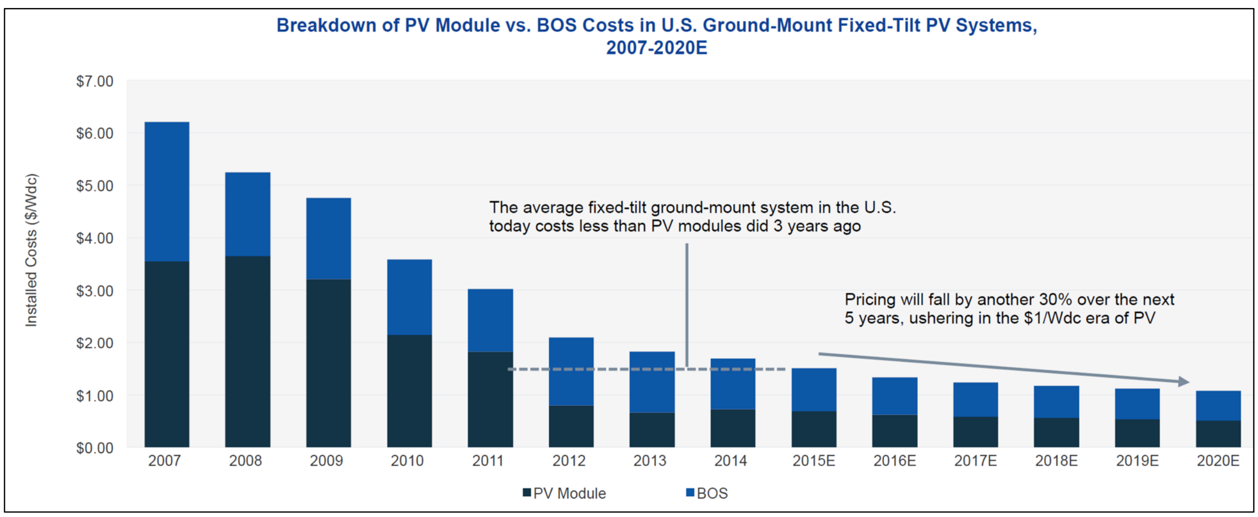

Figure 16: Average Cost Per Watt of Ground-Mount Fixed-Tilt PV System in the U.S.[86]

As figure 17 shows, costs for modules in this period returned to the negative exponential trend line established in prior decades after deviating from this path in the prior period. A key contributor to the acceleration of module cost reduction was the shift of production to China. By 2014, China was the source of over 66% of all modules produced globally. Efficiency improvements also contributed. "In the last 10 years, the efficiency of average commercial

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[84] BP, *op. cit.*

[85] Galen Barbose and Naim Darghouth, *Tracking the Sun VIII*, Lawrence Berkeley National Laboratory and Sunshot, August 2015, p. 15. LBNL and GTM use different samples for price estimation.

[86] M. J. Shiao, "PV Balance of Systems 2015: Technology Trends and Markets in the U.S. and Abroad," GTM Research, August 2015, p. 9.

wafer-based silicon modules increased from about 12 % to 16%."[87] Figure 18 suggests that 2010 marked a turning point in the efficiency of modules in the U.S.

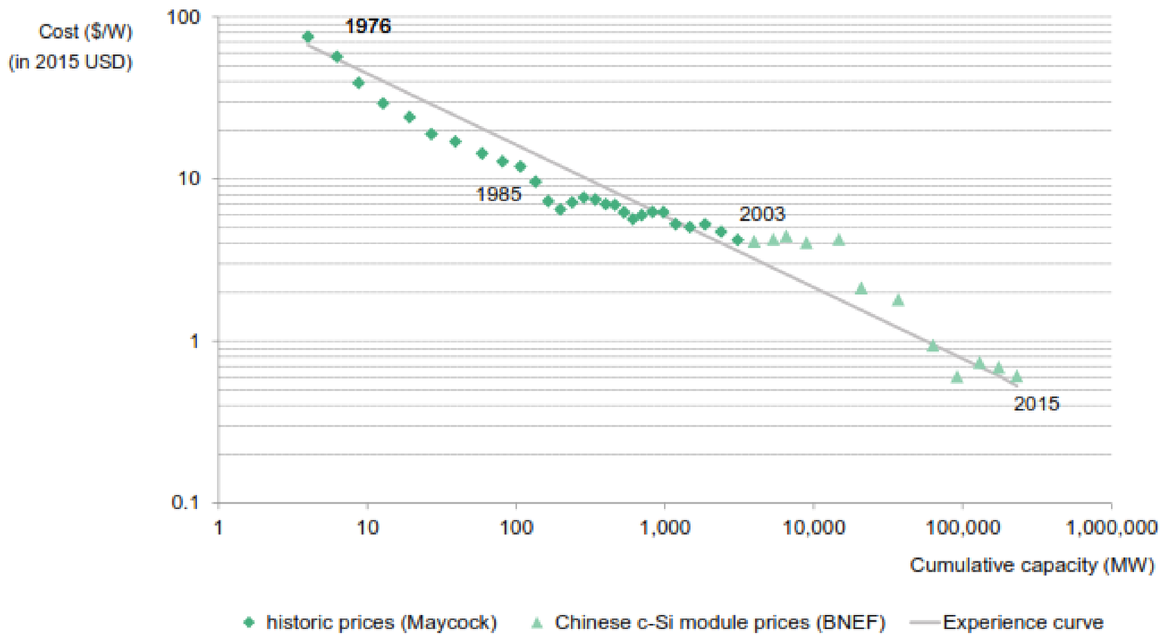
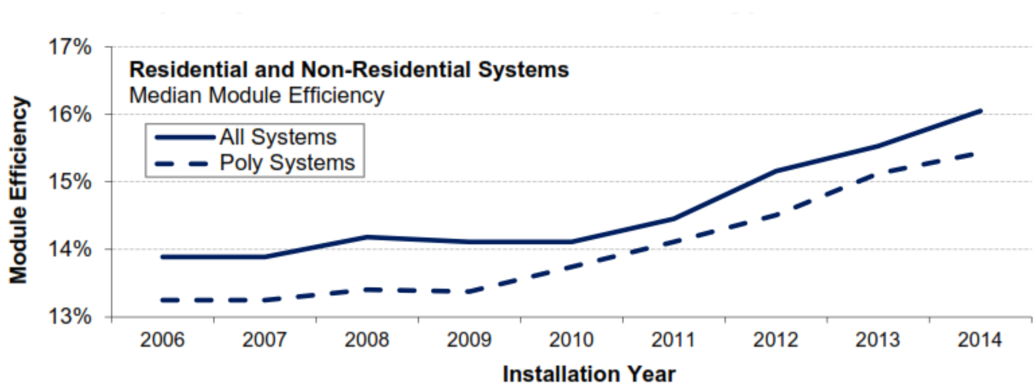


Figure 17: Experience Curve for PV Modules[88]



Notes: "All Systems" is based on all residential and non-residential systems in the data sample, regardless of module technology, while "Poly Systems" is based on only those systems with poly-crystalline modules. The figure is based on data from 200,930 systems installed over the 2006 to 2014 period, for which module efficiencies could be identified.

Figure 18: Median Module Efficiency, Residential & Non-Residential Systems, 2006-2014[89]

[87] Fraunhofer Institute for Solar Energy Systems, "Photovoltaics Report," March 11, 2016, p. 6 and p. 11.
[88] Business Council for Sustainable Energy and Bloomberg New Energy Finance, *2016 Sustainable Energy in America Factbook*, p. 56
[89] Barbose and Darghouth, *op. cit.,* p. 18.

As module costs dropped rapidly, balance of system costs became a larger share of the total, rising from about 60% of the cost to about 75% from 2010 to 2015. Nonetheless, average balance of system cost per watt declined by about 50% in this period.[90]

Deployment by Market Segment

The growth of the utility segment is the most distinctive feature of this period. During 2010, the annual capacity deployed in this segment was roughly the same as in the residential segment, and it was less than in the non-residential segment. During 2015, roughly twice as much utility PV capacity was deployed as residential capacity and four times as much as non-residential capacity. For the period as a whole, utility deployment comprised well over half of the national total. (See figures 19 and 20.)

Residential deployment grew at an average annual pace of over 50% in this period. More than 5 GW of capacity was installed (including more than 2 GW in 2015 alone), about 25 times as much as the previous cumulative total. The non-residential segment, by contrast, slowed significantly. Its contribution to national PV deployment dropped from 40% of the total in 2010 to only 14% in 2015. While the other two segments experienced accelerating growth during much of the decade to date, non-residential segment growth decelerated from 2011 to 2013 and declined in 2014 and 2015.

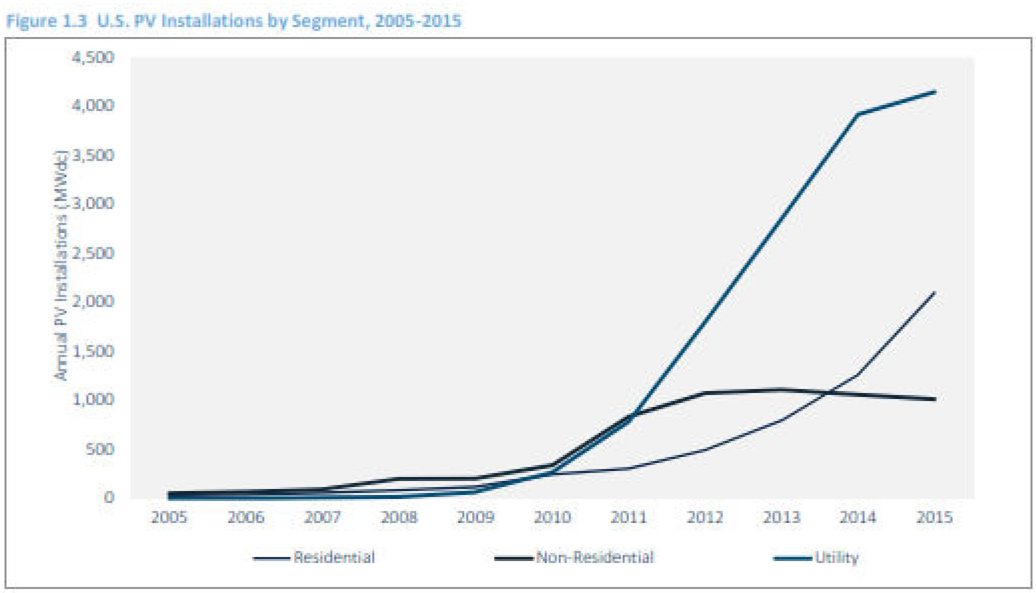


Figure 19: Annual PV Installations by Segment, 2005-2015[91]

[90] Shiao, *op. cit.,* p. 8
[91] GTM 2016a, *op. cit.*, p. 7

	2010	2011	2012	2013	2014	2015	2010-2015
Non-Residential - annual growth (MW)	339	835	1075	1110	1061	1011	5431
Utility - annual growth (MW)	267	784	1803	2855	3922	4150	13781
Residential - annual growth (MW)	246	305	494	796	1264	2099	5204
Non-Residential- % share national	40%	43%	32%	23%	17%	14%	22%
Utility- % share national	31%	41%	53%	60%	63%	57%	56%
Residential - % share national	29%	16%	15%	17%	20%	29%	21%
Non-Residential- annual growth		146%	29%	3%	-4%	-5%	
Utility- annual growth		194%	130%	58%	37%	6%	
Residential - annual growth		24%	62%	61%	59%	66%	

Figure 20: Annual PV Installations by Segment with Shares & Growth Rates, 2010-2015[92]

Costs by Market Segment

Detailed data on average cost per watt by market segment are available beginning in 2010.[93] As Figure 18 shows, while costs declined across all three segments, significant and sustained differences remain among them. Utility systems are the least expensive on a unit basis, and residential, the most, with non-residential in between. The absolute difference in the cost between utility and residential systems remained fairly steady through this period, meaning that the relative difference grew significantly. By 2015, the average cost of a utility system was less than half the cost of its residential counterpart.

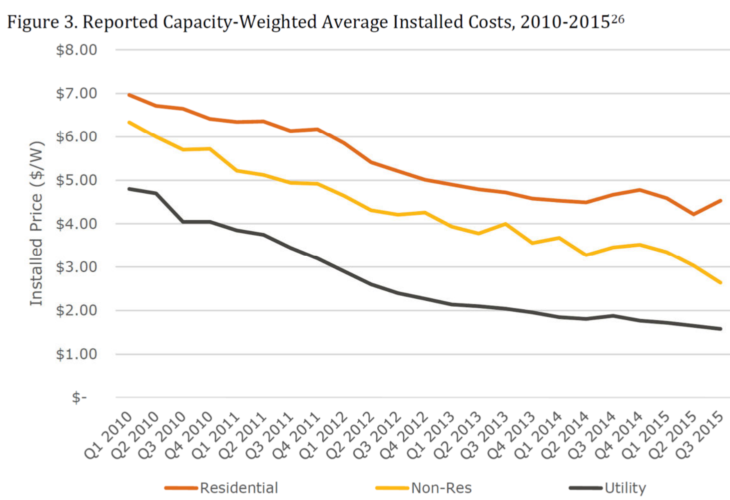


Figure 21: Average Installed Costs of PV by Segment[94]

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[92] IREC/GTM/SEIA data set, *op. cit.*

[93] These cost data are consistent with the category data; both are produced by GTM. Barbose and Darghouth *op. cit.*, p. 15, also provide segmented cost data, but their segments differ from GTM's, as discussed in section 2. It is possible that the non-residential and utility categories are not perfectly consistent over time, which would introduce error into the reported capacity, shares, and costs. That said, the costs reported by Barbose and Daghouth are consistent with GTM's, showing residential systems to be the most expensive and large non-residential systems to be slightly more than half the cost of residential systems in 2014.

[94] Assembled by The Solar Foundation (*National Solar Jobs Census 2015*, January 2016, p. 14) from GTM/SEIA data.

A comparison of figures 19 and 21 makes clear that price and capacity growth are not correlated at the segment level. As in the 2000s, policy factors are crucial for understanding how prices impacted deployment in the 2010s.

Utility Segment Deployment

As section 4 noted, utilities became eligible to claim the federal ITC in late 2008. Affirming Bolinger's (2009) early impressions, Cox and her colleagues concluded in 2015 that the ITC was "an instrumental driver of utility-scale projects in the U.S."[95] The revival of the "tax equity" market, as large financial institutions returned to profitability during the broader recovery of the U.S. economy, allowed the ITC to be used on a large scale.[96] In fact, tax rules made it more likely that third parties would own utility-scale solar PV projects and sell their output to utilities or other large customers under PPAs than that utilities would own such projects. "While independent power producers can monetize the ITC at a project's commercial operation, investor-owned utilities have to evenly spread ITC benefits over the lifetime of the system..."[97] Uncertainty about the future of these incentives shaped the deployment pattern over time, with the expected decline in the ITC to 10% in 2017 sparking a "rush to build" ahead of that date.[98]

The American Recovery and Reinvestment Act (ARRA), which was signed into law in early 2009, gave another Federal impetus to the utility segment by adding $40 billion in loan guarantee authority for renewable energy projects under Section 1705 of the Energy Policy Act to the $51 billion that was previously available under Section 1703 for a wider range of projects, including nuclear projects.[99] The loan guarantee program "successfully increased innovation and investment in utility-scale PV" and disproportionately benefited large-scale deployment. "Approximately $13 billion in loans, about 80% of all loan guarantees under the program, went to solar investments, primarily generation projects."[100] According to Larry Sherwood, five of the six largest solar PV projects in the country in 2011-2013, which together accounted for almost 1800 MW of installed capacity, received Federal loan guarantees.[101]

Utility segment deployment was highly concentrated in the top five states on an annual basis. (See Figure 22.) In 2013, the year when this trend peaked, the top five states accounted for more than 92% of this segment. In that year as well as 2014, California was the site of over two-thirds of the national total in this segment. All ten of the largest solar PV projects in these years,

[95] Bolinger 2009, *op. cit.*; Sadie Cox, Terri Walters, Sean Esterly, and Sarah Booth, "Solar Power: Policy Overview and Good Practices," National Renewable Energy Laboratory, NREL/TP-6A20-64178, May 2015, p. 12**.**

[96] MIT Energy Initiative, *The Future of Solar Energy* (2015), p. 88, estimates that "only 20 or so institutions" engage in tax equity investing and provides details of some of the deal structures. Jonathan Gardiner, "2015 League Tables," BNEF, p. 13, shows only 11 investors in the tax equity market.

[97] Colin Smith, "The Next Wave of U.S Utility Solar Procurement Beyond the RPS," GTM Research, February 2016, p. 20.

[98] Bolinger and Seel, *op. cit.*, p. 39. The late 2015 rush will be reflected in 2016 installed capacity. Similar rushes also occurred in the final quarter of each year as developers pushed to get projects qualified for the credit within the year.

[99] DOE 2010, *op. cit.*, pp. 80-81.

[100] Cox *et al., op. cit.,* p. 12. This figure may include concentrating solar power as well as PV projects.

[101] Larry Sherwood, *U.S. Solar Market Trends 2013*, Interstate Renewable Energy Council, July 2014, p. 12.

Sherwood notes, provided electricity for California customers, including projects in Nevada and Arizona as well as in California. The Agua Caliente project in Yuma, Arizona, and the Copper Mountain project in Boulder City, Nevada, for example, brought more than 600 MW on-line between 2012 and 2014, which was sold to California utilities. California's RPS, which was raised to 33% by 2020 in 2006, and its huge electricity market, were the primary drivers of this growth.[102]

Utility	2010	2011	2012	2013	2014	2015	2010-2015
California	22	233	542	1,918	2,628	1,858	7201
North Carolina	26	27	121	276	390	1,114	1954
Arizona	9	182	592	290	103	106	1282
Nevada	55	24	191	38	318	206	832
Texas	16	34	36	60	99	165	410
Georgia	-	2	1	86	42	207	338
New Mexico	35	114	15	26	67	28	285
New Jersey	24	52	76	9	77	42	280
Utah	-	-	-	-	-	194	194
Colorado	19	45	34	-	-	82	180
All others	61	71	195	152	198	148	825
Total	267	784	1803	2855	3922	4150	13781
Top 5 % total	60%	79%	85%	92%	90%	86%	85%
CA % total	8%	30%	30%	67%	67%	45%	52%

Figure 22: Utility PV Deployment by State, 2010-2015[103]

RPS's also drove growth of utility-scale deployment in other leading states. About half of the states increased their overall RPS targets in the 2010s, while only two reduced them. More important, 18 states and the District of Columbia included solar carve-outs to their RPS, precipitating a shift in RPS-related capacity additions from wind to solar.[104] As Figure 23 demonstrates, solar has significantly outpaced wind in this respect over the past three years**.** These requirements also added volatility to the market at the state level. After the standard was reached in Colorado and SREC prices crashed in New Jersey, capacity growth dropped precipitously in 2013 in these states, contributing to a drop in national capacity growth outside of California in that year.[105]

[102] Sherwood 2014, *op. cit.*, p. 12; Greentech Media, *U.S. Solar Market Insight – Year in Review, 2014*, Greentech Media, 2015, p. 45.
[103] GTM 2016a, *op. cit.*, p. 46
[104] Galen Barbose, "U.S. Renewables Portfolio Standards, 2016 Annual Status Report," Lawrence Berkeley National Laboratories, April 2016, p. 8.
[105] Greentech Media, *U.S. Solar Market Insight – Year in Review, 2013*, 2014, p. 41 and p. 50; Hart, *op. cit.*

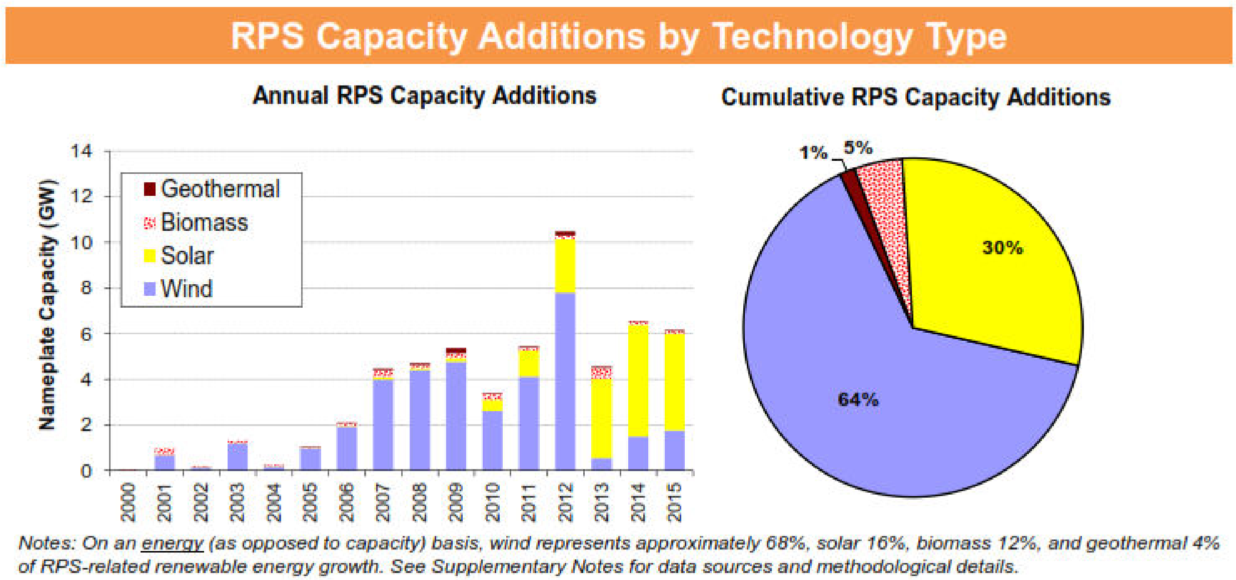

Figure 23: RPS Capacity Additions by Technology Type[106]

A striking new trend in Figure 22 is the inclusion of the southeastern states, with Georgia and Texas joining the top five deployment sites in 2013 and North Carolina rising to second place in 2014. In 2015, North Carolina became the first state other than California to deploy more than 1 GW in a single year. The southeast region has better solar resources than any other region besides the southwest, yet the lack of supportive state policies had inhibited their development.[107]

In the case of North Carolina, a 35% state tax credit and a very generous standard offer to third party developers for qualified facilities under PURPA were key stimuli for deployment in this period. (The surge in the state in 2015 was prompted largely by the impending expiration of the state tax credit as well as the expected expiration of the Federal ITC.[108]) In Georgia, an unrestructured market without an RPS, the Public Service Commission approved the inclusion of solar projects in Georgia Power's integrated resource plan, allowing the firm to recoup investment in PV generation.[109] In Texas, Austin Energy, a municipal utility, helped to jumpstart the growth of solar in the state with its 30 MW Webberville project, which came on-line in 2011; CPS Energy, a municipal utility in San Antonio, was also an early investor.[110]

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[106] Barbose, *op. cit.*, p. 13.
[107] Bolinger and Seel, *op. cit.*, p. 7.
[108] GTM 2016a, *op. cit.*, p. 35; GTM 2014, *op. cit.*, p. 37; Bolinger and Seel, *op. cit.*, p. 30. North Carolina also has an RPS with a modest solar carve-out (including water heating and other solar energy resources in addition to PV) of 0.2% by 2018. The standard offer to QFs under PURPA was an important factor in the growth of Utah's installed capacity as well.
[109] GTM 2014, *op.cit.*, p. 47
[110] Chris Whitmore, "Austin Energy Inaugurates 30 MW Webberville Solar Plant," *PV Tech*, January 9, 2012 (http://www.pv-tech.org/news/austin_energy_inaugurates_30mw_webberville_solar_plant).

There is something of a chicken-and-egg relationship between the policies in these states and the declining cost of utility-scale PV in the past six years. Cost declines have reduced the risk of ratepayer backlash against regulatory commissions, regulated utilities, and municipal utilities, making it much easier for them to support investment in PV. Relatively aggressive RPS targets have become much easier and cheaper to hit, protecting legislators who support them.

With the Federal ITC in place for the next few years, DOE and private analysts expect PV projects to become cost-competitive in the utility segment in the solar resource-rich southeast and southwest without additional state incentives. "[U]tility PV is now an economically competitive resource that can be used to meet utilities' peak power needs, and second, it serves as fixed price hedge against natural-gas price uncertainty." "[A]t these low price levels, solar can compete head on with wind power in terms of both price and generation profile."[111]

Non-Residential Segment Deployment
As we noted earlier, the non-residential segment, which was the largest segment of the national PV market during the 2000s, slowed down so much in the 2010s that by 2015, it was the smallest segment, accounting for just 14% of the market that year. The segment actually shrank by 3% in 2014 and 4% in 2015. (See Figures 9, 19, and 20.) This was the case even though unit costs for non-residential systems were substantially less on average than those for residential systems. (See Figure 21.)

On the other hand, unit costs for non-residential systems were higher than those for utility systems, and it is possible that the latter segment, which did not exist for most of the 2000s, substituted directly for the former in the 2010s, rendering these categories less meaningful than they had previously been. Utility-scale PV systems may be built with the knowledge that much or all of the power generated will be purchased by non-residential customers, such as industrial, commercial, government, and school facilities. However, because the power passes through the utility first, rather than being taken directly by the customer, such systems are counted in the utility segment in this paper. (See Section 2 for a discussion of segment definitions.)

Federal policy may also have contributed inadvertently to this shift. In order to take full advantage of the ITC, tax equity investors often had to structure complex, customized deals. They therefore had strong incentives to prefer large systems with large, sophisticated partners in order to minimize transaction costs.[112] Once the utility segment was opened by the 2008 revisions to the ITC, it became more desirable in this regard than the non-residential segment. GTM Research put it this way in its year-in-review of 2014: "Financing and developing small to mid-sized projects has often proven to be prohibitively difficult."[113]

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[111] Smith, *op. cit.*, quote from p. 5; Bolinger and Seel, *op. cit.*, quote from p. 34; GTM Research 2016a, *op. cit.*, p. 35; David Feldman, David Boff, and Robert Margolis, "Q3/Q4 2015 Solar Industry Update," U.S. DOE Sunshot, January 19, 2016, p. 35; Barbose 2016, *op. cit.*, p. 14.
[112] MIT Energy Initiative, *op. cit.*, pp. 88-89, describes three types of deal structures, "partnership or partnership flip, sale-leaseback, and inverted lease."
[113] Greentech Media, 2015, p. 35. Interestingly, the same phrase appears in Greentech Media 2016a, p. 27.

This bias was softened in the first half of the 2010-2015 period (during which the non-residential segment continued to grow rapidly, as indicated in figures 9 and 20), by the availability under ARRA section 1603 of grants in lieu of the investment tax credit for PV systems.[114] The program, which was initially scheduled to conclude in 2010 but was extended for two years, was available for systems on which construction began in 2009-2011 and which became operational by the end of 2012. The Treasury Department reports that the program supported 7814 MW of non-residential PV capacity.[115] Non-profit and government customers could take advantage of the program indirectly through PPAs with private developers. In addition, the bill that extended the ITC in 2008 and ARRA together provided $5.5 billion to the Federal Buildings Fund for green building improvements, including PV systems.[116]

These factors help us to understand the deceleration of non-residential deployment over time. Figure 24, which summarizes deployment in all of the states that reached the top five for this segment in any year in the period, describes the pattern across space as well as time. This segment was not quite as concentrated as the other segments, with the top five states accounting for 70-75% of the national total each year. California, while still the leading state in every year but 2011, held a much smaller share of this segment, about 30%, than the utility and residential segments, where it made up about 50%. Individual large projects, such as Apple's 40 MW of solar PV at its North Carolina data center, explain some of the variation at the state level.[117]

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[114] Sherwood 2014, *op. cit.*, p. 16.

[115] U.S. Department of Treasury, "Payments for Specified Energy Property in Lieu of Tax Credits Under the American Recovery and Reinvestment Act of 2009, FREQUENTLY ASKED QUESTIONS AND ANSWERS," n.d.; U.S. Department of Treasury, "Overview and Status Update of Section 1603 Program," May 5, 2016, p. 3. Both documents are available at https://www.treasury.gov/initiatives/recovery/Pages/1603.aspx . The reader will note that the total non-residential installed capacity on figure 24 is 5435 MW. The Treasury defines only residential and non-residential segments and uses size to differentiate them. Their figure may therefore include some systems that IREC/GTM/SEIA classify in the utility segment; in addition, it may include some capacity that came into service in 2009.

[116] DOE 2010, *op. cit.*, p. 83. Bolinger, 2009, *op. cit.*, p. 47, hailed the PPA as a "revolutionary" advance for non-residential system financing, but he apparently underestimated the difficulty of arranging such financing and the appeal of utility-scale systems.

[117] Sherwood 2014, *op. cit.*, p. 16. GTM 2015, *op. cit.*, p. 36, characterizes these projects as "arbitrary spikes from corporate entities with both large loads and in-state tax liabilities."

Non-Residential	2010	2011	2012	2013	2014	2015	2010-2015
California	90	216	307	293	307	398	1611
New Jersey	89	226	300	189	102	48	954
Massachusetts	14	23	108	171	230	145	691
Arizona	22	76	64	58	50	19	289
New York	10	15	34	42	49	67	217
Pennsylvania	32	70	30	28	8	9	177
Maryland	5	16	41	20	37	45	164
Colorado	16	33	24	28	26	21	148
North Carolina	4	26	2	57	3	11	103
All others	57	133	167	224	249	251	1081
Total	339	834	1077	1110	1061	1014	5435
Top 5 % total	73%	74%	76%	69%	70%	69%	69%
CA % total	27%	26%	29%	26%	29%	39%	30%

Figure 24: Non-Residential PV Deployment by State, 2010-2015[118]

State policies, many of which provided subsidies and other incentives that were capped within or limited to specific use or size categories, provide deeper insights into the spatial pattern. "Very few non-residential PV systems have been installed without the aid of state-level incentives."[119] Figure 25 shows the variation in 2014 across five of the largest states between private customers and public/non-profit customers within the non-residential segment, which reflects the variation in the design of state policies.

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[118] GTM 2016a, *op. cit.*, p. 45. Totals vary slightly from figure 20 due to rounding error.
[119] Bolinger 2009, *op. cit.*, p. 34.

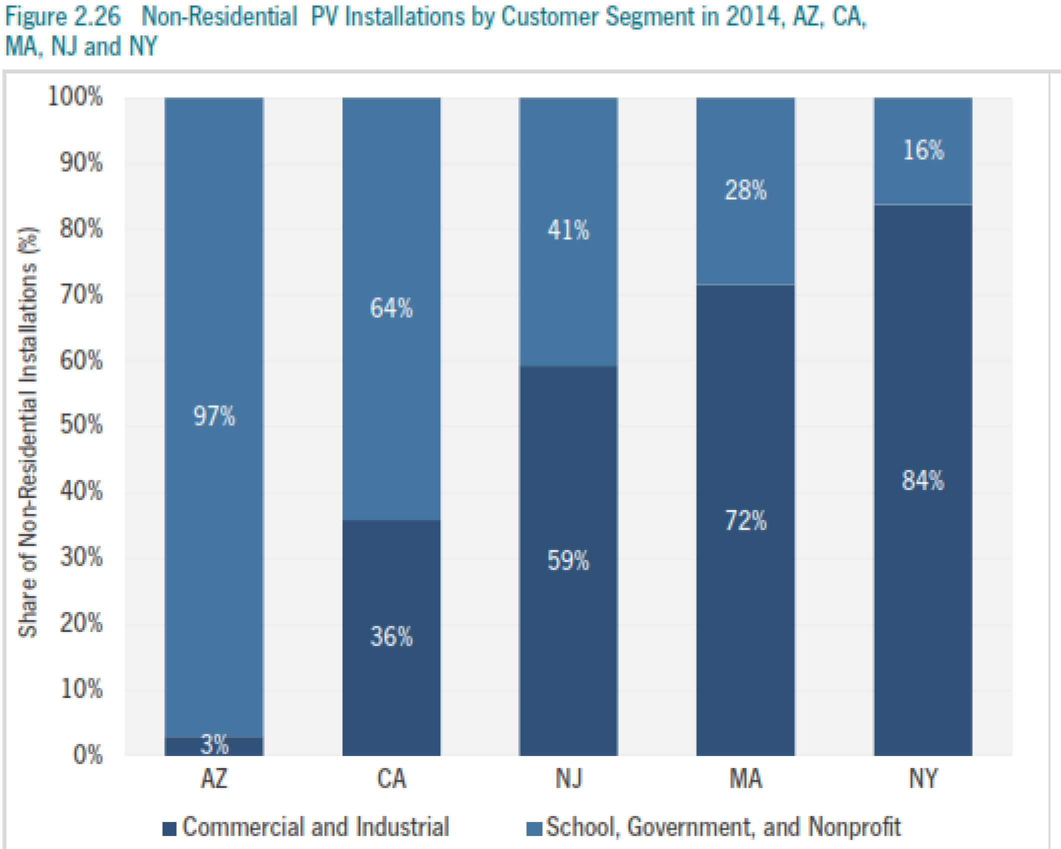

Figure 25: Non-Residential PV Installations by Customer Segment in 2014: AZ, CA, MA, NJ, and NY[120]

The California Solar Initiative, for example, provided performance-based incentives at different rates to taxable and tax-exempt non-residential system owners. As installed capacity within the program grew, the incentive was stepped down and finally eliminated.[121] The incentive was used by most system owners through 2014. As part of a transition away from these incentives, the state encouraged utilities to offer a new tariff (Option R) for non-residential customers that included time of use rates, which roughly doubled the electricity bill savings for new solar PV installations compared to the old tariff.[122] This measure seems to have revived the non-residential segment in 2015, which had stalled in 2013-2014.

The patterns in other states were even more volatile, due to more poorly-designed programs and less consistent policy support. For example, New Jersey, Massachusetts, and Arizona, which together comprised more than 35% of installed capacity in this period, all experienced at least

[120] Greentech Media 2015, *op. cit.*, p. 38.
[121] Bolinger 2009, *op. cit.*, p. 34.
[122] SEIA, "CPUC Adopts 'Solar-Friendly' Rate for Commercial, Industrial Customers," December 18, 2014 (http://www.seia.org/news/cpuc-adopts-solar-friendly-rate-commercial-industrial-customers); Greentech Media 2015, p. 39; Greentech Media 2016a, p. 31.

one annual drop of a third to a half within this segment between 2013 and 2015. In New Jersey and Massachusetts, very low SREC prices discouraged non-residential investment. In Arizona, the state government abruptly cut support for both public and private sector non-residential solar programs as well as adjusting its rate design to make solar investments less attractive.[123]

Unlike the utility segment, the non-residential segment is not yet prepared to thrive without state policies that provide direct or indirect subsidies beyond the Federal ITC. It is admittedly a grab bag of diverse customers. Some large industrial facilities may be as well-positioned as utilities to benefit from low unit costs, and some may seek to go "green" for marketing reasons even at a higher cost. On the other hand, government agencies and schools may be more dependent on the Federal and state fiscal environment and on procurement and facilities management regulations than they are on state solar policies. A more nuanced segmentation as well as more detailed analyses of such factors would provide new insights into the deployment process in this part of the solar PV market.

Residential Segment Deployment

Figure 20 above shows that the residential segment at the national level grew about the same amount in absolute terms (just over 5 GW) as the non-residential segment in the 2010s, but from a lower base and at a steadier pace. The slowest growth between 2012 and 2015 was 59% in 2014 and the highest was 66% in 2015. Neither the housing crash associated with the recession, nor the slowdown in residential PV unit costs in 2014 suggested in figure 21, seem to have impacted it very much. [124] The lifting of the $2000 cap for residential systems under the Federal ITC when it was extended in 2008 provided a baseline policy incentive for systems nationwide through 2015.[125]

California was the leading state in this segment every year from 2010 to 2015, always accounting for at least 40% of the national residential PV market and peaking with a share of over 50% in 2013. (See figure 26.) Arizona also ranked among top five states in installed capacity growth each year, and Hawaii appeared in this group during four out of the six years. But these rankings were not determined solely by the quality of each state's solar resource or the availability of suburban roof space. Cloudy, densely-populated New Jersey and Massachusetts, for instance, each appeared at least twice among the top five states, while sunny, sprawling Florida and New Mexico did not appear at all. This observation, along with the concentration of growth in a small number of states, with the top five accounting for 70-80% annually, points to the importance of state policies in shaping this segment, like the others.

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[123] Greentech Media 2014, p. 34; Greentech Media 2016a, pp. 32-33.

[124] The slowest growth in the entire period was 24% in 2011, which might be attributed to the recession and housing crash, except that in 2009 the segment grew by over 100% and in 2010, by roughly 60%. (See figure 10 along with figure 20.) Barbose and Darghouth, *op. cit.*, do not show a slowdown in price declines through 2014.

[125] The recent extension of the residential ITC includes stepdowns to 26% in 2019 and 22% in 2021 before expiring in 2023.

Residential	2010	2011	2012	2013	2014	2015	2010-2015
California	104	128	196	410	615	1,011	2464
Arizona	32	32	62	73	94	110	403
New York	12	8	15	27	89	163	314
Hawaii	8	21	57	83	61	65	295
New Jersey	20	35	43	38	60	91	287
Massachusetts	2	5	15	30	67	141	260
Colorado	19	14	18	28	42	40	161
Nevada	1	1	0	1	12	95	110
Pennsylvania	14	17	7	10	2	4	54
All 0thers	31	47	77	94	221	377	847
Total	243	308	490	794	1263	2097	5195
Top 5 % total	78%	76%	77%	80%	73%	69%	72%
CA % total	43%	42%	40%	52%	49%	48%	47%

Figure 26: Residential PV Deployment by State, 2010-2015[126]

State RPS's played a vital early role in spurring the residential market, but, as RPS targets have risen, utility systems have become far more important for meeting them. Given the gap in unit costs illustrated in figure 21, subsidizing relatively few large projects is far more fiscally and administratively sustainable than subsidizing a very large number of small ones. Nonetheless, the residential segment remains important to the political sustainability of the RPS, as it helps to mobilize a supportive constituency behind it.[127]

In order to sustain the residential segment, states must provide adequate incentives as well as compel interconnection and net metering.[128] Risk, along with cost, continue to be deterrents to residential purchasers.[129] The California Solar Initiative, described in the non-residential segment section above, for example, included parallel provisions for residential customers. As the state transitioned away from direct incentives under CSI in 2012-2014, favorable net metering arrangements remained crucial for residential installations to be financially viable.[130]

Arizona also made the transition away from direct incentives, but most other leading states, including Colorado, Massachusetts, New Jersey, and New York, continued to rely on them.[131] Solar-friendly policies continued to be vulnerable to changes in the political environment at the state level. The collapse of the Nevada residential market when net metering was shifted from retail to wholesale rates in late 2015 illustrates the point. "Nevada's rapid ascendency to being a

[126] GTM 2016a, *op. cit.*, p. 44. Totals vary slightly from figure 20 due to rounding.
[127] Hart, *op. cit.* sketches a version of this narrative in New Jersey.
[128] Sherwood 2014, p. 14, noted that 95% of distributed PV generation (residential and non-residential) across the country was net metered.
[129] Christoph Bauner and Christine L. Crago, "Adoption of Residential Solar Power Under Uncertainty: Implications for Renewable Energy Incentives," *Energy Policy* 86:27-35 (2015).
[130] Barbose and Darghouth, *op. cit.,* p. 19; GTM 2016a, p. 19.
[131] GTM 2014, *op. cit.*, pp. 29-49; GTM 2015, *op. cit.*, pp. 17-31; GTM 2016, *op. cit.*, pp. 19-20.

top ten state market in 2015 will be short-lived due to this decision...we expect 93% less residential solar installations in Nevada in 2016 than previously projected."[132] However, in California and other states in which major residential solar programs existed, with the exception of Hawaii, efforts to revise policies had not resulted in significant change as of the end of 2015.[133]

Another factor in the calculus of potential residential customers for PV systems is the retail rate for electricity, which is in part a result of state policies. (In states with vertically integrated utilities, this price is determined directly by public utility commissions; in others, wholesale power markets influence them as well.) As PV costs have declined and electricity rates have risen, the gap between the levelized cost of electricity (LCOE) that PV systems generate and the alternative of paying the retail rate has narrowed considerably. When the policies mentioned above (such as net metering) are included in the calculation, the gap has begun to disappear in states with high retail rates.[134] Figure 27 displays the states according to the degree to which "grid parity" had been reached in 2016; the top five states on this figure – California, Massachusetts, Hawaii, New Jersey, and Arizona -- are five of the top six residential markets in figure 26.

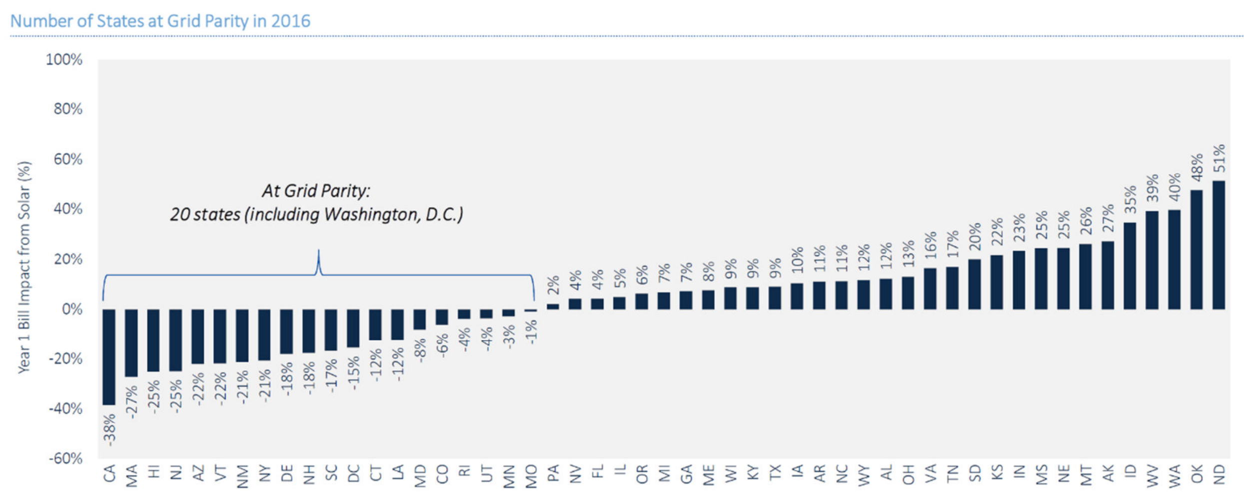

Figure 27: Number of States at Grid Parity in 2016[135]

Financial innovation helped to drive the residential segment in the 2010s as well. New business models emerged that simplified the buying process and provided a much wider variety of choices to purchasers than had been available in the past. Buyers, if they so chose, could limit their risk

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[132] GTM 2016a, *op. cit.*, p. 19.
[133] The Hawaiian case is very complex, due to its unique geographical setting, outstanding solar resources, and very high penetration of PV, which in some places exceeds the daytime maximum load.
[134] In addition to the reference from which figure 27 is drawn, see Severin Borenstein, "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives, and Rebates," Energy Institute at Haas, University of California – Berkeley, July 2015.
[135] Cory Honeyman, "U.S. Residential Solar Economic Outlook: Grid Parity, Rate Design and Net Metering Risk," GTM Research, February 2016, p. 22.

and upfront cost by leasing a system and agreeing to a PPA, for example. The lessors of such systems were then in a position to raise capital on a large scale, utilizing the tax equity market.[136] By 2014, homeowners could also take out "solar loans" to finance PV systems and, in some places, borrow from local governments under "property-assessed clean energy" (PACE) programs. Vendors were also instrumental in diffusing awareness and information into the market through advertising on a larger scale than in the past.[137]

Figure 28 shows the rapid rise of third party ownership (TPO) in the residential segment in several of the largest state markets. By 2012, nearly 90% of new residential systems were being financed through a TPO agreement in Arizona and 70% in California. The trend has leveled off recently as solar loans and PACE gained traction and lower costs allowed more buyers to pay cash for their systems.[138]

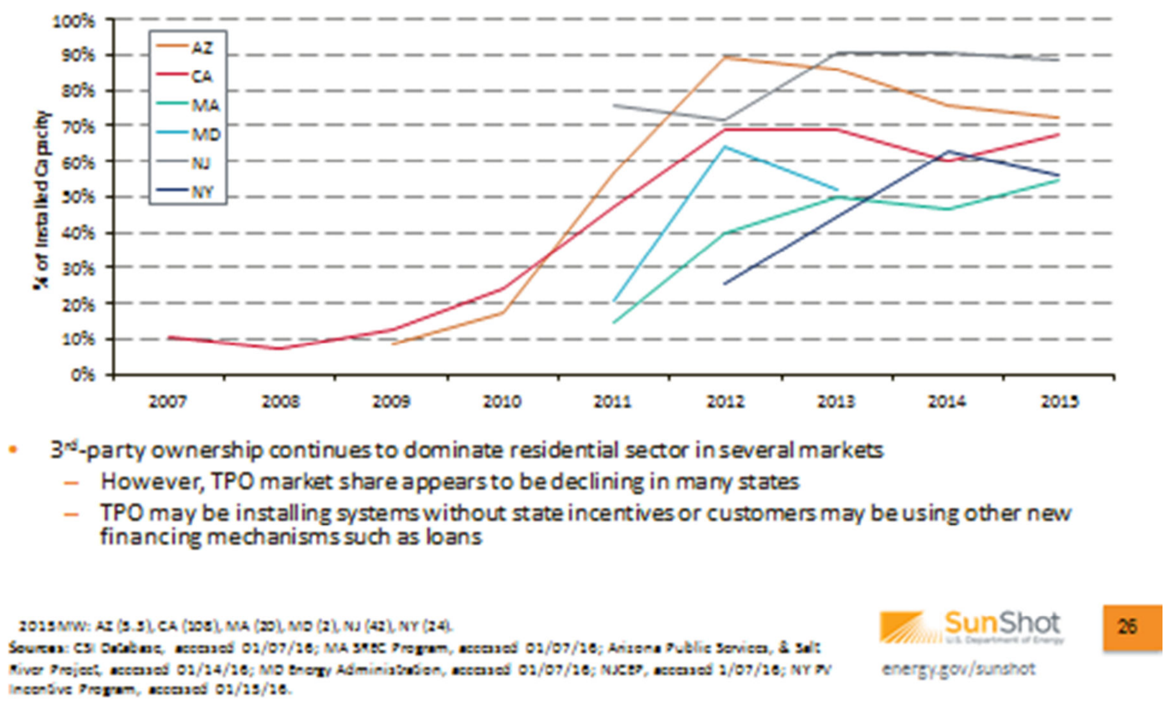

Figure 28: Residential Third Party System Ownership in Major State Markets[139]

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[136] Nicole Litvak, *U.S. Residential Solar Financing, 2014-2018*, GTM Research, June 2014, provides a detailed rundown of various business models, which have continued to evolve since this piece was written. Business Council for Sustainable Energy and Bloomberg New Energy Finance, *op. cit.*, p. 87, states "In 2015, tax equity funds [for US third-party PV financing] totaled an estimated $1.9bn, dominated by SolarCity, Sunrun, SunEdison and Vivint, each of which raised $100m or more. SolarCity raised the most at an estimated $700m in 2015 alone."

[137] Ben Sigrin, Jacquelyn Pless, and Easan Drury, Diffusion Into New Markets: Evolving Customer Segments in the Solar Photovoltaics Market" *Environmental Research Letters* 10 (2015) 084001.

[138] Litvak *op. cit.*; GTM 2016a, *op. cit.*, p. 17.

[139] Feldman, Boff, and Margolis, *op. cit.*, p. 26.

Financial innovation notwithstanding, the cost, risk, and unfamiliarity of residential PV systems mean that purchasers tend to be more affluent, better educated, older, and plan to live in their homes for longer than other members of the population.[140] Such demographic factors are better predictors of adoption at the household level than political preferences, such as environmental values.[141] In addition, peer effects, such as observation of and contact with neighbors who own systems, are also associated with higher levels of adoption within communities. "[T]he combination of passive and active peer effects has the potential to create positive feedback loops as new adopters are added to the existing base, thereby dramatically increasing PV adoption."[142] The presence of solar community organizations seems to encourage adoption as well.[143]

The residential segment, like the non-residential segment, remains heavily dependent on state as well as Federal policies. In sunny places with well-established markets and extensive third-party ownership, notably California, the state has been able to eliminate direct incentives for PV adoption without hampering deployment growth, but the market remains sensitive to rate structures and net metering and interconnection rules. Other states, less well-endowed and less well-developed, must not only attend to these aspects of market design, but also take more assertive steps to subsidize costs, encourage vendor entry, and support financial innovation if their rooftops are to become the sites of large-scale PV deployment.

Foundations and Pillars

PV deployment in the U.S. in the 2010s built on the momentum established in the 2000s. The national foundations of the growth of installed capacity from about 1 GW at the beginning of 2010 to more than 25 GW at the end of 2015 were declining costs and Federal tax policy. These foundations had, by 2015, allowed the utility segment, in which costs are lowest, to begin to compete on an economic basis with alternative sources in locations with high insolation. Policy-makers in some states built on these foundations by erecting segment-specific pillars that fostered growth in the non-residential and residential markets, albeit on a significantly smaller aggregate scale than in the utility segment.

6. Conclusion: No Inflection in Sight

The first operational PV systems were invented in the U.S. As we have described in this paper, the U.S. led the development and diffusion of this technology in its early days, first in the space program and then in terrestrial applications, including both on- and off-grid power generation. With the decline of oil prices and the waning of the energy crisis, leadership moved elsewhere in the world and U.S. deployment flagged. A new energy crisis and growing concern about climate change triggered a revival after 2000, and this revival has been sustained through the present.

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140 Borenstein, *op. cit.*, Sigrin *et al.*, *op. cit.*

141 Eason Drury, *et al.* The Transformation of Southern California's Residential Photovoltaics Market through Third-Party Ownership," *Energy Policy* 42: 681-690 (2012).

142 Varun Rai and Scott A. Robinson, Effective Information Channels for Reducing Costs of Environmentally-Friendly Technologies: Evidence from Residential PV Markets," *Environmental Research Letters* 8 (2013) 014044, p. 7.

143 Daniel Noll, Colleen Dawes, and Varun Rai, Solar Community Organizations and Active Peer Effects in the Adoption of Residential PV," *Energy Policy* 67:330-343 (2014).

The tremendous growth of the PV market in the U.S. since 2000 may reasonably provoke the question of whether some leveling off might be anticipated soon, particularly in light of the slowing growth in figure 15. Diffusion curves are typically S-shaped. At some point, the demand of mainstream buyers is saturated, while potential "late adopters" lack resources, require more expensive versions of the technology being diffused, or resist adoption for non-economic reasons, slowing the pace of adoption.[144]

To put the question another way: are we nearing the upper inflection point on the PV diffusion curve? We do not think so. The U.S. electricity market is enormous. Even though solar PV made up almost 30% of all additions to electrical generating capacity in the U.S. over the past three years, it still comprises only 2% of total capacity.[145] Intermittency and limits to insolation undoubtedly limit its potential below 100% of the latter at present, but penetration far higher than the current level is technologically feasible, having already been achieved in many locations.

The foundations for continuing to move up the curve, declining costs and generous Federal tax policy, seem secure for the short- and medium-term. Global PV markets have continued to grow, providing additional experience for module makers to move down the curve in figure 17. In fact, the U.S. share of global installed capacity has grown only from about 8% in 2008 (see figure 5) to 14% in 2016 (see figure 29), meaning that the rest of the world has not been far behind the American pace.

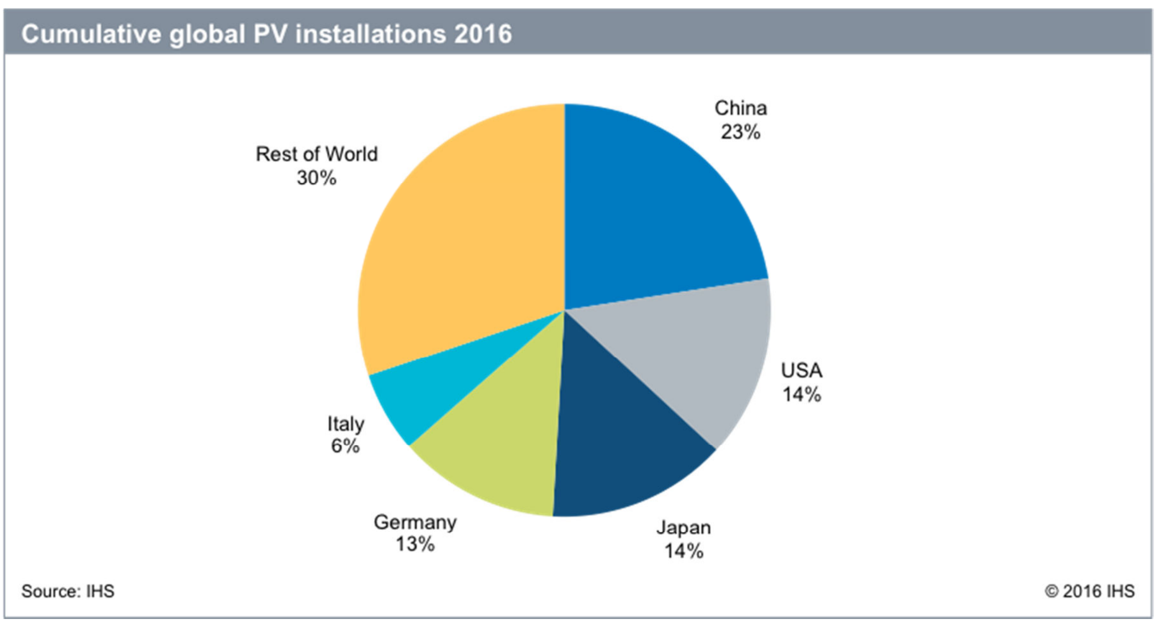

Figure 29: Cumulative Global PV Installations, 2016[146]

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[144] Everett M. Rogers, *Diffusion of Innovations* 5th ed. (Free Press, 2003).
[145] GTM Research, *U.S. Solar Market Insight Q2 2016* (GTM 2016b), p. 6 and p. 8.
[146] IHS, Inc., "As European Solar Installations Slow, China, US and Japan Lead Global Installed PV Capacity in 2016, IHS Says," February 29, 2016 (http://press.ihs.com/press-release/european-solar-installations-slow-china-us-

Balance of system costs should also continue to decline as installers, financiers, consumers, and communities in the U.S. gain experience and continue to innovate. These costs are lower in comparable international markets, such as Germany and Australia. Lawrence Berkeley National Laboratory's Galen Barbose and Naïm Darghouth therefore conclude that "Notwithstanding the significant installed price reductions that have already occurred in the United States, international experience suggests that greater near-term reductions are possible."[147]

The ITC has been extended until 2023. Congress and the President could, of course, reduce or eliminate it before that time. Doing so would require overcoming substantial inertia as well as a large and growing set of constituencies that are benefiting or could benefit from the policy. The most likely scenarios for such a change might be a large-scale simplification of the tax code, like that enacted in 1986, or a general fiscal tightening, as some deficit hawks have advocated. While predictions about American politics are hazardous, there is little in the past record to suggest that such scenarios will come to pass. The Clean Power Plan, assuming it comes into force, may provide another foundation for the national market later in this decade.

The biggest state policy pillars that build on these national foundations are California's, across all three segments. California has shown a consistent commitment to expanding PV capacity and has creatively overcome a series of obstacles and challenges in the past decade and a half. In other states, like Nevada and New Jersey, the commitment has been inconsistent. However, the number of states enacting solar policies has grown over time, with striking results in some cases, like North Carolina joining California in the gigawatt club last year. State-level imitation and learning is likely to continue, with new pillars more than taking the place of those that crack. In particular, policy-makers seem likely to seize low or no cost opportunities for utility segment growth in the southeast and southwest, where PV with Federal subsidies alone is economically viable and some states have virtually no installed capacity yet. GTM anticipates explosive growth in 2016, for instance, in Florida, Georgia, South Carolina, Texas and Utah.[148]

Over the long-term, it may be possible to extend the steeply sloped portion of the diffusion curve and delay reaching the inflection point through continued innovation. Low-cost storage, the use of new materials, and building integration are among the areas in which technological progress could make a big difference.[149] Innovation in utility business models through creative market design and rate-making processes will be essential, too.

The future of PV is bright.

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and-japan-lead-global-installed-pv-capacity). The data source for this figure is different from that for figure 5, so the comparison may be slightly imperfect.

[147] Barbose and Darghouth, *op. cit.*, p. 23.

[148] GTM 2016b, p. 45. Alabama, Arkansas, Missippi, and Oklahoma do no yet appear in GTM's state tables.

[149] MIT Energy Initiative, *op. cit.*, chapter 10.