Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1
Q3 Q2 Q1 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q2 Q3 Q4 Q4 Q3 Q2 Q1 Q1 Q2 Q3 Q4

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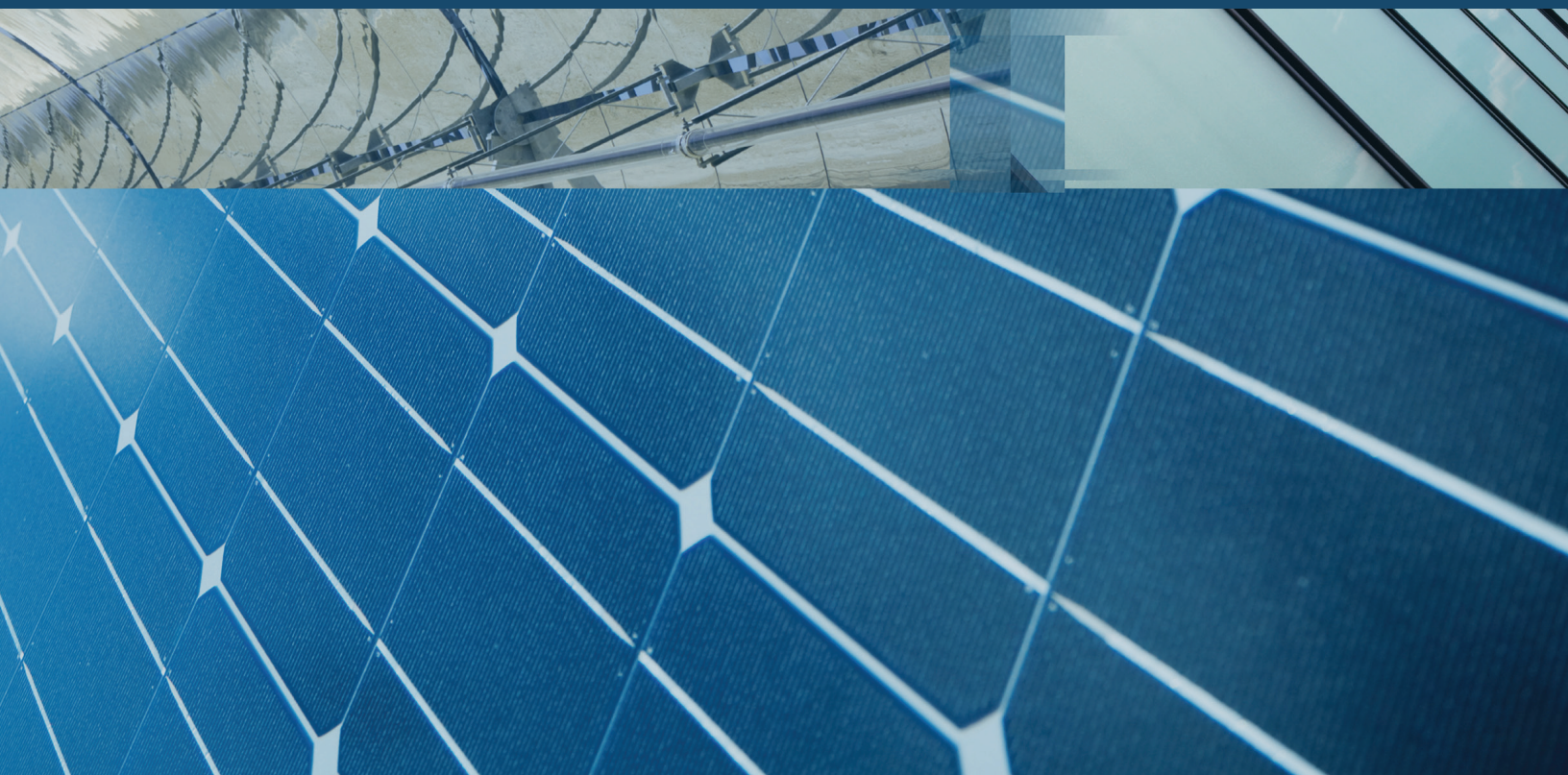
U.S. SOLAR MARKET INSIGHT

REPORT | Q2 2014 | FULL REPORT



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1. Introduction

The U.S. Solar market had another strong quarter in Q2 2014. Photovoltaic (PV) installations reached 1,133 MW in Q2, up 21% over the same quarter in 2013. As has been the case for the last two years, the utility PV market drove the majority of this growth, accounting for 55% of capacity installed in Q2 2014. Across the distributed generation landscape, residential PV resumed its trend of incremental quarterly growth, with more than 240 MW installed for the third straight quarter. Meanwhile, non-residential PV rebounded after adding fewer installations than the residential market in the first quarter of 2014.

Beneath the top-level numbers, the market is complex and always changing. In this report, we highlight a number of important dynamics shaping the market today. Among them:

- **The resurgence of utility PV procurement.** Despite many utilities in the Western U.S. having already met their near-term renewable energy obligations, utility-scale solar project developers have amassed more than 3 gigawatts of new contracts over the past twelve months. Solar's increasing cost-competitiveness, along with a variety of new procurement mechanisms, is fueling the flames of a market that had, until recently, been focused primarily on existing pipeline build-out.
- **Continued net energy metering debates, with potential solutions on the horizon.** Net energy metering remains a crucial point of contention between the solar industry and utilities in more than a dozen states. Thus far, the outcomes of these debates have largely favored the solar industry, but many remain in process. We highlight the minimum bill, recently proposed in Massachusetts and under consideration in a number of other states, as a potential framework for compromise.
- **The residential solar juggernaut continues.** The residential market has seen the most consistent growth of any segment for years, and its momentum shows no signs of slowing. For the first time ever, more than 100 MW came on-line without any state incentive in Q2 2014. However, the residential market has grown increasingly dependent on California, which accounted for more than 50% of installations for the fourth consecutive quarter.
- **The small commercial solar gap.** Within the non-residential market, we focus on the small commercial sector, whose share of installations has been shrinking precipitously over the past few years, even as the share of projects larger than 1 MW has grown. Difficulties in financing, along with other non-scaling costs, have long kept the small commercial sector in check despite its enormous potential. Still, we see some opportunity on the horizon as companies develop mechanisms to build out and finance small commercial portfolios.

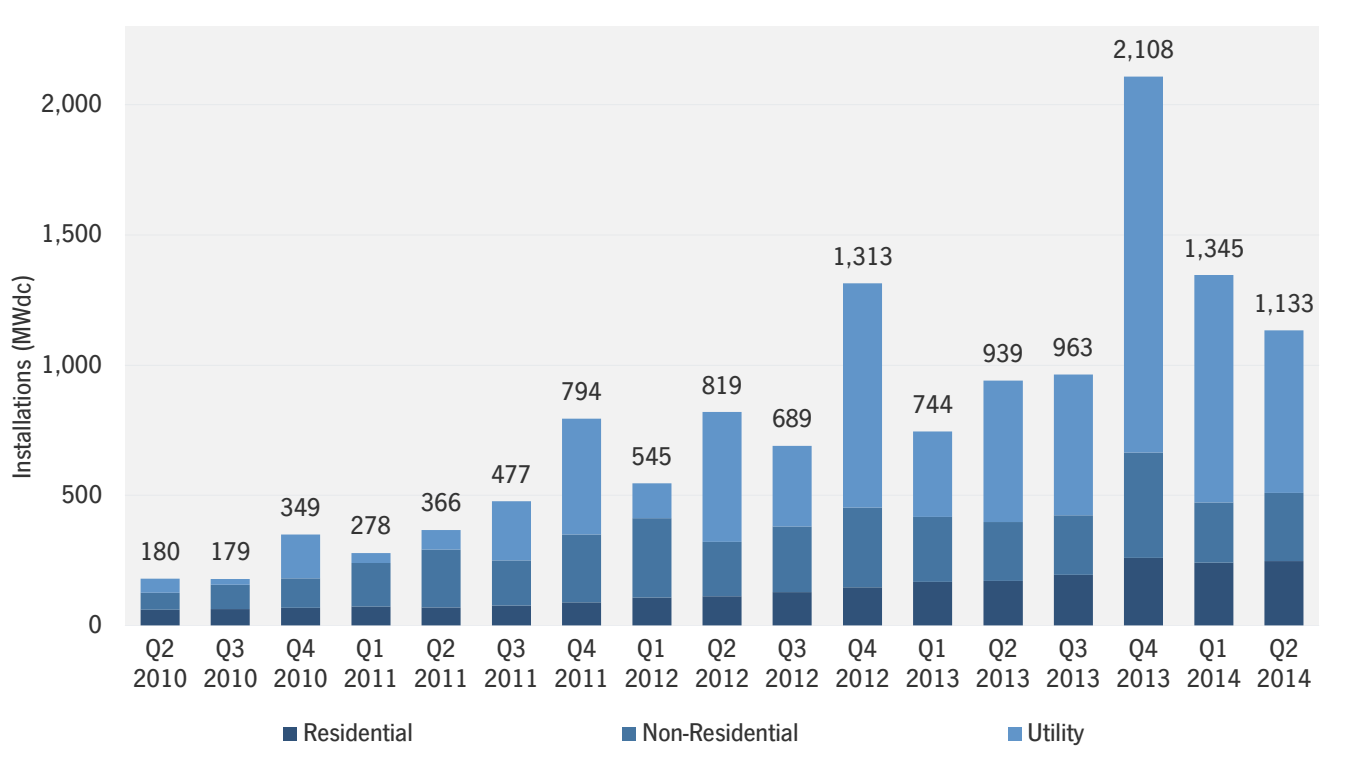
By all accounts, 2014 will be another banner year for solar in the U.S. We forecast that 6,528 MW will be installed this year, up 36% over 2013 and more than 650% over 2010.

2. Photovoltaics

2.1. Installation Overview

The U.S. installed 1,133 MW of solar PV in the second quarter of 2014, down 16% from Q1 2014 but up 21% over Q2 2014. This is the third consecutive quarter in which more than 1 gigawatt (GW) was installed in the U.S., bolstered by the continuing distributed generation (DG) boom, as residential and non-residential installations added more than 500 MW for the second time ever.

Figure 2.1 U.S. PV Installations, Q2 2010-Q2 2014



	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
	2010			2011				2012				2013				2014	
Residential	60	63	67	72	68	75	88	107	111	128	147	168	171	195	260	241	247
Non-Residential	64	94	115	168	224	175	261	305	210	251	305	248	226	228	404	231	261
Utility	55	22	167	38	75	227	445	134	498	310	861	328	543	540	1444	873	625
Total	180	179	349	278	366	477	794	545	819	689	1313	744	939	963	2108	1345	1133

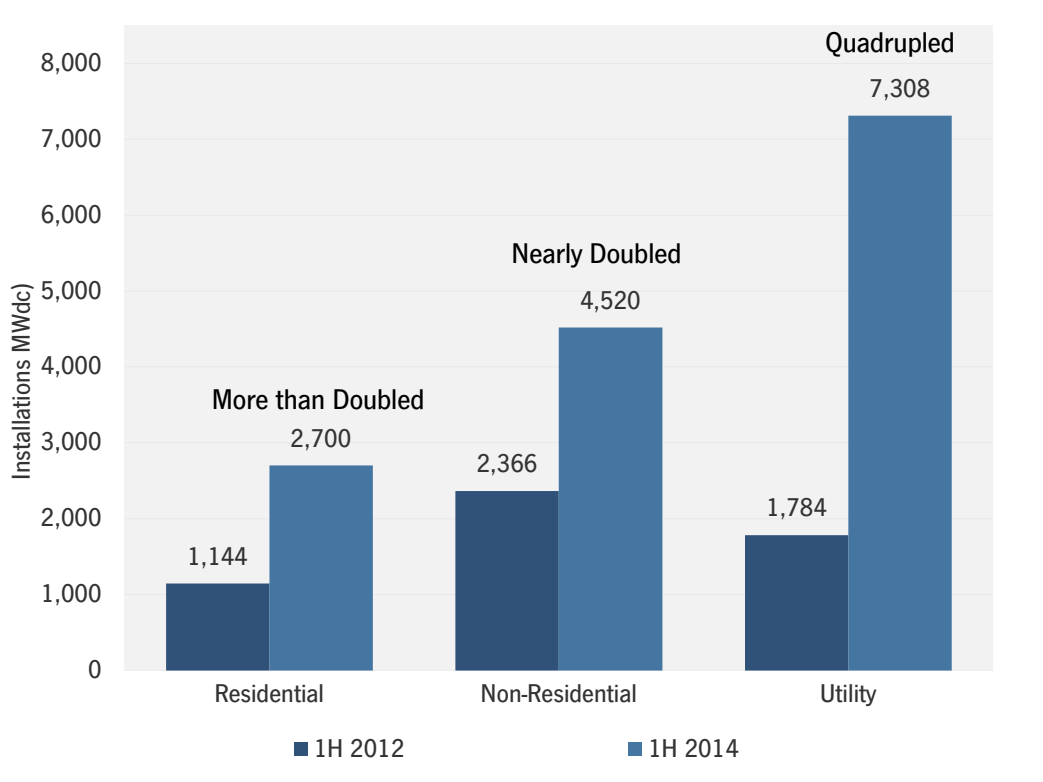
Although the DG market has grown by impressive strides, the primary source of U.S. demand continues to be utility PV. More than 10 gigawatts of utility PV earned PPAs between 2010 and 2012, thanks to a wave of aggressive procurement driven by RPS standards. This contracted pipeline is finally becoming realized, and the

outlook for utility PV remains stronger than ever as contracted capacity continues to outpace capacity brought on-line in primary markets (California and North Carolina) and secondary markets as well (Georgia, Minnesota, Texas, and Utah).

2.2. Is Solar PV Mainstream?

Over the past two years, solar PV has grown light years ahead of where it once stood. Between 1H 2012 and 1H 2014, cumulative residential and non-residential installations both doubled, while cumulative utility PV installations have more than quadrupled.

Figure 2.2 Cumulative U.S. Solar PV Installations by Market Segment, 1H 2012 vs. 1H 2014



But this top-level installation growth is not the only evidence of solar's progress toward becoming increasingly mainstream within the broader energy landscape. Here are three key milestones achieved by the U.S. solar market during the first half of 2014:

- **Gigawatts of PV are now being used for innovative financing strategies.** As of 1H 2014, more than 1.5 GW of solar PV had been used or will be used to finance publicly traded investment vehicles, specifically, YieldCos backed by solar, as well as securitized bonds backed by residential and non-residential PV.
- **Utilities are beginning to launch residential solar installation programs.** Last summer, Arizona's major utility Arizona Public Service attracted industry attention and pushback due to its introduction of net metering fees. Now Arizona Public Service and the state's other investor owned

utility, Tucson Electric Power, are the first utilities in the U.S. to have formally proposed plans to own rooftop solar on residential customers' homes.

- **Procurement of utility-scale solar based on cost-competitiveness.** Over the past twelve months, ten utilities in states without renewable portfolio standards currently in place or ahead of existing RPS requirements have announced plans to procure 3 GW of utility-scale solar due to its economic competitiveness in tandem with or in lieu of natural gas alternatives.

Although the U.S. solar market has more than doubled over the past two years, looking ahead, systemic challenges to growth loom both in the near term (e.g., the recent U.S.-China tariff decision) and further out as well (the federal ITC's scheduled dropdown at the end of 2016). Nevertheless, the first half of 2014 showcased innovative financing strategies, evolving utility business models, and solar's increasing economic competitiveness, all of which offer encouraging signs of the U.S. market's ability to overcome barriers to growth and further push solar PV into the mainstream.

2.3. Residential PV

2.3.1. National-Level Figures

Key figures:

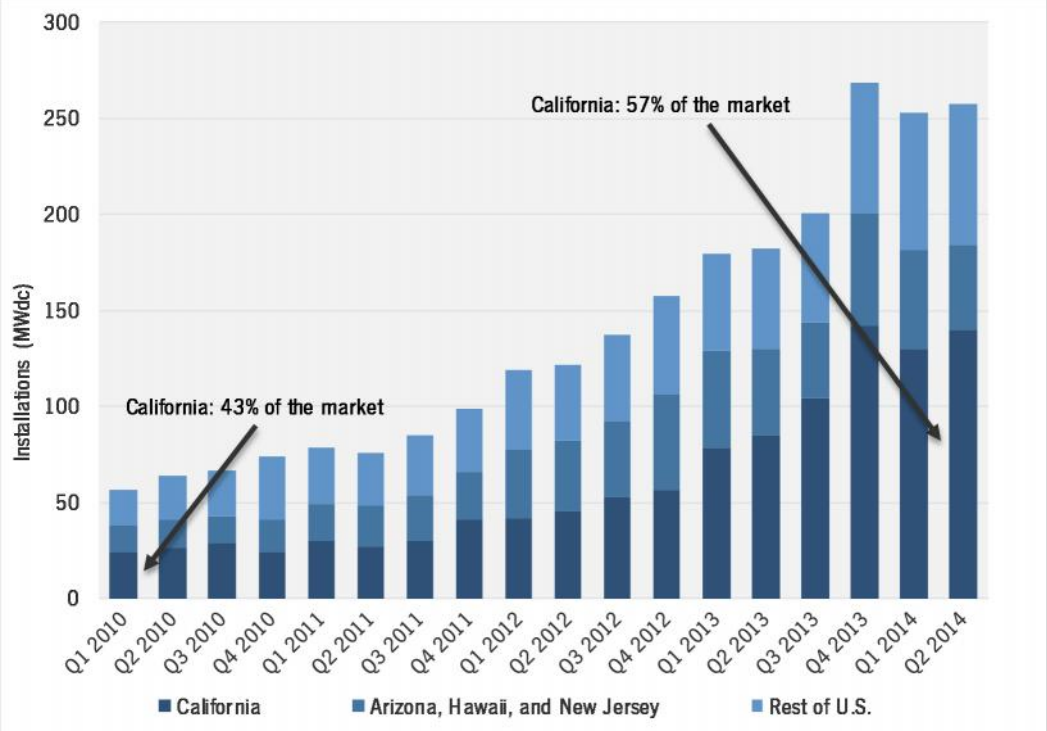
- 247 MW installed in Q2 2014
- Up 45% over Q2 2013
- Up 2% over Q1 2014

In Q2 2014, the residential market resumed its trend of incremental quarterly growth with 247 MW installed. Of the 31 states we track, twenty-two grew on a year-over-year basis, although growth remains increasingly reliant on California, which accounted for a record 57% of national installations in Q2 2014. Third-party-owned (TPO) residential PV systems continue to be an attractive option for many homeowners, driving anywhere from 56% (Massachusetts) to well over 90% (Colorado) of residential installations in mature state markets.

2.3.2. Residential Market Trends

Geographic Distribution of Demand

Figure 2.3 Residential PV Installations, California vs. Next 3 States vs. Rest of U.S., Q1 2010-Q2 2014



Q2 2014 marks the third consecutive quarter in which California accounted for more than 50% of the residential market. Beyond California, the residential market relies on a select number of states where installers and customers can bank on attractive rate design, decreasing reliance on state incentives, high levels of customer awareness, and strong referral bases to achieve scale.

After California, the next three largest residential state markets have consistently been Arizona, Hawaii, and New Jersey. The No. 5 spot has rotated between Colorado, Massachusetts, and New York, with New York reclaiming that position in Q2. The five largest residential state markets in Q2 (California, Arizona, Hawaii, New Jersey, and New York) accounted for 79% of the overall market in that quarter, roughly consistent with their share over the past year.

As residential installers based in the Western U.S. expand eastward and vice versa, installers generally focus their expansion plans on the aforementioned seven states rather than adopting a more geographically diversified approach. On one hand, the residential market has clearly benefited from this targeted growth strategy, with the market growing quarter-over-quarter eleven out of the last twelve quarters. But given that all of these states face pending or recently implemented reforms to net metering, the residential market has become disproportionately exposed to regulatory risk.

Mergers and Acquisitions

There has been a flurry of acquisition announcements from residential solar providers over the past year, especially within the past few quarters. The motivation for each of these acquisitions falls within one or more of the following categories:

- **Market Expansion/Consolidation** – While most installers expand to new states organically by opening their own new offices, another, less common strategy is to acquire an existing installer in a new state or states. For example, RGS Energy (formerly Real Goods Solar) entered the Hawaii market via its recently closed acquisition of Elemental Energy, an installer that operates under the name Sunetric. Most recently, electricity retailer Direct Energy entered the solar market by acquiring installer Astrum Solar.
- **Vertical Integration** – In this case, a vertically integrated residential solar company is one that both owns and sells/installs systems. Sunrun and NRG Energy, two firms that previously provided financing and services exclusively through installation partners, each bought one of their partners, REC Solar (residential division) and Roof Diagnostics Solar, respectively. Both companies plan to retain their existing partner networks but will utilize their new internal sales and installation businesses to scale more rapidly.
- **Miscellaneous Cost Reductions** – In a different form of vertical integration, many solar installers and financiers are lowering costs for modules and other equipment, customer acquisition, system design, and financing by acquiring the vendor that provides these products and services (see Figure 2.4 for recent examples).

Figure 2.4 Residential Solar Acquisitions

Type	Acquirer	Acquired
Market Expansion/ Consolidation	RGS Energy	Sunetric
		Syndicated Solar
	Direct Energy	Astrum Solar
Vertical Integration	Sunrun	REC Solar (residential division)
	NRG Energy	Roof Diagnostics Solar
Miscellaneous Cost Reduction	SolarCity	Paramount Solar
		Zep Solar
		Silevo
		Common Assets
	Vivint Solar	Solmetric
	Sunrun	AEE Solar
		SnapNrack
	Solar Universe	Gen110

Retail Rate Parity: Are We There Yet?

With national average installed costs for residential PV systems having fallen 20% compared to two years ago, a number of residential state markets are at or trending near "retail rate parity." This means that a growing number of states are seeing projects pencil out with only net energy metering (NEM), the federal 30% Investment Tax Credit, and in the case of third-party-owned systems, accelerated depreciation.

The extent to which state markets are at retail rate parity depends not only on installation costs, but also on a number of unique utility- and state-level factors, ranging from rate design to solar insolation levels to various ancillary soft costs and property tax treatment. Most notably, installation growth has occurred amidst the declining availability of state-level incentives in California, and this trend is now unfolding in Arizona as well.

Figure 2.5 California Residential Installations, Q2 2012-Q2 2014, CSI/NSHP Funded vs. Non-CSI/NSHP Funded

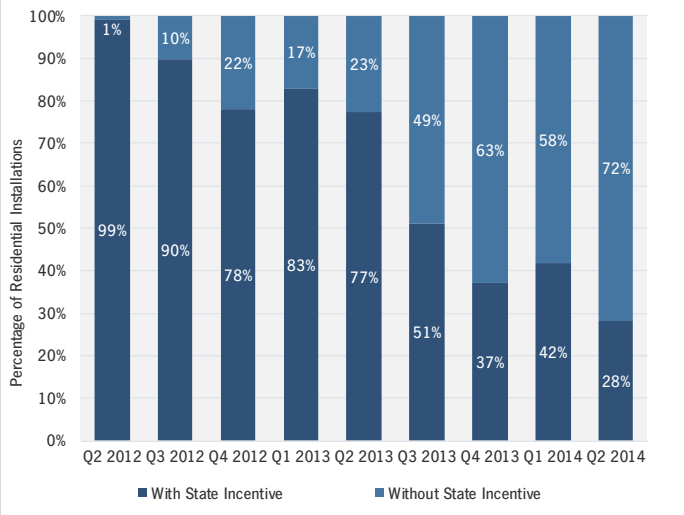
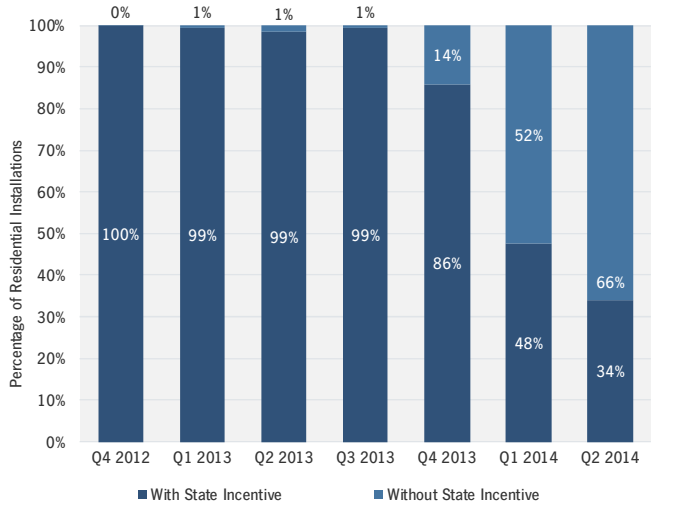


Figure 2.6 Arizona Residential Installations, Q4 2012-Q2 2014, Rebated vs. Non-Rebated

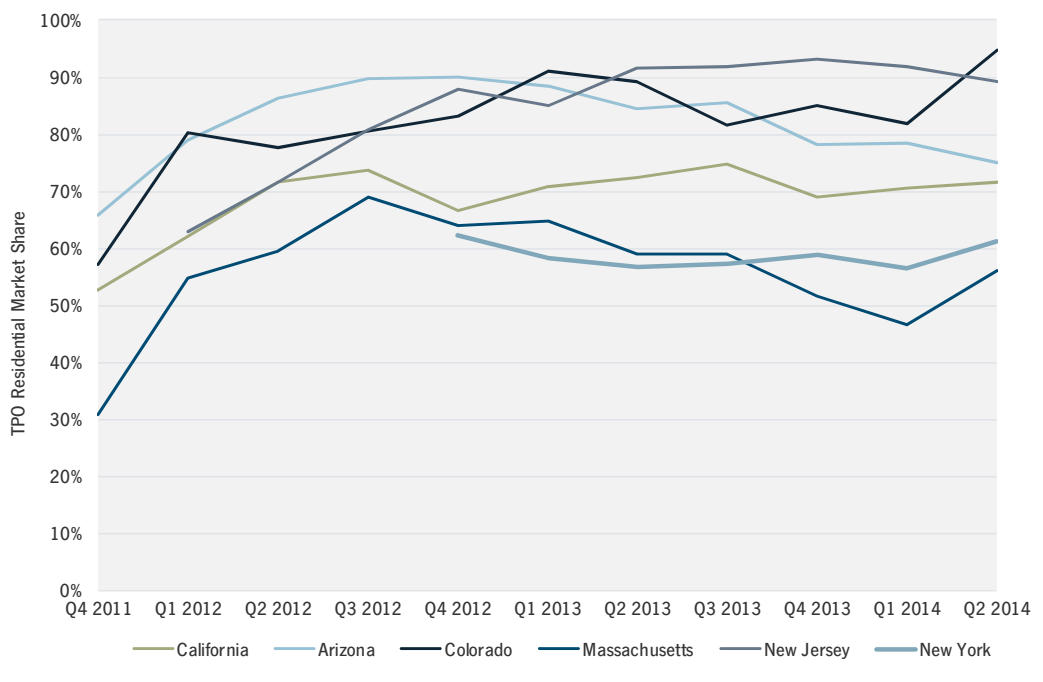


In California, the residential incentives offered by the California Solar Initiative are now fully depleted in PG&E and SCE territories, while SDG&E is at the tail end of its final incentive step, with more than 14 MW awaiting approval for the 1.5 MW worth of incentive funding that remains. Installation trends in PG&E's residential market will serve as a particularly valuable litmus test of the health of California's residential market as a whole, since it was the first utility to deplete CSI rebate funding. In Q2 2014, less than 1% of PG&E's residential solar installations took a state rebate, but installations still significantly outpaced California's overall residential market, with PG&E growing by 79% year-over-year compared to the 45% growth rate statewide.

Meanwhile, Arizona has become the next major state market to see residential installation growth without state incentives following the depletion of upfront residential rebates in APS territory in September 2013 and incentive reductions across other utilities within the state. In Q2 2014, 66% of Arizona's residential installations came on-line without a state incentive.

Trends in Third-Party Ownership

Figure 2.7 Percentage of New Residential Installations Owned by a Third Party in CA, AZ, CO, MA, NJ, and NY, Q4 2011-Q2 2014



	Q4 2011	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
CA	52.6%	62.2%	71.6%	73.7%	66.7%	70.9%	72.5%	74.7%	69.1%	70.5%	71.6%
AZ	65.8%	78.9%	86.3%	89.8%	90.0%	88.5%	84.6%	85.5%	78.2%	78.5%	75.0%
CO	57.1%	80.3%	77.7%	80.6%	83.2%	91.2%	89.1%	81.6%	85.1%	81.8%	94.6%
MA	30.9%	54.8%	59.5%	68.9%	64.0%	64.7%	58.9%	59.1%	51.7%	46.6%	56.2%
NJ		63.1%	71.7%	80.7%	88.0%	85.0%	91.5%	91.8%	93.1%	92.0%	89.3%
NY					62.3%	58.3%	56.7%	57.2%	58.8%	56.6%	61.2%

In most mature state markets, third-party-owned (TPO) residential PV systems continue to be an attractive option for many homeowners. However, Arizona, California, and Massachusetts all experienced gradually declining TPO market share over the past year, as 1) an increasing number of installers have partnered with national and regional banks to provide loans and 2) the cost of solar has come down enough that more customers can afford to pay in cash.

Colorado had a record-high TPO share of almost 95%, an impressive feat in a state where rebates for third-party-owned systems are much lower than those for customer-owned systems. This is largely due to the ability of national lease providers to adjust more quickly to the lumpy incentive cycle. New Jersey also continues to see a consistently high share of third-party-owned systems. Aside from the strong presence of national players that primarily offer TPO solar, the volatility of SREC prices may have contributed to this trend if consumers are becoming less willing to take on this risk.

The addressable residential market is still massive compared to the number of customers who have gone solar, leaving an enormous opportunity for growth, and no single strategy to deliver systems to residential rooftops has yet proven dominant. In the near term, it is expected that TPO PV systems will continue to drive the residential market. Looking forward, however, cash and loan deals could play a larger role as existing players and new entrants to the market react to consumer preferences.

2.3.3. Net Metering Updates

Net energy metering (NEM), the mechanism through which the vast majority of all distributed solar in the U.S. is compensated, remains under debate across more than twenty states. Broadly speaking, utilities have argued that net-energy-metered customers (generally those with on-site solar) benefit from the use of the grid without paying their fair share of costs, while the solar industry has disputed this premise and sought to retain the current net metering paradigm.

The initial wave of NEM disputes largely resulted in favorable outcomes for the solar market. No state has entirely eliminated NEM, nor has any state significantly eroded the value proposition of solar via NEM or rate structure changes. But new disputes regularly emerge, and the landscape of potential outcomes is constantly evolving.

This quarter, we highlight one solution that GTM Research believes merits consideration in many states: the minimum bill. Most net metering debates have revolved primarily around the introduction of a fixed charge to customer bills. Arizona is the primary example of this approach, and the solar industry, understandably, has been opposed to these charges, which can significantly worsen the economics of rooftop solar. But in a recent attempt at compromise legislation between the solar industry and utilities in Massachusetts (H.4185), a minimum bill emerged as an alternative to which both sides agreed.

Although the bill ultimately failed in the final hours of the state legislature's most recent session, we believe that the minimum-bill concept may become more of a focal point in future net metering discussions around the country. In addition to Massachusetts, the idea is under consideration in Louisiana, Kansas, Oklahoma and California.

GTM Research has conducted a theoretical analysis of the effects of the minimum bill on Massachusetts solar customers, the details of which are available in a separate report. We provide some of the key analysis and takeaways here in the following sections.

In order to determine the impact of the minimum bill mechanism on a typical Massachusetts solar customer over the course of a calendar year, we analyzed the impact of a $10 minimum bill on an NStar customer with a 6.3 kW rooftop solar system who has an energy consumption and production profile based on actual data from Genability. We assumed a volumetric retail electricity rate of 17.33 cents per kilowatt-hour and a fixed distribution charge of $7 per month.

Under the current billing mechanism the solar customer would pay $422.77 for the year.

Figure 2.8 Representative Customer Bill – Current Billing Mechanism

	Net Elec. Use (kWh)	Vol. Elec. Bill	NEM Credit	Fixed Dist. Charge	No-Min. Elec. Bill	Excess NEM Credit	NEM Credit Used	Total Elec. Bill
Jan.	427	$74.07	$0.00	$7.00	$81.07	$0.00	$0.00	$81.07
Feb.	266	$46.05	$0.00	$7.00	$53.05	$0.00	$0.00	$53.05
Mar.	-49	$0.00	$8.42	$7.00	-$1.42	$1.42	$0.00	$0.00
Apr.	-159	$0.00	$27.55	$7.00	-$20.55	$20.55	$0.00	$0.00
May	-22	$0.00	$3.74	$7.00	$3.26	$0.00	$3.26	$0.00
Jun.	218	$37.77	$0.00	$7.00	$44.77	$0.00	$18.72	$26.06
Jul.	324	$56.14	$0.00	$7.00	$63.14	$0.00	$0.00	$63.14
Aug.	267	$46.31	$0.00	$7.00	$53.31	$0.00	$0.00	$53.31
Sept.	-75	$0.00	$12.96	$7.00	-$5.96	$5.96	$0.00	$0.00
Oct.	22	$3.81	$0.00	$7.00	$10.81	$0.00	$5.96	$4.85
Nov.	234	$40.61	$0.00	$7.00	$47.61	$0.00	$0.00	$47.61
Dec.	500	$86.68	$0.00	$7.00	$93.68	$0.00	$0.00	$93.68
Total								$422.77

Source: GTM Research and Genability

Under the $10 per month minimum bill mechanism the solar customer would pay $434.77 for the year.

Figure 2.9 Representative Customer Bill - $10/Month Minimum Bill Scenario

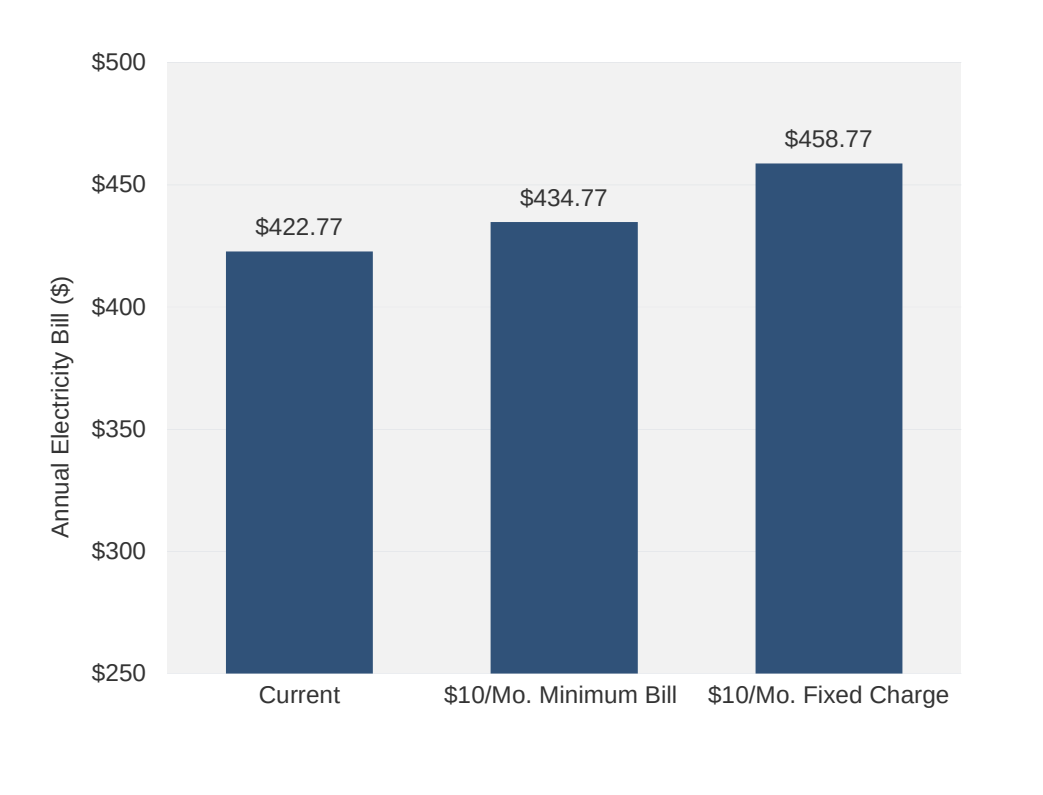
	Net Elec. Use (kWh)	Vol. Elec. Bill	NEM Credit	Fixed Dist. Charge	No- Min. Elec. Bill	Min. Bill Charge?	NEM Credit Used	Total Elec. Bill
Jan.	427	$74.07	$0.00	$7.00	$81.07	N	$0.00	$81.07
Feb.	266	$46.05	$0.00	$7.00	$53.05	N	$0.00	$53.05
Mar.	-49	$0.00	$8.42	$7.00	-$1.42	Y	$0.00	$10.00
Apr.	-159	$0.00	$27.55	$7.00	-$20.55	Y	$0.00	$10.00
May	-22	$0.00	$3.74	$7.00	$3.26	Y	$0.00	$10.00
Jun.	218	$37.77	$0.00	$7.00	$44.77	N	$34.77	$10.00
Jul.	324	$56.14	$0.00	$7.00	$63.14	N	$4.94	$58.20
Aug.	267	$46.31	$0.00	$7.00	$53.31	N	$0.00	$53.31
Sept.	-75	$0.00	$12.96	$7.00	-$5.96	Y	$0.00	$10.00
Oct.	22	$3.81	$0.00	$7.00	$10.81	N	$0.81	$10.00
Nov.	234	$40.61	$0.00	$7.00	$47.61	N	$12.15	$35.46
Dec.	500	$86.68	$0.00	$7.00	$93.68	N	$0.00	$93.68
Total								$434.77

Source: GTM Research and Genability

A $10 minimum bill would result in the typical Massachusetts solar customer paying an additional $12 more each year. The customer would pay an additional $3 for each of the four months (March, April, May and September) that the minimum bill charge is activated.

While a $12 increase to the typical Massachusetts solar customer's annual electricity bill may limit savings and hamper the value proposition of solar, it is undoubtedly preferable to a $10 fixed charge.

Figure 2.10 Annual Customer Bill – Current, Minimum Bill and Fixed Charge



This $12 increase represents a 2.8% jump in a typical Massachusetts solar customer's annual electricity bill, resulting in a 2.2% decline in the system's NPV. However, a $10 minimum bill would have a smaller impact on a solar customer's annual total electricity bill than would a $10 fixed charge, saving the customer $24 over the year.

Based on this analysis, we believe the minimum bill may present a palatable compromise for solar advocates and utilities in other states.

2.3.4. State Market Analysis

Figure 2.11 Key Residential State Markets in Review, Q2 2012-Q2 2014

Installations (MWdc)	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
California	45.5	53.2	56.1	78.6	84.9	104.6	141.8	129.7	140.3
Arizona	13.8	16.3	18.2	16.6	15.2	16.9	24.0	23.0	19.1
Hawaii	12.2	13.2	22.4	22.8	18.8	16.1	25.6	17.5	14.1
New York	2.5	4.0	5.9	3.0	5.1	6.1	13.2	9.1	11.9
Connecticut	0.6	1.9	2.6	1.7	2.0	2.2	1.4	1.4	0.8

Installations (MWdc)	2012 (Cumulative)	2013	Q1 2014	Q2 2014
Louisiana	12.4	21.6	6.9	3.4

California: Market Moves Full Steam Ahead Without CSI

- 140 MW installed in Q2 2014
- Up 65% over Q2 2013
- Up 8% over Q1 2014

In Q2 2014, California added more than 140 MW of residential installations for just the second time ever, falling 1.5 MW shy of the state's record total set in Q4 2013.

In previous sections, we noted that the state's residential market achieved triple-digit MW growth despite the depletion of residential rebates offered by the California Solar Initiative (CSI) for PG&E and SCE customers, and soon for SDG&E customers as well. With state incentives now a secondary driver of demand across the IOUs, the conversation surrounding why California's market continues to grow is linked to market dynamics driven by retail rate design, installers' growth strategies, and the diversification and expansion of homeowner financing solutions.

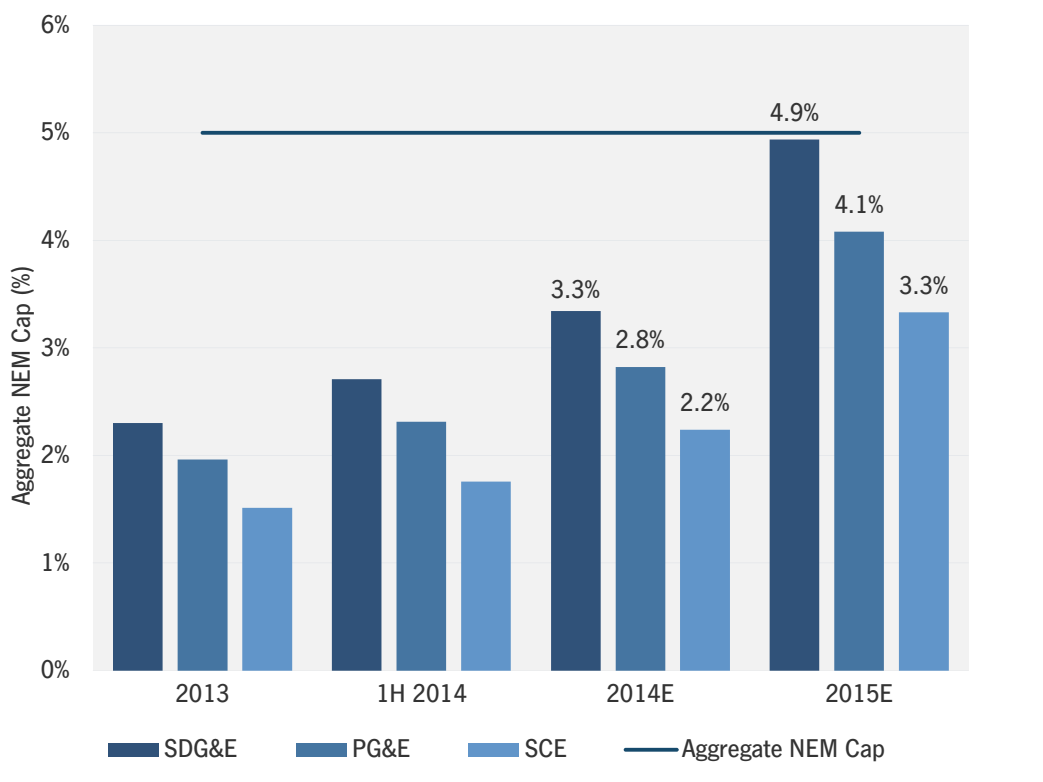
- **Retail rate hikes have increased solar's appeal for customers with low energy use:** Retail electricity rates across the investor-owned utilities vary depending on consumption and time of day, with four tiers of rates that are priced higher at peak periods of electricity demand. Keeping that in mind, 1H 2014 marks the first period in which installers are beginning to offer PPAs and leases to customers who use less energy and more often fall within the first two retail rate tiers. The savings are slimmer for such customers, but installers note that they still manage to offer 10% to 20% discounts to customers within the lower two tiers.
- **The installer landscape is becoming increasingly saturated:** A small pocket of installers originally based on the East Coast are ramping up operations within the state to further fuel market growth. Meanwhile, several in-state installers based in Southern California note that they are piloting sales offices in Northern California, and vice versa for installers with roots up north in PG&E territory.

- **Homeowner financing solutions continue to expand and diversify:** In particular, PACE has become an increasingly attractive financing option through which homeowners can afford to own a solar PV system or secure a prepaid lease, with the most popular option being the HERO PACE program, which is expected to be available in more than 100 communities by year's end.

The second half of 2014 is expected to be another record stretch for California's residential market, with many installers noting that sales significantly outstripped systems brought on-line in 1H 2014. Based on the continued availability of third-party financing solutions, along with the increasing penetration of PACE and other loan products, California's market remains well positioned to sustain its position as the top residential state market.

Looking out beyond 2014, impending revisions to net metering and rate design by way of the legislation AB 327 are poised to be primary determinants of residential solar economics in California. However, while SEIA and its members are actively engaged in this process, it will be some time before we find out the extent to which the four-tier rate structure will be flattened, and there is still uncertainty regarding the timeline for phasing in rate reforms and monthly fixed fees of up to $10/month. Equally important, the CPUC has until December 2015 to finalize the next net metering program, which will take effect on July 1, 2017 or when each utility hits a predefined capacity limit (whichever occurs first). Based on GTM Research's outlook for the three IOUs, however, SDG&E and PG&E are both expected to be less than 1% away from reaching their respective NEM capacity limits by the end of 2015, making December 2015 a crucial deadline for the CPUC to meet in order to ensure a smooth transition into the next NEM program.

Figure 2.12 Aggregate NEM Capacity by IOU, 2013-2015E

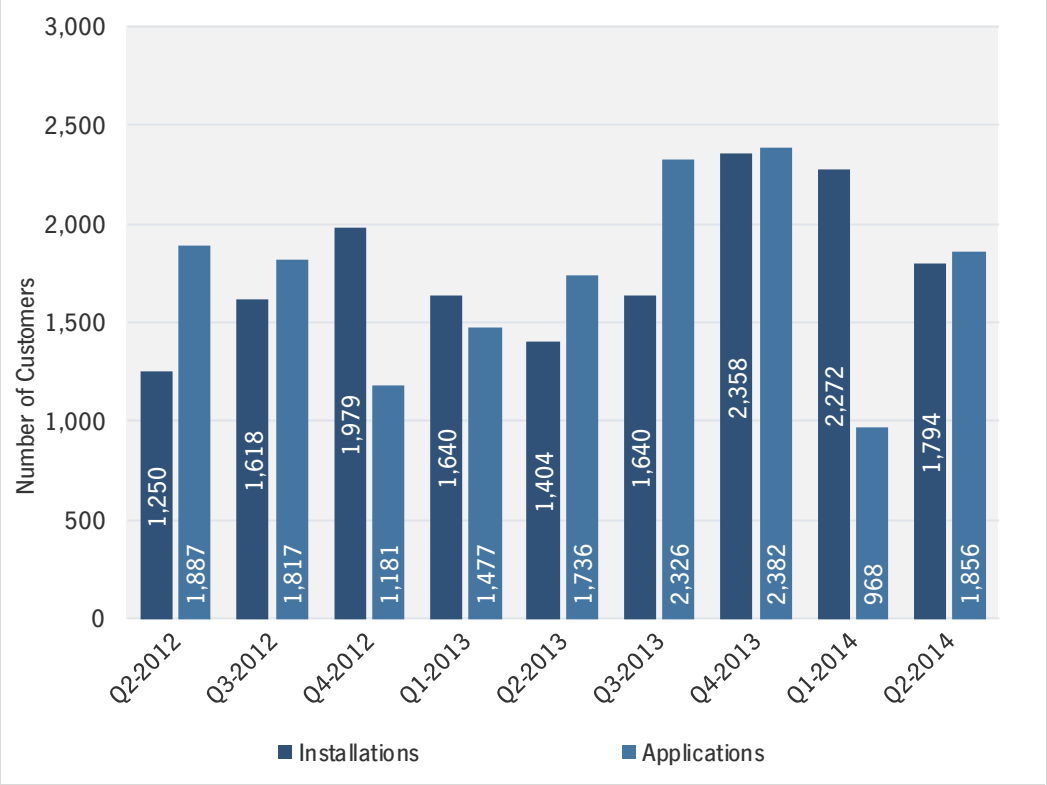


Arizona: Applications Bounce Back After Q1 Sales Lull

- 19.1 MW installed in Q2 2014
- Down 17% over Q1 2014
- Up 26% over Q2 2013

In Arizona, a new monthly net metering fee of $0.70/kW/month took effect for residential customers in Arizona Public Service (APS) territory who submitted PV interconnection applications starting January 1, 2014. The first half of 2014's year-over-year growth stemmed from the large pipeline of residential PV customers that locked into deals in Q4 2013 in order to be grandfathered in under the old NEM program. Alongside strong build rates for residential solar, however, the residential market in APS territory experienced a sharp decrease in sales and interconnection applications in Q1 2014, and subsequently, installations in Q2 dropped as well.

Figure 2.13 Number of Residential PV Installations vs. Interconnection Applications in APS Territory, Q2 2012-Q2 2014



The backlog of applications also spilled over into Q2, and, as Figure 2.13 shows, applications have bounced back. This is consistent with installers' reports, which have indicated a rebound in sales as customers' confusion and concerns about the NEM fee have subsided. Other growing sources of demand include the following:

- Installers are moving more into other utility territories, particularly Salt River Project, as a hedge against NEM uncertainty in APS. This is especially true of national companies that can more easily set up new offices.

- As in California, the solar market is tied to the housing market. As the latter has rebounded, installers have leveraged their homebuilder partnerships and incentives available for new home construction to drive new sales.
- Though the plans would not be implemented until 2015, APS and Tucson Electric Power (TEP) have filed proposals to install and own solar installations on residential homes with a total capacity of 20 MW and 3.5 MW, respectively. APS plans to partner with installers (with a preference for local companies) and compensate participating homeowners $30/month for a period of twenty years. Rather than paying homeowners a monthly fee, TEP will offer homeowners a fixed monthly electric rate for 25 years based on historical usage.

Despite overall growth in the residential market, third-party solar providers were hit hard by a recent ruling from the Arizona Department of Revenue that third-party-owned systems are no longer exempt from property taxes. SolarCity and Sunrun have filed a lawsuit against the state's Department of Revenue, but if the ruling ultimately stands, existing and future residential systems that are third-party-owned would incur a new property tax equal to $152 for an average 7.8 kW system in its first year of operation. GTM Research has calculated that this tax will increase the LCOE for these systems by 0.5 cents per kilowatt-hour to 11.6 cents per kilowatt-hour, slightly above the average residential retail rate of electricity. The share of third-party-owned residential systems has already fallen over the past year, and the tax would further hamper that sector of the market. Local installers have already noted an increase in the prevalence and popularity of loan products.

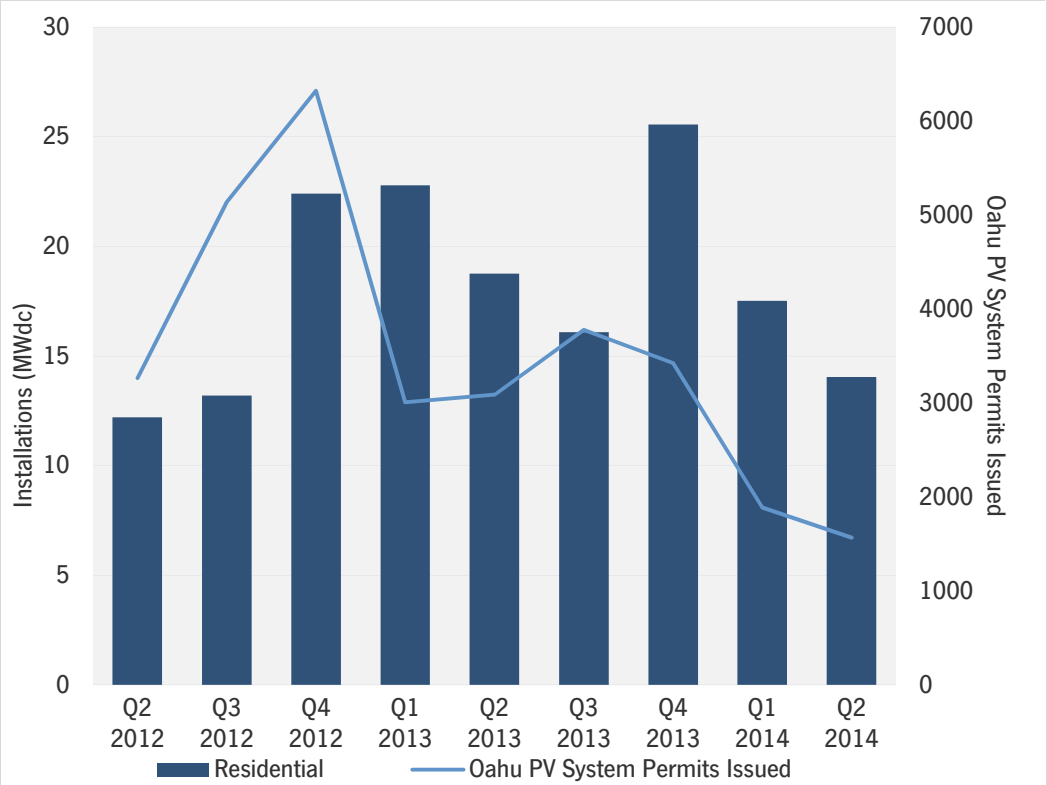
Hawaii: Growth Remains Limited Due to PV Grid Saturation Challenges

- 14.1 MW installed in Q2 2014
- Down 25% over Q2 2013
- Down 20% over Q1 2014

In Q2 2014, Hawaii's residential market continued to dip as development opportunities decreased across a growing number of neighborhoods that have reached PV penetration levels at or above 100% of minimum daytime load (DTL). As a result, for the second straight quarter, the residential market dropped both quarter-over-quarter and year-over-year.

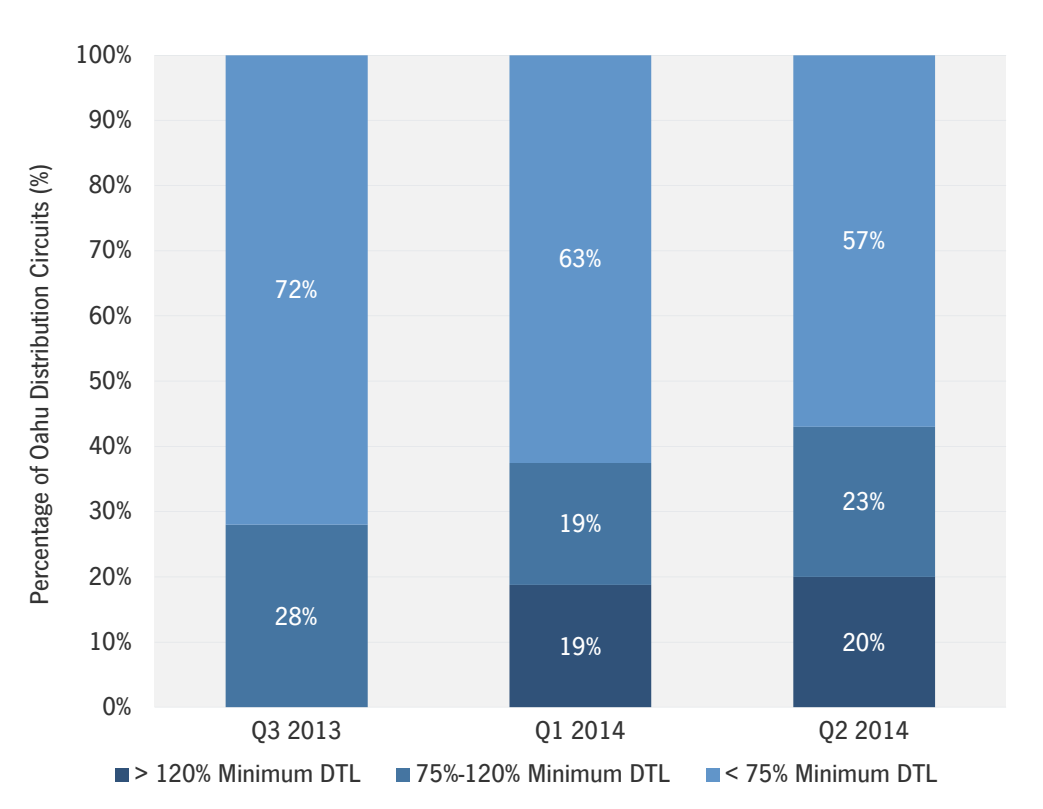
As mentioned in previous editions of this report, HECO, MECO, and HELCO now all require new PV customers to submit net metering agreements before proceeding with installation. In September 2013, the utilities issued new interconnection rules for solar customers in neighborhoods with high PV penetration levels. Specifically, a new solar customer with a system 10 kW or smaller in size may have to pay for equipment upgrades once PV circuit penetration is at 75% minimum DTL or higher. Meanwhile, customers with systems larger than 10 kW may have to pay for equipment upgrades regardless of the current PV grid saturation level. Finally, as of March 2014, interconnection studies will now only be required for new PV systems of 10 kW or smaller if grid saturation has hit 120% minimum DTL.

Figure 2.14 Residential PV Installations vs. Oahu PV Permits Issued, Q2 2012-Q2 2014



As Figure 2.14 reveals, in 2013, the residential market successfully rode off the backlog of PV permits pulled at the end of 2012. But with the introduction of new interconnection rules last fall, HECO has struggled to manage the growing volume of interconnection requests on circuits with high PV penetration, further compounded by a growing number of new circuits that have since reached the 75%, 100%, and 125% minimum DTL thresholds. As the state PUC puts it, HECO has been playing a game of "catch-up" in managing PV grid saturation challenges, with more than 40% of Oahu's 416 distribution circuits now at or above 75% minimum DTL.

Figure 2.15 Percentage of Oahu Distribution Circuits With PV Penetration at or Above 75% Min. DTL



While the market was down year-over-year in 1H 2014, growth rates could have been even more anemic if not for the backlog of customers awaiting interconnection approval from back in 2013. According to the PUC, nearly 3,000 customers on Oahu with NEM applications submitted after the interconnection rule changes in September 2013 were still awaiting interconnection approval as of January 2014.

For the remainder of 2014, the overflow of customers with pending interconnection approvals either from late 2013 or early 2014 is expected to bolster installations, along with the typical Q4 bump as installers rush to complete projects by year's end to monetize the in-state tax credit. However, based on conversations with installers on the ground, as well as PV permit data, all signs point to a minimal uptick in in the second half of 2014 that should pale in comparison to the second halves of 2012 and 2013.

Despite the bearish outlook for Hawaii, the PUC has ordered HECO to devise an integrated action plan this fall in order to address high-PV-penetration circuits and improve the interconnection approval process. While this is easier said than done, the PUC order at the very least launches a regulatory framework via which HECO can take more aggressive steps to manage additional PV penetration.

New York: A Turning Point for Residential Solar

- 11.9 MW installed in Q2 2014
- Up 31% over Q1 2014
- Up 133% over Q2 2013

Q2 2014 was the third consecutive quarter during which New York's residential market more than doubled year-over-year. The rapid growth in the first half of this year indicates that 2014 is a turning point for the state's market. Contributing factors include installers who entered New York in 2012 and 2013 now ramping up sales, new installers that are still entering the market, and spiking electricity prices in several utility territories.

Growth has been particularly robust in PSEG Long Island (formerly Long Island Power Authority) territory as more installers have set up shop. Installers have noted that a local presence is critical to landing customers and maintaining operations on Long Island relative to the rest of New York, and they are beginning to move up the learning curve. In addition to that, NYSERDA injected PSEG LI's Solar Pioneer rebate program with $5 million in funding late last year, which gave installers extra incentive to ramp up their presence on Long Island. For the remainder of 2014, PSEG LI's market is now even more attractive with the introduction of an On-Bill Recovery loan program that allows solar customers to repay loans to local installers via their electric bill.

Connecticut: Clerical Error Prompts Incentive Change

- 0.8 MW installed in Q2 2014
- Down 44% over Q1 2014
- Down 63% over Q2 2013

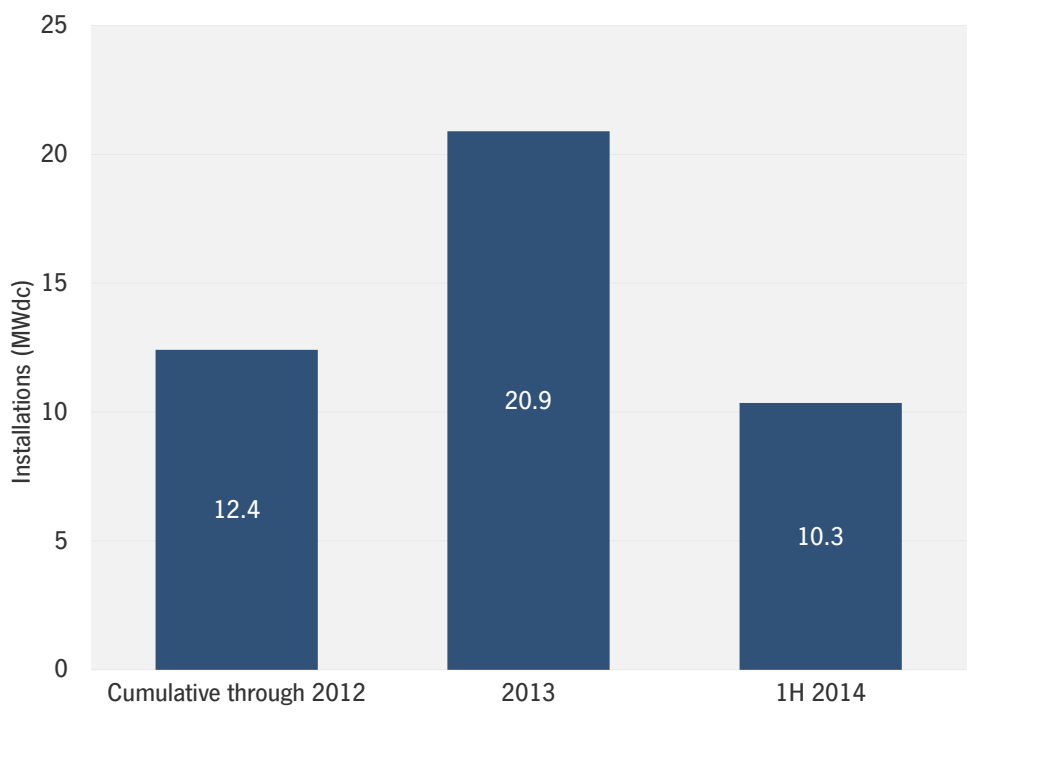
Connecticut experienced a particularly weak Q2, with just 0.8 MW of residential solar installed, due in part to a clerical error in a recently passed bill that halted rebate applications in early June. The law was being amended to fix a loophole so that systems could not receive both the rebate (intended for customer-owned residential systems) and the performance-based incentive (intended for third-party owned systems), but the change mistakenly referenced net metering instead of the PBI. Thus, it made customer-owned systems that receive the rebate ineligible for net metering, and the Clean Energy Finance and Investment Authority (CEFIA) stopped approving rebate applications when the error was discovered on June 10.

CEFIA quickly responded by creating a new incentive for customer-owned systems, the Homeowner Performance-Based Incentive. Available beginning July 14, the HOPBI will be equivalent to the upfront rebate, but paid out after the system achieves a 30-day performance target. Installers may now receive a zero-interest working capital loan so that they may still pass on immediate savings to the customer. Aside from the month-long delay in waiting for the new incentive, this could add to the already high administrative costs of CEFIA's incentive programs. Additionally, all incentives will drop when Step 5 of the Residential Solar Incentive Program takes effect on September 1. Nonetheless, the new wave of funding will pave the way for growth in the second half of 2014.

Louisiana: Attractive In-State Tax Credit Brings Market Onto National Radar

- 3.4 MW installed in Q2 2014
- Down 3.5 MW compared to Q1 2014

Figure 2.16 Louisiana Residential PV Installations, Pre-2013 Cumulative-1H 2014



Although Louisiana lacks an RPS, the state burst onto the scene in 2013 as a top-ten residential market due to its attractive 50% in-state tax credit, compounded by a rush to install systems ahead of impending revisions to tax credit rules in 2014.

More specifically, the summer of 2013 was a busy stretch for Louisiana's residential market. In June of that year, the Louisiana Public Service Commission first voted to keep net metering rules unchanged, electing to have NEM systems remain compensated at the full retail rate rather than at a wholesale avoided-cost rate. The following month, the state legislature passed Act 428, which guaranteed that the state tax credit would remain unchanged at 50% of the first $25,000 of a system's cost for solar PV systems through 2017. However, the legislation limited the tax credit that third-party-owned (TPO) systems could claim beginning in 2014. The following figure shows the maximum credit a TPO system has been and will be able to claim by installation date. In short, the tax credit for TPO systems is scheduled to decline three times, with the maximum credit scheduled to drop from $12,500 in 2013 to $4,560 in 2H 2015.

Figure 2.17 Louisiana Tax Credit Rules for Third-Party-Owned Systems

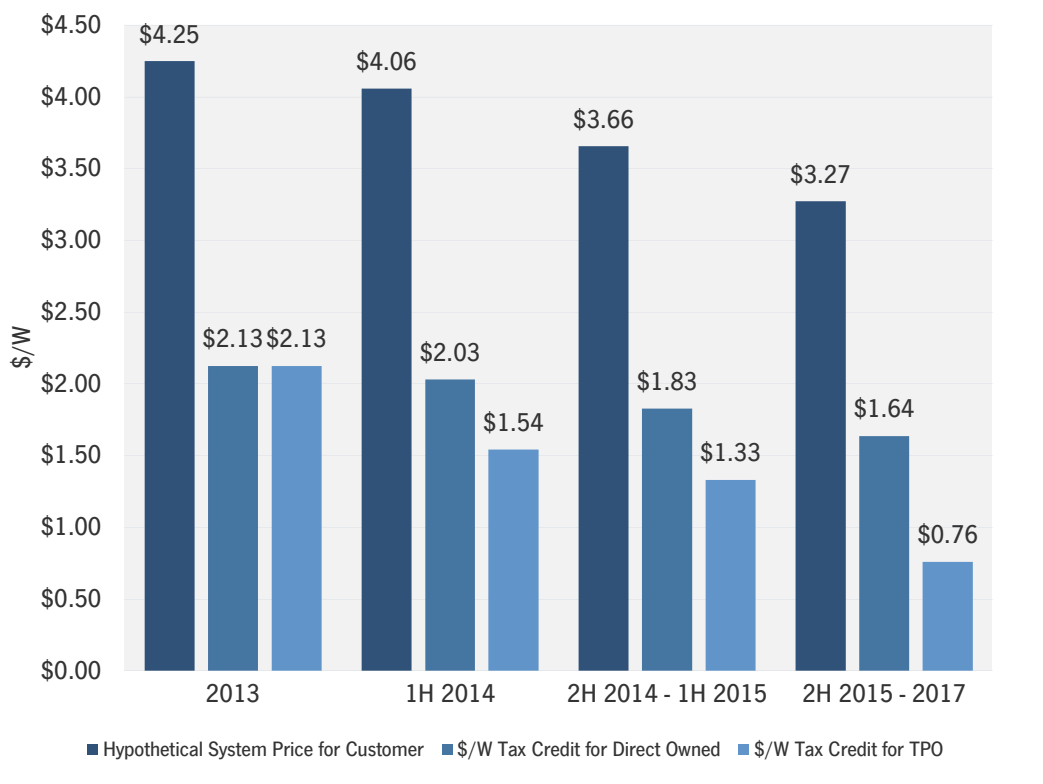
Installation Date	Maximum Cost Basis	Maximum Credit (% Basis)	Maximum Credit Claimed ($)
2013	Lesser of $25,000 or $4.50/W*system size	50%	$12,500
1H 2014	Lesser of $25,000 or $4.50/W*system size	38%	$9.500
2H 2014-1H 2015	Lesser of $21,000 or $3.50/W*system size	38%	$7,890
2H 2015-2017	Lesser of $25,000 or $2.00/W*system size	38%	$4,560

Amidst impending revisions to the state tax credit rules for TPO systems, installers offering leases ramped up their sales efforts in the second half of 2013 in order to bring on-line as many systems as possible with the 50% tax credit. Leading up to the final passage of Act 428, installers with a focus on direct cash sales claimed that certain leasing companies pitched deals to customers by claiming that the credits may expire altogether at the end of 2013.

With leasing companies at full steam ahead, Louisiana added more residential installations in 2013 than the state's cumulative residential market through 2012, with well over half of the market driven by third-party ownership. The first half of 2014 built off 2013's momentum by adding just over 10 MW of residential installations. With the gradual uptick of national installers and financiers, Louisiana is expected to experience incremental growth in 2014.

Beyond 2014, continued growth will depend on tighter margins for TPO systems as the tax credit drops, diminishing the ability of local installers to achieve scale. The figure below showcases a hypothetical 5 kW system and system prices (none of which is intended to reflect GTM Research's or SEIA's official system price outlook for Louisiana). Nevertheless, Figure 2.18 provides a useful approach to visualize the attractiveness of a state incentive that could translate into a $1/W or greater discount for all-in system prices for a typical residential system through 1H 2015.

Figure 2.18 Louisiana Residential State Income Tax Credit by Ownership Type, 2H 2013-2017



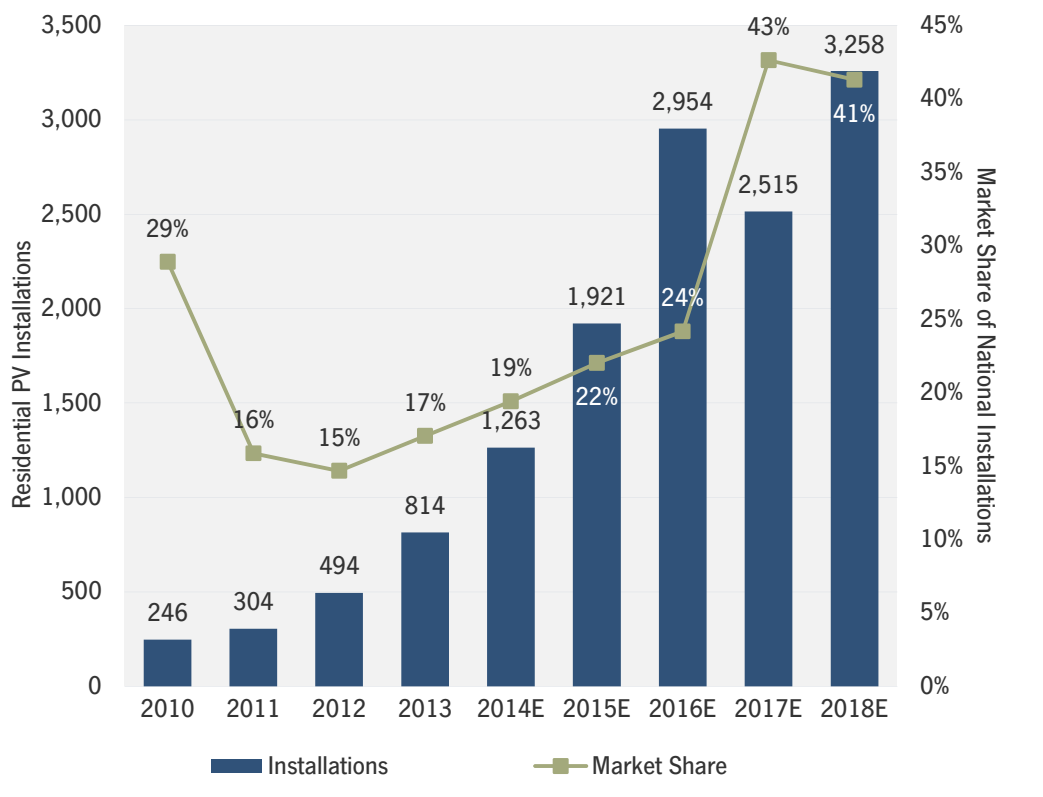
2.3.5. Residential Market Outlook

We maintain a highly positive view on the growth trajectory of residential solar installations in the U.S. Our forecast calls for 1,263 MW to be installed in that segment in 2014, representing 55% growth over 2013. The residential market will continue to gain share in terms of national installations, reaching 19% in 2014 and topping out at 43% in 2017, assuming the 30% ITC expires as scheduled. In this updated forecast, we now call for the residential market to exceed non-residential solar installations in 2015. Most notably, we forecast that it will become the largest market segment beginning in 2017. This outlook has as much to do with residential solar's continued ability to grow in spite of declining state incentives as it has to do with non-residential solar's murkier roadmap to achieving scale in the near term (additional context for our non-residential market outlook can be found in the Non-Residential Market Outlook in Section 2.4 of this report).

Our overall forecast for residential solar is bullish for a number of reasons. First, several states (California, Arizona and Nevada, among others) are just beginning to see meaningful volumes of systems installed without the support of any state- or utility-level incentive program, which bodes well for growth in these states. Second, the early results of net energy metering disputes have largely been positive for solar installers, which continue to operate in all states that have experienced NEM battles. Finally, the introduction and expansion of new financing programs – both consumer- and project-based – will continue to enable a wider class of customers to install solar and avoid financing bottlenecks.

The primary risk factor in the residential market remains the ultimate outcome of rate structure and NEM debates in major states. In California, for example, our forecast indicates that the caps for customers under the current NEM regime will be hit in mid-2016 for two of three IOUs. Thus, our 2017-2018 forecast is predicated on a relatively smooth transition to whichever successor program is adopted by the CPUC.

Figure 2.19 Residential PV Market Forecast and Market Share, 2010-2018E



2.4. Non-Residential PV

2.4.1. National Level Figures

- 261 MW installed in Q2 2014
- Up 16% from Q2 2013
- Up 13% from Q1 2014

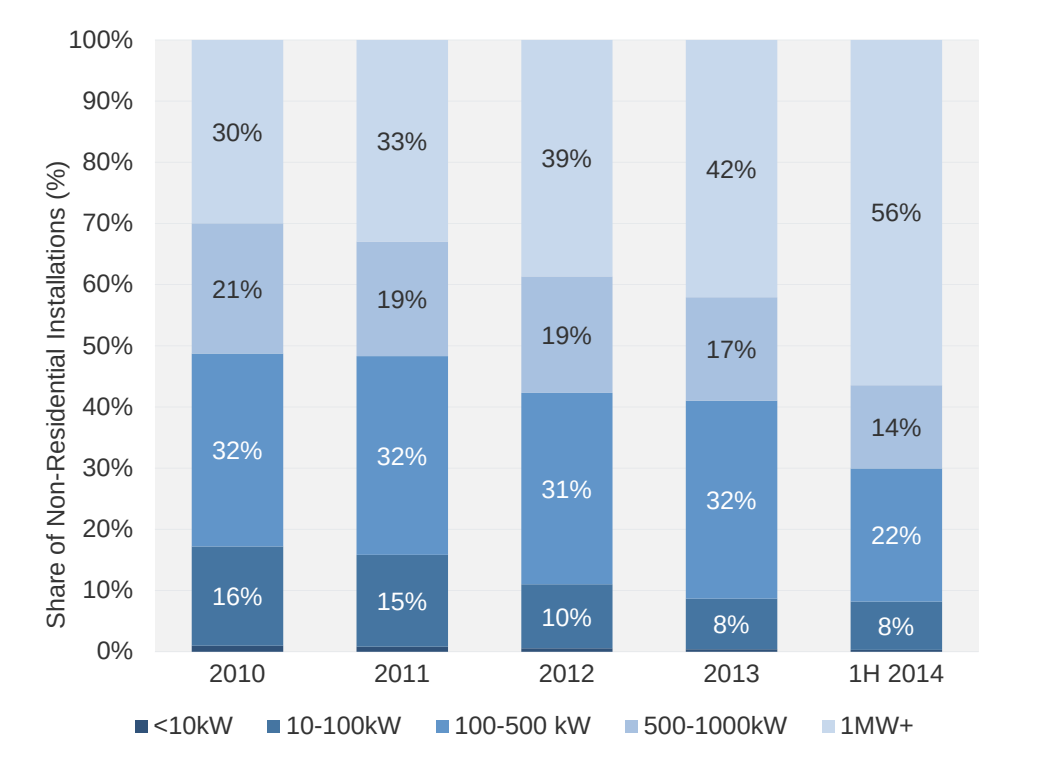
The non-residential market continues to be characterized by lumpy development cycles and the ebb and flow of incentive levels across a select number of states. In Q2 2014, non-residential installations increased 13% over Q1 2014, although they remained well below the record growth levels that occurred in the final quarter of 2013. The incremental rebound that did occur, however, can be largely attributed to an uptick in Massachusetts (up 370% quarter-over-quarter), California (up 14% quarter-over-quarter), and, surprisingly, Missouri, which added more than 10 MW for the first time ever in Q2 2014. In the second half of 2014, we expect continued growth in Massachusetts, California, and New York, along with consistent demand in New Jersey as SREC prices stabilize further.

2.4.2. Non-Residential Market Trends: System Sizes

Though the availability of capital has vastly increased for non-residential solar over the past five years, it has remained exceedingly difficult to finance and develop small commercial solar projects. These projects often have varying contract terms, power purchasers that lack credit ratings or easily assessed creditworthiness, and site-specific project requirements. What's more, the transaction costs associated with smaller commercial projects are nearly the same as those for a much larger deal. These difficulties have generally led developers to focus their attention on larger commercial projects, particularly those larger than 1 MW.

This dynamic has only become more heightened over time. In 2010, 70% of all non-residential systems installed were less than 1 MW in size, whereas only 44% of the systems installed in the first half of 2014 were in this category. The decline has been particularly stark for projects smaller than 100 kW in size, whose market share has been cut in half over the same period.

Figure 2.20 Non-Residential PV Installations by System Size

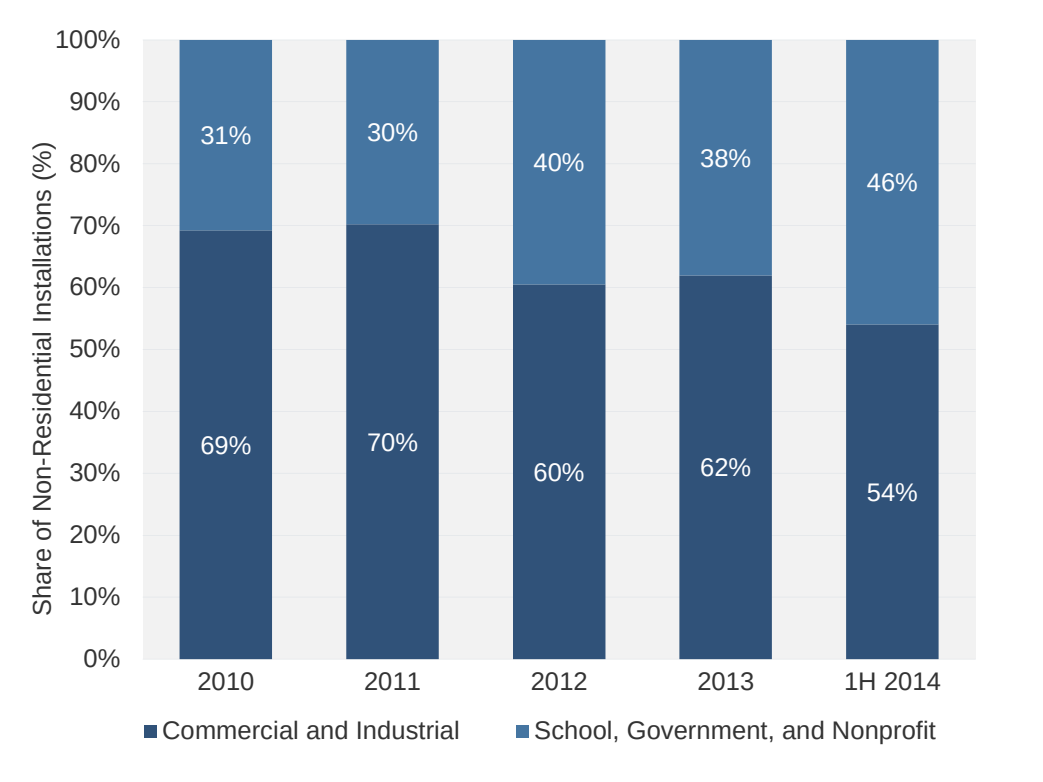


It is important for the market to improve its capabilities in the small commercial arena, in no small part because the theoretical market potential for that segment is virtually boundless by today's standards. Fortunately, we foresee a number of developments that should aid in this transition. First, states such as Massachusetts and New York are rolling out incentive programs with specific carve-outs for small commercial, recognizing the need for that segment to be treated independently. Second, we have seen a variety of companies seek out innovations to lower the administrative burden associated with financing small commercial through solutions such as project scores, online diligence tools, and investment platforms. Finally, some larger commercial developers have begun building small commercial assets on their own balance sheet as a proof-of-concept to attract third-party capital. We remain optimistic that the relative share of large commercial systems above 1 MW will slow and demand will increasingly shift towards smaller systems below 1 MW over the coming years.

2.4.3. Non-Residential Market Trends: Customer Segments

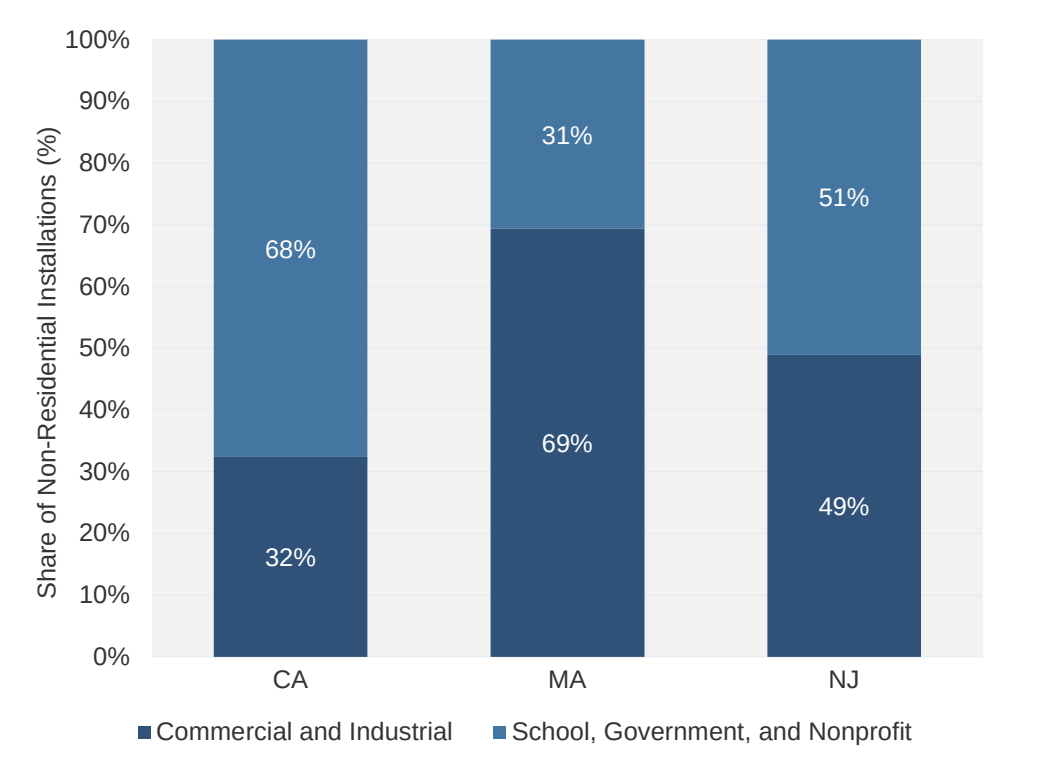
Much of the recent growth in the non-residential sector has come from public sector installations at schools, government buildings, and, to a lesser extent, nonprofits. This segment has grown from an estimated 31% of all non-residential installations in 2010 to 46% through the first half of 2014.

Figure 2.21 Non-Residential PV Installations by Customer Segment, 2010-1H 2014



This breakdown, however, is highly state-specific. California has recently been largely a public-sector market, with such installations representing 68% of the market so far this year. Massachusetts has been just the opposite; 69% of first-half installations came from the private sector. New Jersey shows the most balance of major markets, with a 51%-to-49% split between the public and private sectors.

Figure 2.22 1H 2014 Non-Residential PV Installations by Customer Segment, CA, MA and NJ



2.4.4. State Market Analysis

Figure 2.23 Key Non-Residential State Markets in Review, Q2 2012-Q2 2014

	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
CA	48.9	73.8	98.0	58.9	64.3	83.9	85.6	59.9	68.0
AZ	13.0	7.2	34.1	7.7	5.3	23.5	21.7	28.5	5.2
MA	19.2	36.4	40.4	21.8	17.5	37.6	93.9	18.6	87.4
NY	5.6	6.8	17.4	3.1	5.7	6.7	27.0	11.8	9.7
MO	0.8	0.8	1.7	4.2	2.6	2.7	4.4	5.3	12.1

California and Arizona: School, Government, and Nonprofit Installations Dominate Market Growth

- California: 68 MW installed in Q2 2014, up 14% quarter-over-quarter and 6% year-over-year
- Arizona: 5.2 MW installed, down 82% quarter-over-quarter and 1% year-over-year

While the residential markets in California and Arizona have experienced continued growth despite the depletion of state-level incentives, incentive levels across these states' non-residential markets have shifted installation growth

heavily toward the government/nonprofit sector. It is important to note that in Q1 2014, Arizona added a 16.4 MW solar project with a PPA signed by the U.S. Air Force. Excluding that system, however, Arizona's non-residential market in Q2 2014 would have still dropped 57% quarter-over-quarter in Q2 2014.

The drop-off in Arizona's non-residential market and the incremental uptick in California's speak volumes about the extent to which both incentive availability and volatility continue to drive demand across leading state markets. Arizona's commercial segment of the non-residential sector has seen a stark decline in installations after the end of performance-based incentives for large commercial projects in both APS and TEP territories early last year. Since incentive funding remained available for school and government projects throughout 2013, these projects have accounted for the majority of the state's non-residential market dating back to Q4 2013.

In California, PBIs offered by the California Solar Initiative are depleted in PG&E territory. Meanwhile, in SCE and SDG&E territories, PBIs are approximately $0.06/kWh to $.08/kWh higher for government/nonprofit customers than for commercial customers. As a result of the higher incentive level for government/nonprofit customers, these installations drove a majority of non-residential installations across the IOUs in 2013 and 1H 2014. Looking forward to the rest of this year, these states are expected to see demand become further dominated by the government/nonprofit sector as non-residential levels drop to the final CSI step for SDG&E (SCE is already in Step 10), and as Arizona's pipeline of projects with PBIs reserved in 2012 further depletes.

In 2015 and beyond, California's market will be a litmus test for the attractiveness of commercial solar without state incentives. A number of small and medium-sized commercial customers (i.e., those with average monthly peak demands of 200 kW or less) across the IOUs' territories are now transitioning away from flat rates to time-of-use (TOU) rate structures. The switch to TOU rate tariffs is expected to increase monthly bills for these low-usage customers, who will be attractive targets for developers. However, as is the case in California and the entire U.S., the prospect of tapping into small and medium-scale commercial customers remains constrained by the limited universe of investors willing to finance individual projects of less than 1 MW, oftentimes backed by non-investment-grade commercial offtakers.

Massachusetts: SREC I Extended Deadline Brings Second Boom

- 87.4 MW installed in Q2 2014
- Up 370% over Q1 2014
- Up 399% over Q2 2013

As expected, Massachusetts had a huge uptick in non-residential installations in Q2. For the second time in the past year, it had the largest non-residential market in the U.S. Under the terms of SREC I, systems larger than 100 kW that expended over 50% of project costs by December 31, 2013 were granted a six-month extension to complete construction and receive an authorization to interconnect by June 30, 2014. However, completed projects that can prove that interconnection was delayed by the utility after that deadline can be granted an additional extension. As of July 1, 2014, approximately 120 MW of non-residential systems that were qualified for SREC I had not been connected. A majority of that capacity is expected to come on-line in Q3, as the utilities approve the backlog of projects that submitted interconnection requests in June.

As mentioned, Massachusetts' solar PV market was highlighted by a comprehensive but controversial bill that included eliminating the net metering caps, replacing SRECs with performance-based incentives, and revising

rates downward for virtually net metered systems. However, the bill failed to pass before the end of the legislative session. Instead, stopgap legislation was passed that raised net metering caps from 3 percent to 5 percent for public projects and to 4 percent for private projects. With that in mind, rules surrounding the SREC II program, which officially began on April 25, 2014, remain the primary driver of future growth opportunities for the non-residential segment in the state.

Figure 2.24 SREC II Market Sectors by Eligible Projects, SREC Factors, and Annual Capacity Limit

Market Sector	Market Segment	SREC Factor	Annual Capacity Limit
A	Systems <=25 kW, solar canopies, emergency power generation units, community solar, and low/moderate income housing systems	1.0	N/A
B	Building-mounted systems, ground-mounted systems >25 kW with 67% or more of the electric output on an annual basis used by an on-site load	0.9	N/A
C	Landfill or brownfield projects and systems <= 650 kW with less than 67% of the electrical output on an annual basis used by an on-site load	0.8	N/A
Managed Growth	Unit that does not meet the criteria of Market Sectors A, B, or C	0.7	2014: 26 MW 2015: 80 MW

As shown in this table, approximately 26 MW of solar will come on-line by the end of 2014 through the managed growth sector. The low SREC factor for this sector is expected to exert downward pressure on EPC margins and further impact the value proposition for the development of large commercial ground-mount systems in the state. At the same time, because opportunities for large-scale projects are limited in SREC II, developers will need to deal with the challenge of financing small- to medium-scale systems of less than 650 kW.

New York: Reforms to Incentive Program Spur Large-Scale Solar Development

- 9.7 MW installed in Q2 2014
- Down 18% over Q1 2014
- Up 72% over Q2 2014

New York's solar market has seen the continued ramp-up of its non-residential market primarily via incentive programs administered by NYSERDA's NY-Sun program and PSEG Long Island (formerly LIPA). Throughout 2013, NYSERDA's Solar Incentive Program for systems up to 200 kW and the Competitive PV Program for systems greater than 200 kW in size accounted for 90% of the state's non-residential market. In 1H 2014, it was more of the same as NYSERDA drove 84% of New York's non-residential installations.

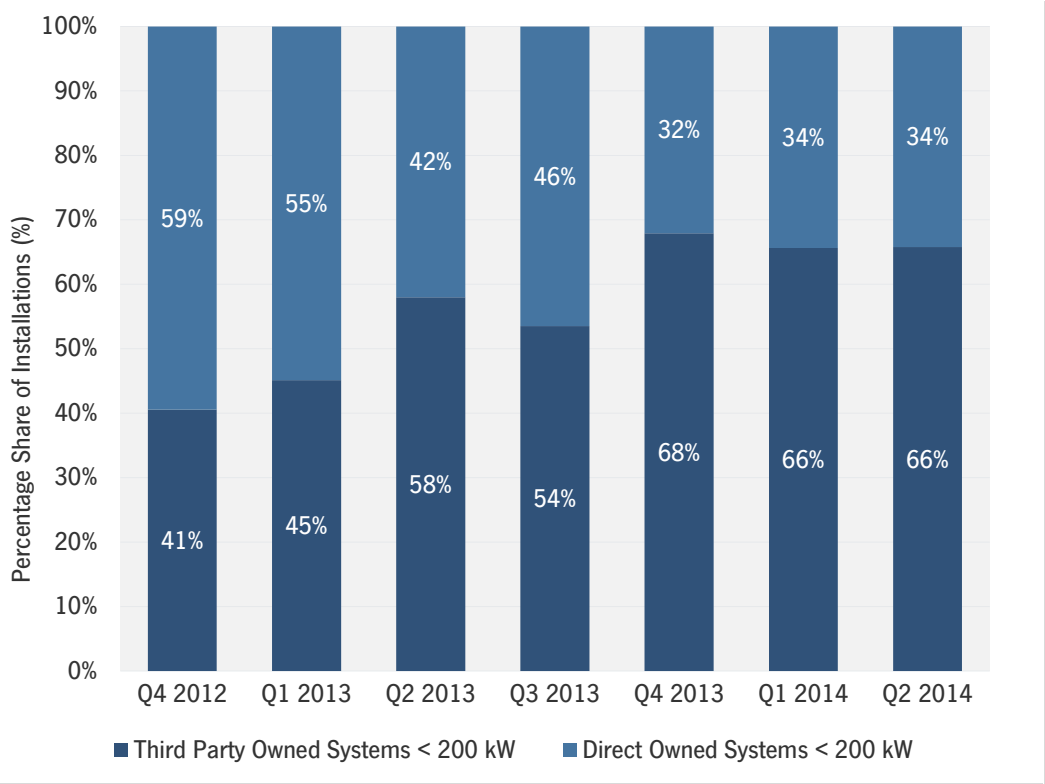
Within PSEG LI territory, the distinction between non-residential and utility PV becomes somewhat blurry. Net metering exists for non-residential customers, but the market also has a feed-in tariff (FIT) program called the Clean Solar Initiative for systems sized between 100 kW to 2 MW on the utility side of the meter. Across PSEG LI's non-residential market, a number of developers based outside of Long Island have struggled to bring projects on-line after underestimating construction, permitting, and interconnection costs, while both local and national developers have struggled to negotiate reasonable financing terms for projects structured as rooftop

property leases. PSEG LI's first FIT aimed to bring 50 MW on-line, yet less than 10 MW from the first round has come on-line to date. However, PSEG LI is increasing transparency regarding some of the costs that hindered development in the first program and is also implementing more stringent requirements aimed at improving the success rate of projects under the second 100 MW FIT program. With a lower FIT rate of $0.1688/kWh compared to $0.22/kWh in the first incentive round, uncertainty remains as to whether projects that are part of the second FIT can pencil out when so many failed to secure financing under the first.

Meanwhile, NYSERDA's NY-Sun program has undergone two major revisions to ensure that a larger number of non-residential projects come on-line:

- In mid- 2013, the maximum system size for NYSERDA's Solar PV Incentive Program was increased from 50 kW to 200 kW and the cap on how much capacity a developer could install under the program was lifted. Subsequently, installed capacity of sub-200 kW systems doubled year-over-year in 1H 2014 as a larger number of systems between 50 kW and 200 kW came on-line. With this revision has also come increased investment from third-party PPA and lease providers. As the following figure shows, small-scale non-residential installations have primarily been third-party-owned every quarter since Q2 2013, and are increasingly dominated by PPA-financed rather than leased systems.

Figure 2.25 NYSERDA Funded Non-Residential PV Installations of Less Than 200 kW by Ownership Structure, Q4 2012-Q2 2014



- NYSERDA's Competitive PV Program, for systems larger than 200 kW, has restructured its next incentive round by streamlining the distribution of incentives from two upfront rebates and a PBI for the first three years of system production to one upfront rebate and a PBI paid out over the first two years of production. Multiple developers have noted an ability to develop and finance large-scale commercial and government/nonprofit projects in the back half of 2014 at a faster pace and higher volume since they (or third-party financiers) can take advantage of the upfront rebates with lower transaction costs and capture all PBI payments one year sooner than would otherwise be the case.

Incentive applications for the fourth round of the Competitive PV program were due in July 2014, but the deadline for these systems to come on-line is April 2016. Given that, 2H 2014 and the beginning of 2015 will remain driven by the 100 MW+ backlog of systems awarded incentives during the first three rounds. These projects were all expected to come on-line by May 2014, but the minimal siting and permitting requirements to earn an incentive, coupled with overly aggressive incentive bids that resulted in prolonged financing negotiations, led to a number of delays. With that in mind, New York's non-residential market in 2014 is expected to nearly double last year's performance, with 80 MW forecasted primarily due to the continued spillover of projects funded by the Competitive PV Program.

Looking further out, New York's non-residential market is expected to become an even more attractive growth market with the rollout of NYSERDA's new MW Block Incentive Program, which will be available through 2023. Similar to the California Solar Initiative, this program's rebate levels step down as cumulative installed capacity targets are reached. The new rebate program has officially become available for systems of 200 kW or smaller, while the revamped incentive program for systems larger than 200 kW will launch in early 2015.

Missouri: Installations Skyrocket, But RPS Law Revision Threatens Solar Industry

- 12.1 MW installed in Q2 2014
- Up 131% over Q1 2014
- Up 368% over Q2 2013

Q2 was the largest quarter to date for Missouri's non-residential market, with almost as much solar installed during the quarter as there was in all of 2013. The impressive growth in 1H 2014 has less to do with Missouri reaching a tipping point in demand and more to do with a rush to qualify for utility rebate programs that were abruptly capped late last year.

The legislation that established a renewable portfolio standard in 2008 also includes a clause that allows utilities to limit renewable procurement if it would raise electricity retail rates by more than 1%. After the state passed legislation last August to step down solar rebates in the period 2014 to 2020, the utilities Ameren Missouri and Kansas City Power and Light (KCP&L) claimed that they had reached the 1% cap on retail-rate cost hikes. As such, Ameren elected to end rebate funding in December 2013, while KCP&L's two service territories placed a cap on rebate funding that will most likely be reached by the end of 2014.

In light of these announcements of the impending elimination of rebate funding, installers responded by rushing to submit as many incentive applications as possible. The installation of projects that had successfully reserved funds from Ameren led to a strong first quarter and a record-breaking second quarter, since any project installed before June 30 qualified for a $2/W rebate, with spillover installations receiving only $1.50/W.

The second half of 2014 will be driven by installations from KCP&L's rebate program, as well as projects that missed the first Ameren deadline.

Although the utilities have conditionally ended their rebate programs, a group of installers and Missouri homeowners are now suing the Missouri Public Service Commission for approving the freeze on rebate funding. The success or failure of this lawsuit in reopening the rebate programs will play a key role in determining the market's growth potential beyond 2014.

2.4.5. Non-Residential Market Outlook

Although the U.S. non-residential market only grew 3% in 2013, we expect the sector to rebound in 2014, growing 21% to reach 1,338 MW. The non-residential market will account for approximately one-fifth of national PV installations each year until 2017, jumping to a 34% national market share as the utility PV market drops off more rapidly in response to the federal ITC's scheduled dropdown to 10% (for commercial, utility and TPO projects) at the end of 2016.

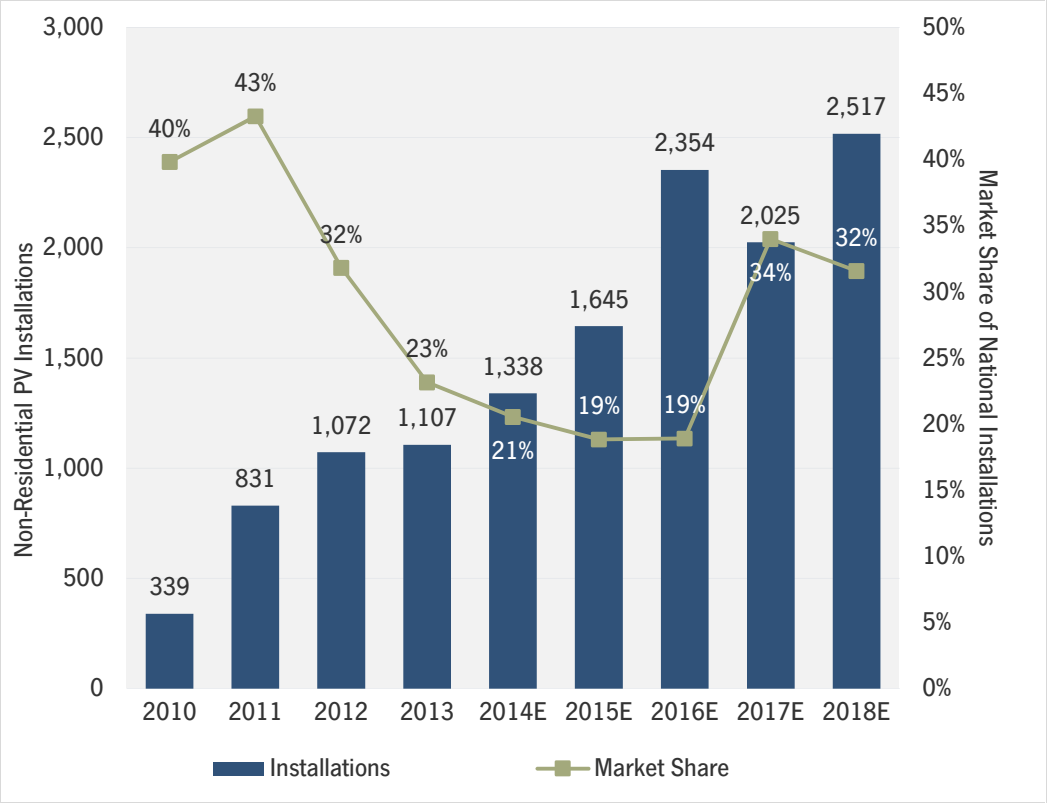
Our forecast projects that the non-residential market will grow 23% in 2015 and 43% in 2016, resulting in the non-residential market adding less capacity than the residential sector in 2015, the first time residential will outpace non-residential for an entire year since 2002. Across the major state markets, our forecast assumes that California will represent an early-mover opportunity for developers to tap into the small C&I space; that Massachusetts' SREC II program and New Jersey's revised RPS legislation will yield incremental growth; and that New York will shore up its position as a top-five state market due to a 3 GW expansion of the NY-Sun program through 2023.

Downside risk to the forecast lies in the market's continued sensitivity to state incentive reductions. Most notably, as the number of incentivized government/nonprofit installations dissipates in states such as Arizona and California, downward pressure on either EPC margins or PPA rates and lease terms remains a key challenge to sustained growth for this increasingly important segment.

On the other hand, the upside potential to our forecast lies in the non-residential market's ability to standardize project risk analysis for small commercial projects that have high transaction costs and, often, non-investment-grade offtakers. Equally important, developers are creating innovative business models to achieve scale, such as with the establishment of extensive, localized EPC dealer networks to generate replicable downstream channel partnerships.

Given that, the non-residential market remains in need of innovative strategies that transform how developers acquire customers, manage partnerships with outside EPC firms, and standardize access to financing. Solutions to all or even one of these three bottlenecks to growth would put the non-residential market on track to grow at a faster rate than the residential market in the near term, as it did several years ago.

Figure 2.26 Non-Residential PV Market Forecast and Market Share, 2010-2018E



2.5. Utility PV

2.5.1. National-Level Figures

- 625 MW installed in Q2 2014
- Drove more than 50% of national PV installations for the fifth straight quarter

In Q2 2014, the U.S. installed 625 MW of utility PV from 62 individual projects and project phases. This makes Q2 2013 the fourth-largest quarter ever for utility PV in the U.S. The majority of this capacity (476 MW) came from the four largest projects, all developed by First Solar.

Figure 2.27 Largest Utility PV Installations, Q2 2014

Project Name	Developer	Capacity (MWdc)	State	Power Offtaker	Owner
Desert Sunlight SCE - Phase II	First Solar	191.4	CA	Southern California Edison	NextEra Energy Resources, GE Energy Financial Services, Sumitomo Corp.
Antelope Valley Solar Ranch One - Phase III	First Solar	168.8	CA	Pacific Gas & Electric	Exelon Corporation
Macho Springs Solar Farm	First Solar	64.9	NM	El Paso Electric	Southern Company, Turner Renewable Energy
Topaz Solar Farm - Phase V	First Solar	51.2	CA	Pacific Gas & Electric	MidAmerican Energy Holdings

Source: GTM Research U.S. Utility PV Tracker

Beyond these large projects, the Q2 capacity comprised two distinct project types. First, 27 MW of utility PV were installed in nontraditional state markets, including Indiana, Missouri and Rhode Island. A number of developers have successfully found niches to develop projects of 1 MW to 10 MW in these and other markets which historically have seen relatively little solar. Second, 20 MW of small-scale utility PV (in the 1 MW to 3 MW range) came on-line in California through Southern California Edison's first Renewable Auction Mechanism (RAM) procurement (4.6 MW) and Pacific Gas & Electric's feed-in tariff program (13.0 MW).

Figure 2.28 Notable Installation Types – Q2 2014

Project Type	Capacity	Number of Projects	Developer(s)
Nontraditional Solar States	27 MW	5	Blue Renewable Energy, Strata Solar, MC Power, Megawatt Energy Solutions
California Small-Scale Utility PV	20 MW	13	sPower, Ecos Energy, Cenergy Power, Enerparc, Pristine Sun

Source: GTM Research U.S. Utility PV Tracker

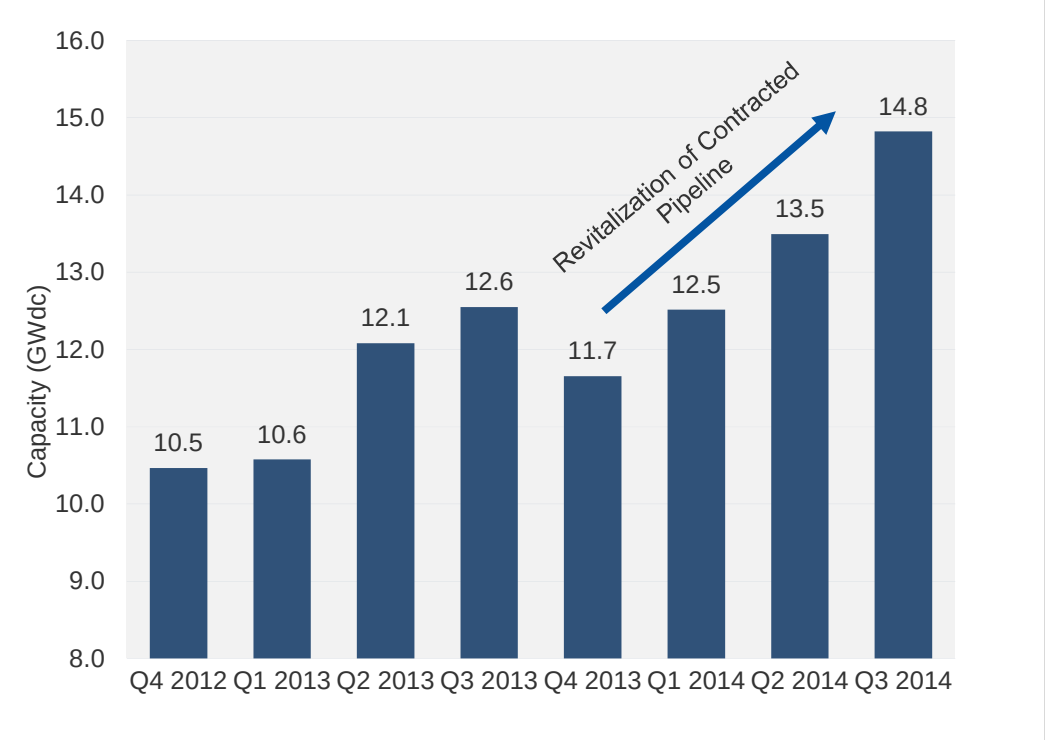
Both of these categories reflect a broader trend in the utility PV market: the transition from large, centralized development toward smaller projects with specialized procurement. The project pipeline remains full of such projects, but we believe a window of opportunity has reopened for larger projects.

2.5.2. Project Pipeline and Procurement Trends

In 2012 and 2013, the U.S. utility PV market experienced two divergent trends. On one hand, installations were growing at a rapid clip, outpacing the also-growing distributed PV market in the U.S. In 2013, the utility market installed 2,855 MW of capacity and accounted for 60% of the overall solar market – up from just 58 MW and 13% in 2009. But while installations expanded, the project pipeline – defined as projects with a utility PPA or equivalent contract – began to stagnate. Virtually all utility procurement had been enabled by state renewable portfolio standards, and utilities in key Western states including California, Arizona and Colorado had signed up enough capacity to meet their near-term requirements. As a result, new procurement dried up and developers were left with stranded assets.

That procurement valley resulted in hard times for a number of project developers and fostered M&A activity that involved both companies and projects. But over the past twelve months, two factors have been reshaping the market and rebuilding the contracted pipeline to the highest levels in the market's history.

Figure 2.29 Utility PV Contracted Pipeline, Q4 2012-Q3 2014



Source: GTM Research U.S. Utility PV Project Tracker

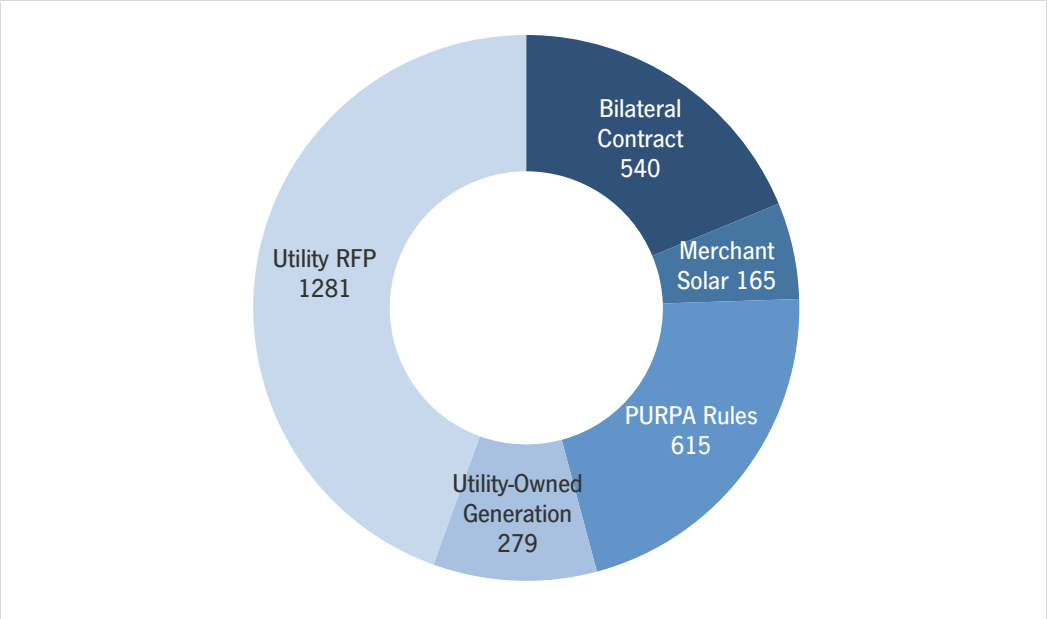
First, nearly 3 GW of projects have received contracts outside RPS requirements in the past year. The rationale for this has varied, but among the reasons noted:

1. Utility-scale solar is cheaper than building some new natural gas plants
2. Utility-scale solar serves as a hedge against natural-gas price volatility
3. It's a strategic shift to remove coal from utilities' generation resource mix
4. EPA's coal ash rule is requiring early retirements of certain utilities' coal fleets

Regardless of the specific reason, the cross-cutting theme is this: project developers have found gigawatt levels of new demand from utilities that realize utility-scale solar is either economically competitive with natural gas or is well suited to hedge against natural-gas price volatility.

The procurement mechanisms have also varied, ranging from bilateral negotiations with utilities to the landmark PURPA rules which have applied to cost-competitive generators since 1979.

Figure 2.30 Recent Non-RPS Utility PV Procurement Sources (MW), 2H 2013-1H 2014



Source: GTM Research U.S. Utility PV Project Tracker

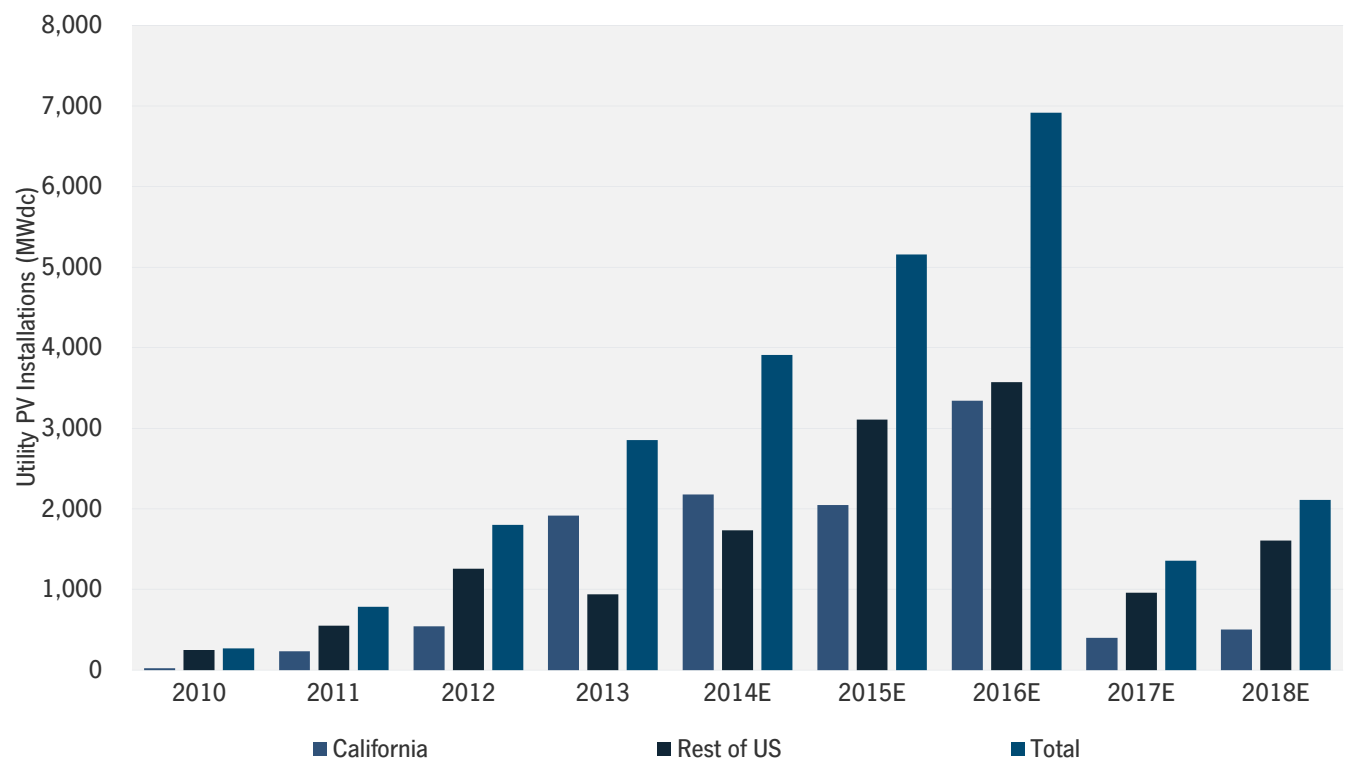
Also notable is the geographic diversity of these projects. The contracted pipeline outside California was 3.6 GW in 2012 and now sits at 6.1 GW, and it includes significant capacity in states such as Utah, Texas, Idaho, Georgia and Minnesota.

Second, utilities within California have resumed procurement to meet their RPS obligations further into the future. On August 1, for example, Southern California Edison announced PPAs for more than 1,300 MW of PV, with contracts beginning in 2019 and 2020. This has created opportunities for some of the once-stranded assets that may now be put to use in later years.

2.5.3. Utility PV Market Outlook

As a result of these trends, our outlook for utility PV installations in the U.S. has improved considerably. We forecast that 3.9 GW will be installed in 2014, up from just 269 MW in 2010, and that installation rates will continue to expand based primarily on the existing project pipeline through 2016. In that year, the utility segment will reach an impressive high of 6.9 GW – more than the entire U.S. market in 2014. This growth will occur both within California (3.3 GW in 2016) and outside it (3.5 GW in 2016), broadening the geographic scope of a market that has historically been highly concentrated in California (67% of 2013 installations).

Figure 2.31 Utility PV Installations, 2010-2018E



Installations (MWdc)	2010	2011	2012	2013	2014E	2015E	2016E	2017E	2018E
California	22	233	542	1,918	2,177	2,048	3,342	401	501
Rest of U.S.	247	551	1,261	937	1,734	3,111	3,573	958	1,609
Total	269	784	1,803	2,855	3,911	5,159	6,915	1,359	2,111

The outlook for 2017 and 2018, however, is much bleaker. Few developers are planning to place assets on-line in the aftermath of the step-down of the 30% federal Investment Tax Credit on December 31, 2016. Even those developers signing PPAs for 2018-2020 are largely seeking to complete the projects in 2016 and bridge the period until the PPA begins by signing other, short-term contracts or by selling merchant power. As a result, the 2016 forecast has been increased, while the 2017-2018 forecast remains low.

Overall, the utility market is in the early stages of a second wave of new procurement, and we anticipate many new announcements of non-RPS projects over the coming year.

2.6. Installations by State and Segment, Q2 2014

Figure 2.32 U.S. PV Installations by State and Market Segment (MW_{dc})

	Q2 2014				Cumulative			
	Res.	Non-Res.	Utility	Total	Res.	Non-Res.	Utility	Total
Arizona	19.1	5.2		24.3	264.4	273.0	1,078.6	1,616.0
California	140.3	68.0	463.4	671.7	1,353.5	1,471.4	3,977.0	6,801.9
Colorado	9.0	2.4		11.4	113.3	139.5	106.6	359.4
Connecticut	0.8	2.7		3.5	27.3	47.4	7.4	82.1
Delaware	0.6	1.8		2.4	6.9	18.6	33.1	58.6
Florida	1.9	2.8		4.7	25.2	55.0	67.6	147.8
Georgia	1.0	1.3	7.2	9.5	3.2	26.1	109.0	138.4
Hawaii	14.1	7.3		21.3	209.4	145.0	27.4	381.8
Illinois	0.1	0.9		1.0	3.8	12.1	36.7	52.6
Indiana	0.1	1.5	14.2	15.9	0.6	4.2	75.9	80.8
Louisiana	3.4	0.1		3.5	43.6	1.6	0.0	10.6
Maryland	2.5	5.1		7.6	32.0	99.3	30.0	161.3
Massachusetts	9.0	87.4	15.8	112.1	74.5	432.4	74.1	581.0
Minnesota	0.0	0.3		0.3	2.8	10.3	2.3	15.4
Missouri	7.2	12.1	9.6	29.0	29.9	37.9	9.6	77.5
Nevada	0.3	3.5		3.8	8.9	51.0	355.7	415.6
New Hampshire	0.3	0.0		0.3	1.7	1.1	0.0	2.8
New Jersey	10.2	30.8	11.8	52.8	186.8	954.4	186.7	1,327.9
New Mexico	1.2	5.8	64.9	71.9	19.4	37.5	255.4	312.2
New York	11.9	9.7	1.0	22.6	94.9	144.3	55.8	294.9
North Carolina	0.9	0.5	33.7	35.1	11.1	98.4	517.2	626.7
Ohio	0.2	2.3		2.6	5.3	64.2	24.4	93.9
Oregon	1.5	0.3		1.8	27.7	35.6	15.8	79.1
Pennsylvania	0.4	1.0		1.4	50.7	165.5	21.6	237.8
Tennessee	0.3	0.2		0.4	7.9	49.5	18.1	75.5
Texas	2.8	2.0		4.8	34.8	32.3	151.2	218.2
Utah	1.3	0.7		2.0	9.1	11.7	0.0	18.2
Vermont	1.0	0.1		1.1	10.9	7.7	19.9	38.5
Virginia	0.4	0.1		0.5	2.3	5.8	0.0	8.1
Washington	2.7	0.1		2.8	21.9	8.4	0.0	30.3
Washington, D.C.	0.4	0.3		0.7	5.5	2.4	0.0	7.9
Wisconsin	0.2	0.3		0.5	6.2	10.7	1.1	18.0
Other	2.0	4.9	3.2	10.2	45.5	76.6	49.4	171.6
Total	246.9	261.5	624.9	1,133.3	2,741.1	4,530.8	7,307.5	14,542.3

2.7. Number of Installations

Figure 2.33 Number of U.S. PV Installations by State and Market Segment

	Q2 2014				Cumulative			
	Res.	Non-Res.	Utility	Total	Res.	Non-Res.	Utility	Total
Arizona	2,669	31		2,700	38,713	1,932	99	40,744
California	24,366	542	19	24,927	259,136	12,487	166	271,789
Colorado	1,390	23		1,413	19,799	1,682	7	21,488
Connecticut	104	15		119	4,233	376	1	4,610
Delaware	85	4		89	1,225	202	4	1,431
Florida	261	48		309	6,029	1,189	7	7,225
Georgia	19	17	18	54	440	278	114	832
Hawaii	2,611	125		2,736	45,237	2,176	7	47,420
Illinois	17	10		27	887	174	5	1,066
Indiana	18	34	2	54	100	60	7	167
Louisiana	544	3		547	4,024	35	-	1,660
Maryland	342	121		463	4,935	866	2	5,803
Massachusetts	1,383	87	5	1,475	12,054	1,782	27	13,863
Minnesota	6	6		12	481	313	1	795
Missouri	567	503	2	1,072	2,647	1,423	2	4,072
Nevada	41	32		73	1,637	644	10	2,291
New Hampshire	50	2		52	257	47	0	304
New Jersey	1,328	50	3	1,381	22,819	5,566	79	28,464
New Mexico	197	33	1	231	3,871	331	23	4,225
New York	1,595	126	4	1,725	14,559	2,983	21	17,563
North Carolina	173	14	7	194	1,916	264	140	2,320
Ohio	38	6		44	858	351	6	1,215
Oregon	284	13		297	7,223	643	6	7,872
Pennsylvania	82	39		121	6,944	2,314	4	9,262
Tennessee	39	8		47	630	573	9	1,212
Texas	475	38		513	6,006	777	18	6,801
Utah	246	32		278	2,378	93	0	838
Vermont	162	6		168	1,876	223	11	2,110
Virginia	87	5		92	1,465	195	0	478
Washington	432	9		441	4,355	263	0	4,618
Washington, D.C.	61	3		64	599	36	0	635
Wisconsin	35	11		46	1,244	474	1	1,719
Other	353	45	1	399	9,776	1,051	22	10,849
Total	40,060	2,041	62	42,163	488,353	41,803	799	525,741

2.8. Detailed Forecast Tables

Figure 2.34 Residential PV Installation Forecast, 2010-2018 (MW_{dc})

	2010	2011	2012	2013	2014E	2015E	2016E	2017E	2018E
Arizona	32	32	62	73	98	125	166	141	150
California	104	128	196	410	676	1,076	1,643	1,396	1,843
Colorado	19	14	18	28	42	53	70	65	74
Connecticut	3	3	6	7	10	15	22	16	25
Delaware	1	2	1	1	3	7	13	9	12
Florida	3	1	5	7	13	25	44	33	39
Georgia	0	1	1	0	4	10	20	14	17
Hawaii	8	21	57	83	65	51	70	64	79
Illinois	0	1	1	1	4	11	33	24	31
Indiana	-	-	-	0	2	4	9	7	10
Louisiana	-	-	-	21	24	29	35	28	34
Maryland	2	6	8	9	13	24	33	27	40
Massachusetts	2	5	15	30	40	55	72	68	80
Minnesota	1	0	1	0	4	6	12	8	10
Missouri	-	1	3	14	22	30	38	28	32
Nevada	1	1	0	1	5	16	26	20	30
New Hampshire	-	-	1	1	3	7	17	12	16
New Jersey	20	35	43	38	54	68	90	77	94
New Mexico	3	5	4	4	7	15	30	19	34
New York	12	8	15	27	62	90	140	176	225
North Carolina	0	2	1	2	7	16	34	18	37
Ohio	0	1	1	2	4	7	15	12	20
Oregon	4	4	6	6	8	14	23	16	29
Pennsylvania	14	17	7	10	6	12	22	18	23
Tennessee	-	1	3	2	5	6	8	7	10
Texas	3	5	8	9	18	31	55	52	63
Utah	-	0	0	1	4	12	19	9	14
Vermont	-	2	2	5	10	18	27	20	24
Virginia	-	-	-	2	4	10	19	16	19
Washington	2	3	3	8	11	15	24	19	22
Washington, D.C.	1	1	1	1	4	8	16	10	17
Wisconsin	1	2	0	1	6	10	17	12	15
Other	7	5	21	8	25	45	91	74	89
Total	246	304	494	814	1,263	1,921	2,954	2,515	3,258

Figure 2.35 Non-Residential PV Installation Forecast, 2010-2018 (MW_{dc})

	2010	2011	2012	2013	2014E	2015E	2016E	2017E	2018E
Arizona	22	76	64	58	66	60	74	62	70
California	90	216	307	293	360	465	690	620	710
Colorado	16	33	24	28	25	38	53	49	68
Connecticut	2	2	5	23	28	35	41	34	43
Delaware	2	8	2	1	8	13	20	15	19
Florida	5	5	14	19	13	19	31	23	35
Georgia	4	7	9	4	7	9	13	10	12
Hawaii	7	18	38	49	40	38	49	37	48
Illinois	0	1	4	1	7	12	23	16	19
Indiana	-	-	-	3	7	15	25	23	27
Louisiana	-	-	-	1	4	9	15	10	13
Maryland	5	16	41	20	31	41	53	44	57
Massachusetts	14	23	108	171	255	212	240	214	255
Minnesota	1	1	3	3	6	11	17	10	14
Missouri	-	3	4	14	35	26	38	28	36
Nevada	5	18	7	8	38	30	39	32	41
New Hampshire	-	-	1	1	3	8	13	9	12
New Jersey	89	226	300	189	196	262	400	365	444
New Mexico	5	4	4	14	17	24	37	30	39
New York	10	15	34	42	80	130	192	184	212
North Carolina	4	26	2	57	10	23	31	24	30
Ohio	7	20	13	17	14	10	16	12	17
Oregon	5	10	11	2	2	6	11	7	10
Pennsylvania	32	70	30	28	10	14	21	17	26
Tennessee	1	12	15	18	6	17	23	16	22
Texas	3	5	7	6	11	20	37	24	33
Utah	-	0	0	2	10	17	24	19	25
Vermont	-	3	2	2	4	7	12	8	11
Virginia	-	-	-	4	8	13	22	15	19
Washington	0	2	1	1	3	5	12	7	11
Washington, D.C.	0	1	0	1	3	6	10	9	14
Wisconsin	2	3	1	1	2	4	7	4	15
Other	6	6	23	26	30	46	65	48	110
Total	337	831	1,072	1,107	1,338	1,645	2,354	2,025	2,517

Figure 2.36 Utility PV Installation Forecast, 2010-2018 (MW_{dc})

	2010	2011	2012	2013	2014E	2015E	2016E	2017E	2018E
Arizona	9	182	592	290	166	315	154	38	48
California	22	233	542	1,918	2,177	2,048	3,342	401	501
Colorado	19	45	34	-	32	40	217	54	81
Connecticut	-	-	-	7	15	12	13	5	8
Delaware		11	15	7	-	5	-	-	-
Florida	27	8	5	-	10	55	159	56	95
Georgia	-	2	1	86	107	208	448	67	87
Hawaii	1	1	14	11	19	162	112	28	42
Illinois	10	-	26	-	18	23	-	-	-
Indiana	-	-	-	51	80	51	40	-	-
Louisiana	-	-	-	-	-	-	-	-	-
Maryland	-	-	30	-	22	20	-	-	-
Massachusetts	5	3	11	39	61	41	60	12	17
Minnesota	-	-	-	2	0	-	90	31	54
Missouri	-	-	-	-	10	20	-	-	-
Nevada	55	24	191	38	53	744	537	50	100
New Hampshire	-	-	-	-	-	-	-	-	-
New Jersey	24	52	76	9	70	68	113	23	32
New Mexico	35	114	15	26	108	55	76	26	45
New York	-	37	14	2	31	55	81	16	23
North Carolina	26	27	121	276	342	682	136	34	51
Ohio	12		11	1	18	6	-	-	-
Oregon	2	3	10	-	13	16	-	-	-
Pennsylvania	1	-	18	-	44	31	-	-	-
Tennessee	3	5	9	5	59	9	-	-	-
Texas	16	34	36	60	140	182	530	239	453
Utah	-	-	-	-	-	36	299	105	178
Vermont	-	-	8	9	12	10	-	-	-
Virginia	-	-	-	-	6	7	10	-	-
Washington	-	-	-	-	0	14	-	-	-
Washington, D.C.	-	-	-	-	-	-	-	-	-
Wisconsin	-	-	-	1	5	7	-	-	-
Other	2	3	25	16	291	237	497	174	296
Total	269	784	1,803	2,855	3,911	5,159	6,915	1,359	2,111

Figure 2.37 Total PV Installation Forecast, 2010-2018 (MW_{dc})

	2010	2011	2012	2013	2014E	2015E	2016E	2017E	2018E
Arizona	63	290	719	421	330	500	394	241	268
California	216	577	1,046	2,621	3,213	3,589	5,675	2,417	3,054
Colorado	54	92	76	56	99	131	340	168	223
Connecticut	5	4	11	37	53	62	76	55	76
Delaware	2	20	18	9	11	25	33	24	31
Florida	35	14	24	26	36	99	234	112	169
Georgia	4	10	11	91	118	227	481	91	116
Hawaii	16	40	109	144	124	251	231	129	169
Illinois	11	1	30	2	29	46	56	40	50
Indiana				54	89	70	74	30	37
Louisiana				22	28	38	50	38	47
Maryland	8	22	79	29	66	85	86	71	97
Massachusetts	22	31	134	240	356	308	372	294	352
Minnesota	2	2	4	6	10	17	119	49	78
Missouri		3	7	28	67	76	76	56	68
Nevada	61	44	198	47	96	790	602	102	171
New Hampshire			2	2	6	15	30	21	28
New Jersey	132	313	419	236	320	398	603	464	570
New Mexico	43	123	24	45	132	94	143	75	118
New York	23	60	63	72	173	275	413	376	460
North Carolina	31	55	124	335	359	721	201	76	119
Ohio	19	21	25	21	36	23	31	24	37
Oregon	11	18	27	7	23	36	34	23	39
Pennsylvania	47	88	54	38	60	57	43	35	49
Tennessee	3	18	27	25	70	32	31	23	32
Texas	23	44	51	75	168	233	622	315	549
Utah		0	1	2	14	65	342	133	217
Vermont		5	12	16	26	35	39	28	35
Virginia				6	18	30	51	31	38
Washington	3	5	4	9	14	34	36	26	33
Washington, D.C.	1	2	1	2	7	14	26	19	31
Wisconsin	3	5	1	3	13	21	24	16	30
Other	15	13	69	50	346	328	653	296	495
Total	852	1,919	3,369	4,776	6,512	8,724	12,223	5,899	7,885

2.9. National System Pricing

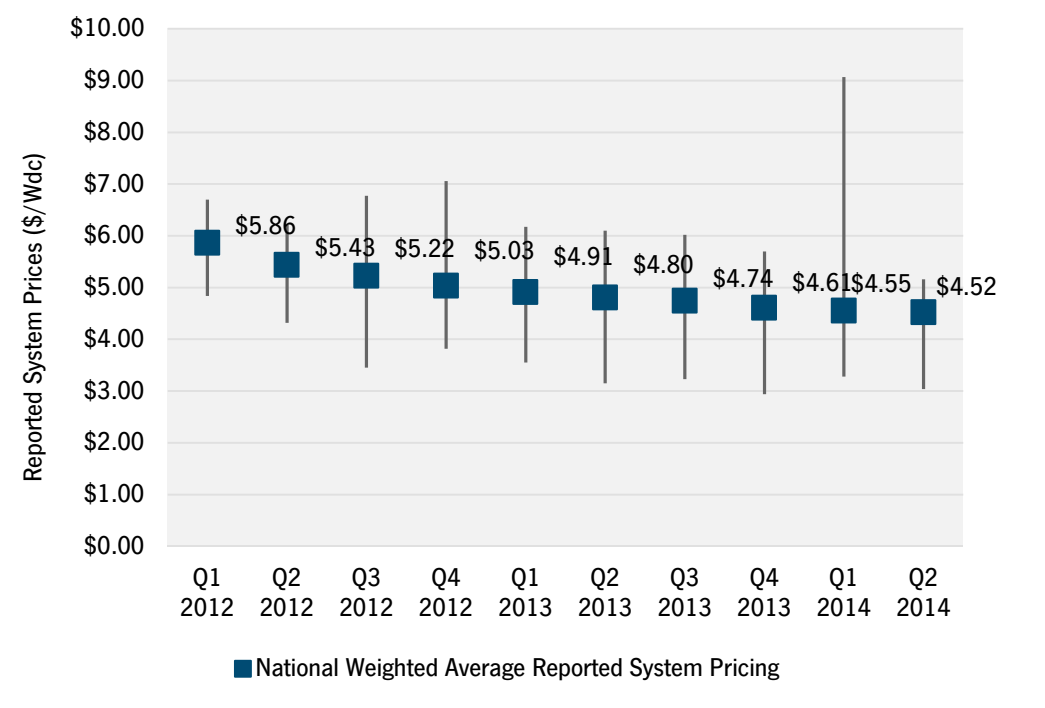
In the Q1 2014 edition of the *U.S. Solar Market Insight* report, we introduced a new methodology of capturing and reporting national system pricing. Our previous methodology used weighted average system pricing directly from utility and state incentive programs, but we have long felt that the data was not an ideal reflection of the current state of system pricing, as it often represented systems quoted in quarters well prior to the installation and connection date, and much of the reported data was based on fair market value assessments for TPO systems.

Our new bottom-up methodology is based on tracked wholesale pricing of major solar components and data collected from major installers, with national average pricing supplemented by data collected from utility and state programs. Starting with this report, we will no longer be reporting system prices state by state, although we will still continue to show reported national system pricing from state and utility incentive programs as a useful comparison with our bottom-up methodology.

2.9.1. National Residential System Pricing

Reported residential system pricing from state and utility incentive programs averaged to $4.52/W$_{dc}$ on a capacity-weighted average basis, with major state markets like California, Arizona and Hawaii reporting figures of $4.64/W$_{dc}$, $4.22/W$_{dc}$, and $4.28/W$_{dc}$, respectively. The lowest reported pricing came from programs in Florida ($3.04/W$_{dc}$) and Texas ($3.67/W$_{dc}$), whereas the highest reported pricing came from programs in Massachusetts ($5.16/W$_{dc}$) Minnesota ($4.79), Colorado ($4.74/W$_{dc}$) and Wisconsin ($5.68/W$_{dc}$).

Figure 2.38 Reported Capacity-Weighted Average Residential System Prices, Q1 2012-Q2 2014



As stated, these figures are subject to a number of factors that render the analysis insufficient for determining the actual industry costs during the quarter reported. These include:

- Various definitions of "cost" that may or may not be inclusive of fair market valuation and other components that do not necessarily reflect the true cost of solar installations
- Dated reporting of system pricing, reflecting quotes from as much as a year prior to the installation date
- Pricing for systems installed outside of state and utility incentive programs are not accounted for

As such, we have supplemented this reported data with more formal inquiries on system pricing put to major PV system installers and investors. In turn, our estimates for actual system pricing in the quarter lands at a considerably lower figure of $\$3.92/W_{dc}$. Higher-upfront-cost systems, such as those with microinverter technology, premium high-efficiency modules, or complex roof concerns, result in system pricing of around $\$4.75/W_{dc}$. Meanwhile, simple systems, especially with low levels of related soft costs (e.g., customer acquisition, permitting) can result in system pricing as low as $\$2.90/W_{dc}$.

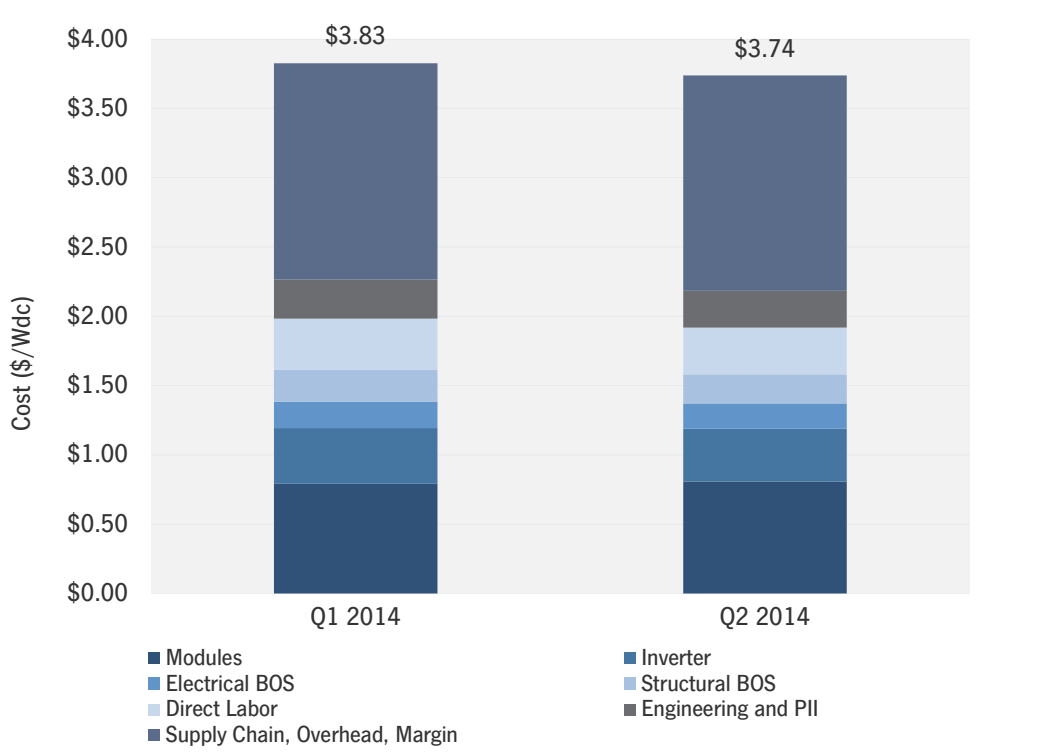
As a further step, we have built a bottom-up model of residential system costs that better elucidates component and categorical costs for PV systems built during the quarter. Due to the data sources for this information, these costs are more reflective of turnkey pricing on standard systems for firms installing a total of more than 1 MW (~150 systems) per quarter.

This quarter, we amend our residential cost breakdowns to reflect a blend of systems using microinverters and string inverters to hone in on a better "average" price.

System pricing continues to be pressured across the full value chain as residential incentives continue to decline and more competitors target slowing markets in states like Arizona and Hawaii. Our modeled costs show blended average national residential systems pricing at $\$3.74/W_{dc}$ in Q2 2014 versus the revised modeled costs for Q1 2014 of $\$3.83/W_{dc}$ – a 2.4% quarter-over-quarter cost reduction. In general, cost reductions were incremental and somewhat countered by a slight uptick in modeled PV module prices. As described in Section 2.11, structural balance-of-system costs continue to be one of the most heavily pressured hardware categories, with racking vendors indicating large volume purchases in the low- to mid-teens per watt.

Categories such as supply chain, overhead and margins, generally grouped as "soft costs," continue to be the largest cost category at $\$1.55/W_{dc}$, or 42% of total costs. These costs include substantial allocations for customer acquisition, distribution markups (often even medium-sized residential installers procure through distributors), and EPC margins, which even on their own would be significant contributors to the overall cost of the system. Other significant costs include the PV module and direct installation labor.

Figure 2.39 Modeled Residential Turnkey System Pricing With Cost Breakdown, Q1 2014-Q2 2014



U.S. Residential System Costs ($/Wdc)	Q1 2014	Q2 2014
Modules	$0.79	$0.81
Inverter	$0.40	$0.38
Electrical BOS	$0.19	$0.18
Structural BOS	$0.23	$0.21
Direct Labor	$0.37	$0.34
Engineering and PII	$0.28	$0.27
Supply Chain, Overhead, Margin	$1.56	$1.55
Modeled Average Turnkey System Price	**$3.83**	**$3.74**
Estimated National System Pricing	$3.98	$3.92
Reported National System Pricing	$4.55	$4.52

Note that large disparities in system pricing can be attributed to factors such as the size of projects, the size of the installation company, and what the local market will bear. In regions with high electricity retail rates, overall system pricing may be higher despite hardware costs that are similar to those in other regions. In terms of hardware costs, three major factors drive the variability:

- Premium PV modules, including high-efficiency modules, can command a 25% to 35% premium over standard-efficiency crystalline silicon modules

- Microinverters can add an 8% to 20% premium on the overall system due to additional hardware costs (although these are often offset by other installation cost improvements and performance benefits)
- Structural balance-of-system requirements, especially in high-wind zone areas or on clay tile roofs, can drive up the costs of materials and racking and mounting hardware by 50%

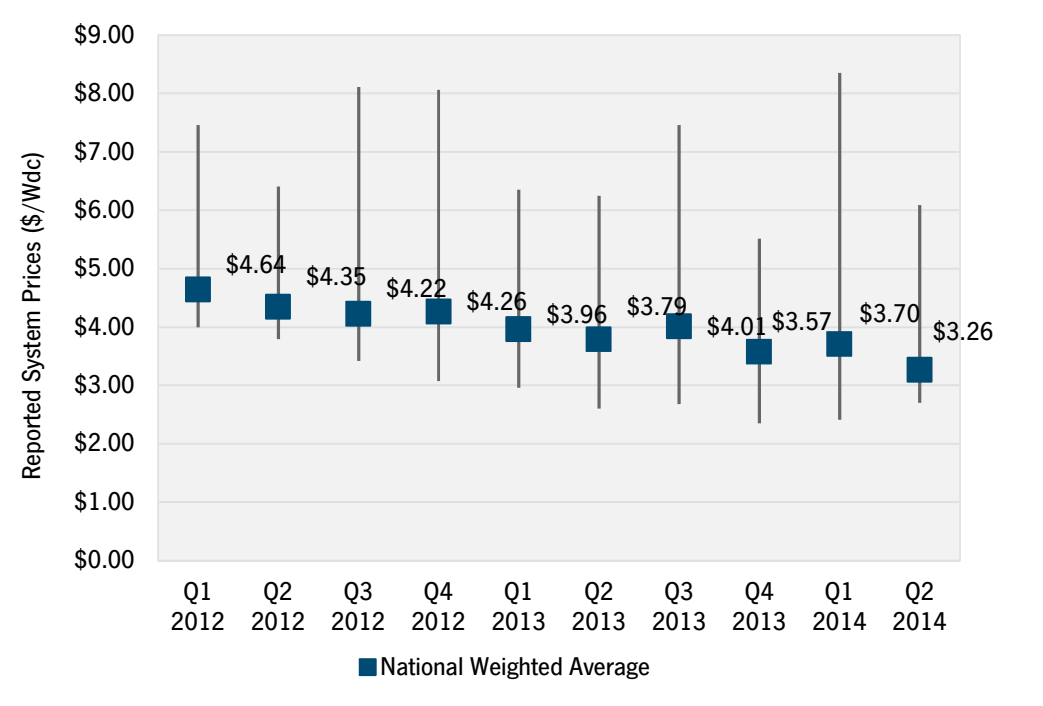
2.9.2. National Non-Residential System Pricing

Tracking non-residential system pricing presents an even greater challenge than tracking residential systems due to the significant variation in system sizes, customer types, and system types found in the non-residential sector. As one might expect, a 10 kW carport system for a small elementary school in Arizona will have a much different price point than a 5 MW ground-mount project on abandoned land in Massachusetts.

Reported system pricing from state and utility incentive programs averaged to \$3.26/W_{dc} on a capacity-weighted basis – a 12% drop from last quarter's reported average of \$3.70/W_{dc}. This drop is more reflective of the types and locations of non-residential projects installed in the quarter, rather than fundamental shifts in component and installation costs.

Reported weighted average system pricing in the major non-residential markets of California, New Jersey and Arizona came in at \$3.65/W_{dc}, \$3.03/W_{dc}, and \$3.73/W_{dc}, respectively. Wisconsin (\$2.72/W_{dc}) and Massachusetts (\$2.70/W_{dc}) were the lowest-priced markets in the quarter, whereas Minnesota (\$6.09/W_{dc}), Delaware (\$5.26/W_{dc}), and New York (\$4.68/W_{dc}) ranked as the highest-priced markets. (Note that in commercial markets, states with low volumes and states with incentive programs that limit the size of commercial projects will show higher-than-average commercial pricing.)

Figure 2.40 Reported Capacity-Weighted Average Non-Residential System Prices, Q1 2012-Q2 2014



Once again, reported pricing from major EPCs, integrators and developers indicates that standard construction costs in the quarter were lower than what was ultimately reported by state and utility agencies. Our estimates show that national capacity-weighted average system pricing in Q1 2014 was $2.97/W_{dc}$, with low pricing below $2.00/W_{dc}$. This represents an incremental 1.5% decrease in national-level system pricing. Again, this blend takes into account geographic and system-type variations across the country.

Some system characteristics that can drastically affect pricing include:

- Regional differences, in particular:
  - Weather-related building codes (e.g., snow and wind loading)
  - Labor pricing regulations (e.g., requirements for prevailing wage)
  - Building occupancy regulations (e.g., safety factors)
- System type (i.e., rooftop, carport, ground-mount)
- Customer type and electricity tariff structure

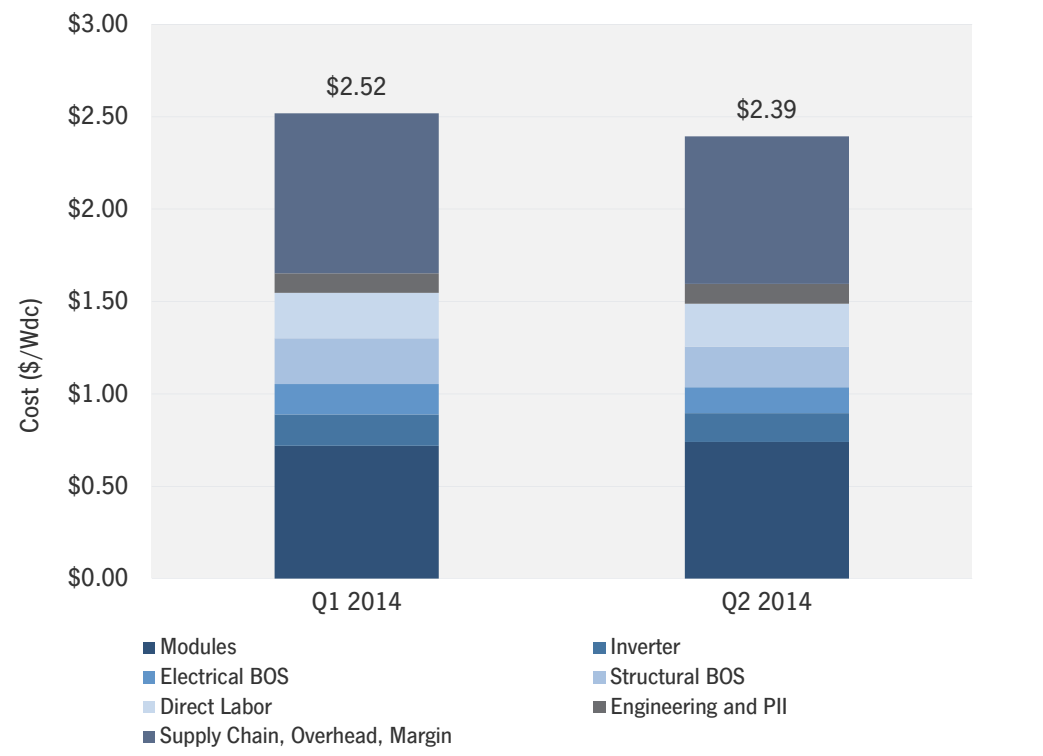
As with residential PV systems, we performed a bottom-up cost analysis of non-residential PV, specifically focusing on the example of a hypothetical ballasted flat-roof system sited in the Southwest U.S. Our inputs came from larger EPCs and integrators that likely have better-than-average pricing relative to the strict industry mean. In order to ensure that our bottom-up model reflects industry trends going forward, we have standardized around a minimalist flat-roof non-residential system, with the caveat that commonplace issues such as roof obstructions can significantly affect system costs. Our bottom-up model assumes:

- 300 kW low-slope ("flat") roof system
- Standard multicrystalline silicon PV modules
- String inverter-based design topology
- Fully ballasted, aluminum-based mounting structure
- Rectangular array on membrane roof
- PV module and inverters reflect "factory-gate" pricing with distribution and low volume markups reflected in the supply chain category

Our model shows flat-roof non-residential system costs at $\$2.39/W_{dc}$, representing a 5% decrease quarter-over-quarter. Note that our model this quarter reflects a string inverter-based commercial system versus the central inverter-based system modeled in the first quarter. This reflects a continued industry trend toward a decentralized PV architecture that is becoming standard practice in commercial rooftop and carport PV systems. Major cost declines come from inverter and structural BOS pricing – both challenged industries as the emergence of commoditization continues to compress margins. The potential for module pricing increases as the result of tariffs on Chinese and Taiwanese module products has also led to system developers and EPCs aggressively pushing for lower prices on other components and cost centers. For inverters, the switch to string inverters has also led to $\$0.01/W_{dc}$-$\$0.03/W_{dc}$ overall cost declines stemming from electrical balance-of-system material implications.

While considerably less than residential soft costs, commercial costs stemming from supply chain, overhead, and margins are similarly the single largest cost category at $\$0.80/W_{dc}$. Other significant costs to the system include the PV module (31% of total pricing) and direct installation labor (10% of total pricing).

Figure 2.41 Modeled Non-Residential Turnkey Rooftop PV System Pricing With Cost Breakdown, Q1 2014 – Q2 2014



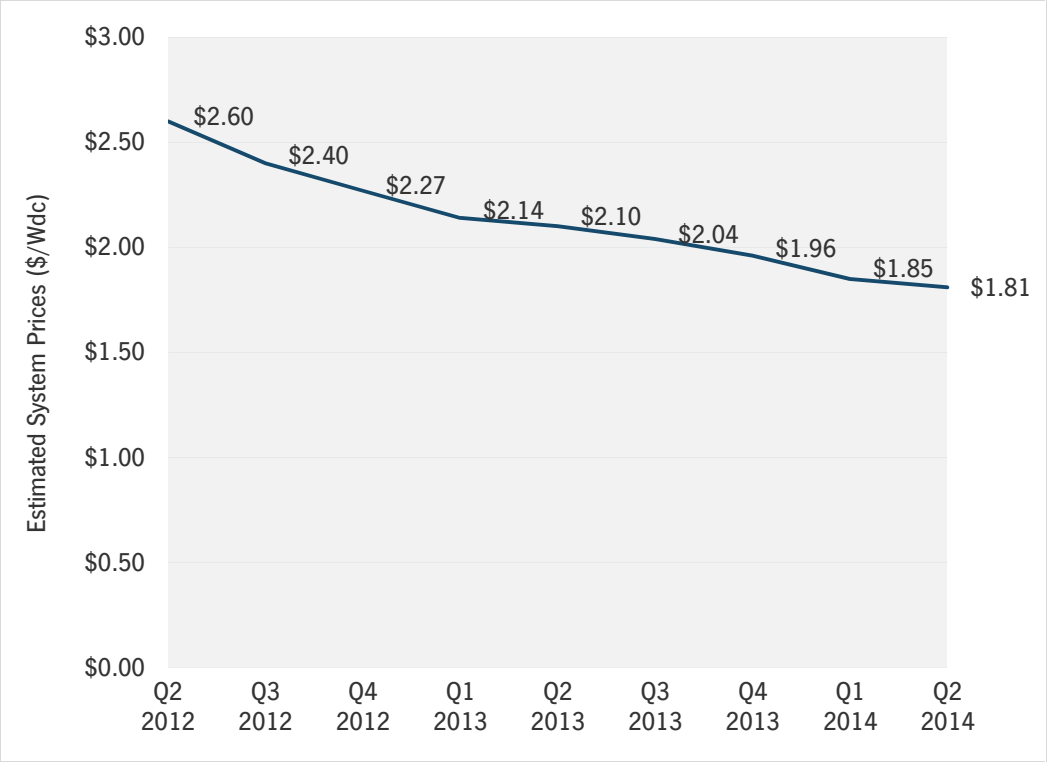
U.S. Non-Residential System Costs ($/Wdc)	Q1 2014	Q2 2014
Modules	$0.72	$0.74
Inverter	$0.17	$0.16
Electrical BOS	$0.16	$0.14
Structural BOS	$0.25	$0.22
Direct Labor	$0.25	$0.23
Engineering and PII	$0.11	$0.11
Supply Chain, Overhead, Margin	$0.87	$0.80
Modeled Turnkey PV Rooftop Pricing	**$2.52**	**$2.39**
Estimated National System Pricing	$3.02	$2.97
Reported National System Pricing	$3.70	$3.26

2.9.3. National Utility System Pricing

Unlike residential and non-residential systems, utility system pricing is rarely reported. As a result, our national capacity-weighted average incorporates publicly reported pricing where available, as well as input from utility developers and EPCs. National weighted-average system pricing for utility systems in Q2 2014 came in at $\$1.81/W_{dc}$, a 2.2% drop from Q1 2014, reflecting continued construction efficiencies and competition in the U.S. utility market. This estimate includes both tracking and fixed-tilt projects.

We also find that costs for systems installed in Q2 2014 came in as low as $\$1.60/W_{dc}$ and as high as $\$2.05/W_{dc}$. Low pricing reflects strong competition in new markets that has pushed component and EPC margins significantly downward. High pricing reflects systems with legacy PPAs and higher-cost components like single-axis tracking.

Figure 2.42 Capacity-Weighted Average Utility PV System Prices, Q2 2012-Q2 2014

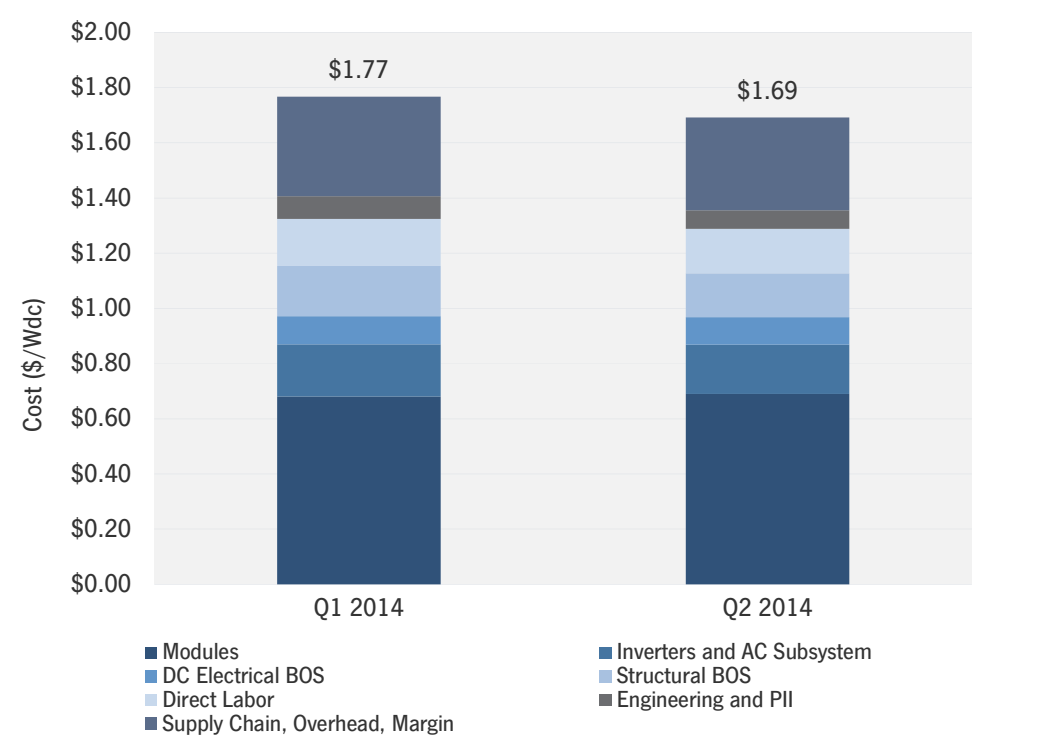


In modeling our utility PV system costs, we employ the following assumptions:

- 10 MW_{dc} utility system in the desert Southwest
- Standard multicrystalline silicon PV modules
- 1.3 DC-to-AC ratio
- Steel-based fixed-tilt system with pile-driven foundations
- Square array with minimal site grading
- PV module and inverters reflect "factory-gate" pricing

Modeled costs of a fixed-tilt utility system lands at $\$1.69/W_{dc}$, reflecting a 4.3% cost decline from last quarter's $\$1.77/W_{dc}$ pricing. Counter to other market segments, modules are the largest component cost in this segment, representing 41% of total system costs. Interconnection costs, especially substation build-out, are a major cost concern for project developers and can scuttle smaller utility projects if they are required. These costs are project-specific and are not included in the modeled costs below.

Figure 2.43 Modeled Utility Turnkey Fixed-Tilt PV System Pricing With Cost Breakdown, Q1 2014-Q2 2014



U.S. Utility System Costs ($/Wdc)	Q1 2014	Q2 2014
Modules	$0.68	$0.69
Inverters and AC Subsystem	$0.19	$0.18
DC Electrical BOS	$0.10	$0.10
Structural BOS	$0.18	$0.16
Direct Labor	$0.17	$0.16
Engineering and PII	$0.08	$0.07
Supply Chain, Overhead, Margin	$0.36	$0.34
Modeled Turnkey PV Fixed Tilt Pricing	**$1.77**	**$1.69**
Estimated National Turnkey Pricing	$1.85	$1.81

2.10. Manufacturing

2.10.1. Polysilicon

The global solar polysilicon industry is highly consolidated. This applies to the U.S. as well, where there are only three major facilities of note; each is individually owned by Hemlock, SunEdison, or REC. Together, these three facilities were responsible for 10,614 MT of solar polysilicon in the second quarter of 2014. This represented a 4% increase over production in Q1 2014 and a 16% increase over production in Q2 2013. The

significant year-over-year increase can be attributed to a much stronger pricing environment and a tighter overall supply-demand balance in 2014.

With no major capacity expansions planned for the U.S. in 2014 and factory utilizations for all U.S. facilities already high, room for production growth in 2014 is limited. Overall, output is expected to increase incrementally over the course of the year, likely peaking in the second half due to end-demand growth. 2015, however, could see significant capacity expansions in the U.S., with REC likely to add capacity in Washington and Wacker Chemie planning to commence operation of a new 15,000 MT facility in Tennessee.

Figure 2.44 U.S. Polysilicon Production, Q2 2013-Q2 2014

Polysilicon (Metric Tons)	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Quarterly Capacity	13,790	13,715	13,640	13,856	14,071
Production	9,157	10,207	10,778	10,318	10,614

2.10.2. Wafers

A total of 14 MW of wafers were produced in the U.S. in Q2 2014, which represents a 20% increase compared to last quarter's figure of 11 MW. Presently, there is only one active wafer manufacturing facility remaining in the U.S.: SunEdison's 180 MW monocrystalline plant in Oregon. Channel checks indicate that utilization levels at this plant have been low since 2011, and a large portion of the plant is used for R&D purposes. While SolarWorld maintains a 250 MW integrated ingot-to-module plant (also in Oregon), ingot and wafer production were discontinued, possibly permanently, in mid-2013.

Figure 2.45 U.S. Wafer Production, Q2 2013-Q2 2014

Wafer (MW)	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Quarterly Capacity	108	108	108	108	108
Production	38	11	16	11	14

2.10.3. Cells

Note: Thin film facilities producing modules through monolithic integration are not defined as producing cells in this report series.

U.S. crystalline silicon cell production was 130 MW in Q2 2014, representing a 7% increase quarter-over-quarter and an 11% increase year-over-year. For some time now, cell manufacturing in the U.S. has been confined to just two states: Oregon, where SolarWorld maintains a capacity of 500 MW, and Georgia, where Suniva's 170 MW plant is based. However, Texas will soon be an addition to this list, as new entrant Mission Solar Energy's 100 MW cell and module facility (focusing on high-efficiency n-type technology) came on-line in June and has ramped up production beginning Q3 2014.

Figure 2.46 U.S. Cell Production, Q2 2013-Q2 2014

Cell (MW)	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Quarterly Capacity	168	168	168	168	168
Production	117	126	132	122	130

2.10.4. Modules

Domestic module production in Q2 2014 amounted to 266 MW, 8% higher than Q1 2014 output and 8% above that of Q2 2013 as well. The year-over-year uptick was primarily due to healthier supply-demand balance in the global market compared to early 2013, as well as new trade litigation relating to imports of Chinese and/or Taiwanese produced cells and modules, which diverted a meaningful portion of sales to the best-positioned U.S. producers.

In terms of technology trends, the majority of modules produced in the U.S. in Q1 2014 were crystalline silicon (52%). With regard to thin film technologies, cadmium telluride (all First Solar) and CIGS (mostly MiaSolé and Stion) had a production share of 30% and 18%, respectively, leaving thin-film silicon with only a 4% share. Overall U.S. thin film production share stood at 48%, which is much higher than the global average (10% in 2013).

Figure 2.47 U.S. Module Production by Technology, Q3 2013-Q2 2014

Module (MW)	Q3 2013		Q4 2013		Q1 2014		Q2 2014	
	Capacity	Production	Capacity	Production	Capacity	Production	Capacity	Production
Crystalline Si	236	166	237	171	225	146	222	138
CdTe	78	70	80	72	84	63	100	80
CIGS	89	35	83	36	83	36	73	47
Thin-Film Si	6	1	6	1	6	1	6	1
Total	409	271	406	280	398	246	411	266

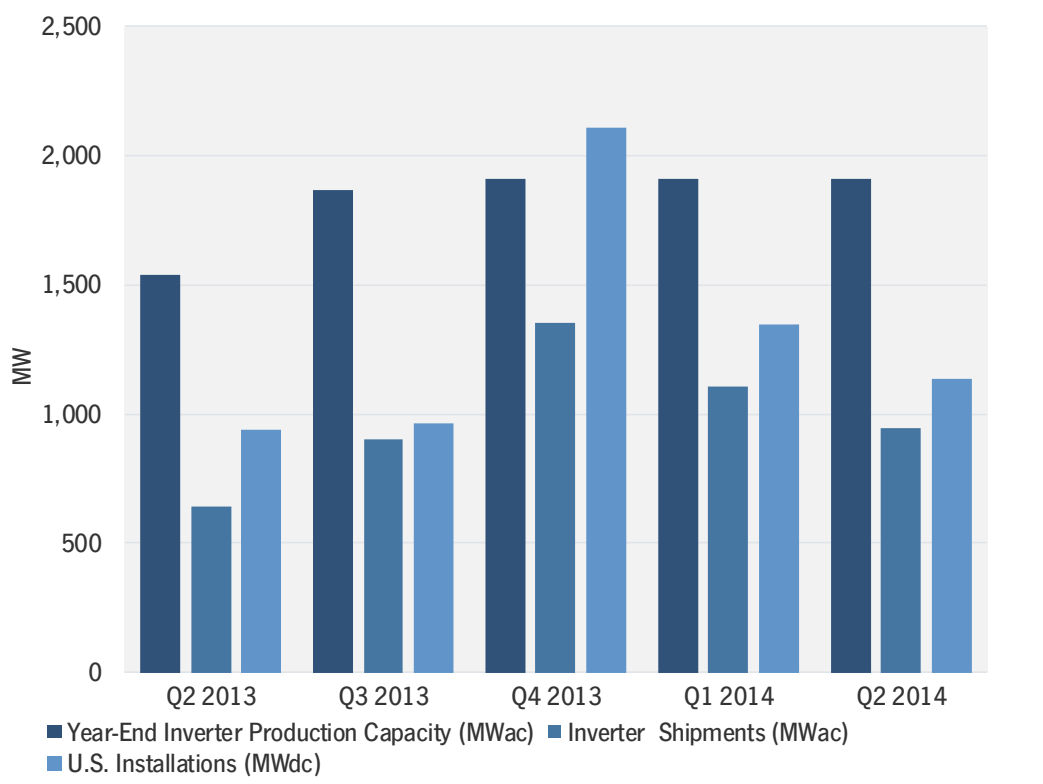
2.10.5. Inverters

In the second quarter of 2014, shipments of domestically produced inverters dropped to 945 MW_{ac}, primarily as the result of seasonal lag and decline in the utility segment. However, with a robust second half of the year expected for the U.S. commercial and utility markets, inverter production decline will be short-lived. Production capacity remained steady, although an announcement by a major inverter manufacturer indicates that significant U.S. inverter production capacity may be taken offline in favor of manufacturing in China.

Furthermore, the continued expansion of module-level power electronics (i.e., microinverters and DC optimizers) within the U.S. residential sector continues to cut into domestic production of inverters in the residential sector. This has been slightly countered by an expansion of the proportion of string inverters produced in the U.S., as well as two microinverter production facilities on the West Coast.

Year-over-year, the industry saw a significant 46% increase in inverter shipments, and if the growth between Q2 2013 and Q2 2014 is any indication, shipments of U.S.-produced inverters should well exceed the 1 GW mark again. Total reported production capacity in the U.S. remained steady at 1.9 GW, although we again note that offshoring of significant production capacity is expected by the end of the year.

Figure 2.48 Quarterly Domestic Inverter Capacity and Shipments (MW_{ac}) vs. Installations (MWdc)



	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Inverter Production Capacity (MW_{ac})	1539	1864	1908	1908	1908
Inverter Shipments (MW_{ac})	644	901	1351	1102	945
U.S. Installations (MW_{dc})	939	963	2108	1345	1133

The first half of the year saw many suppliers with supply chain disruptions due to new National Electric Code (NEC) 2014 rules surrounding "Rapid Shutdown" requirements aimed at improving PV safety on commercial buildings. These requirements are typically adopted piecemeal across the U.S. through state and local implementation and can be adopted well after revisions are released. For example, California is typically three years behind the most current code cycle. However, the growing importance of state markets outside of California, in conjunction with improvements in the streamlining of supply chains, led to a faster-than-expected adoption of inverters meeting the new code requirements. This has created some turmoil and some opportunities for inverter suppliers to win additional market share.

Meanwhile, Rule 21 standards in California that will dictate new regulations for PV system interconnection remain on hold. For the most part, the features being discussed, including power factor control, low-voltage ride-through (LVRT) and advanced monitoring, are not surprising to inverter manufacturers. These features have been on the table for years, first in European markets, and more recently in IEEE 1547 revisions. However, certification under the new standards is a concern both in terms of cost and time. As of the writing of this report, the three IOUs in California have submitted their recommendations for smart inverter setpoints,

largely in conformity with recommendations by the Smart Inverter Working Group (SIWG). The recommendations mandate the use of smart inverters when UL 1741 modifications are passed or by December 31, 2015, whichever is later. Smart inverters will be permitted before the mandated date as well.

2.11. Component Pricing

2.11.1. Polysilicon, Wafers, Cells, and Modules

Blended polysilicon pricing in the second quarter of 2014 increased by 2% quarter-over-quarter to $22.0/kg, while wafer pricing decreased by 4% to $0.23/W, mostly due to buildup of excess inventory in the early part of the year. Cell pricing also declined by 5% quarter-over-quarter to levels of $0.42/W, reflecting significantly lower demand for Taiwanese cells following new tariff rulings on imports of Chinese and Taiwanese solar products coming into the U.S. in the month of June.

Module pricing in the U.S. differs widely based on order volume, producer region and individual firm. Delivered prices for Chinese modules in Q2 2014 ranged from $0.67/W on the low side (corresponding to order volumes greater than 10 MW for less established firms) to $0.72/W on the high side (established, bankable firms, order volumes of less than 1 MW). Prices for European, U.S. and Japanese modules (selling mostly into the residential and small commercial sector) were notably higher at $0.78/W to $0.85/W. A few Taiwanese and Korean suppliers were offering pricing in between these two bands ($0.75/W to $0.80/W), albeit at limited volumes. Pricing for Chinese modules has increased in Q3 2014 due to the announcement of preliminary countervailing duties on Chinese modules and antidumping duties on Chinese and Taiwanese cells and modules, with quotes in mid-Q3 ranging from $0.73/W to $0.76/W. The most popular sourcing strategy currently being adopted by Chinese suppliers to mitigate cost increases from the new tariffs involves shipping all-Chinese product to the U.S. and paying the 2012 tariff on Chinese cell imports (30.7% for most firms).

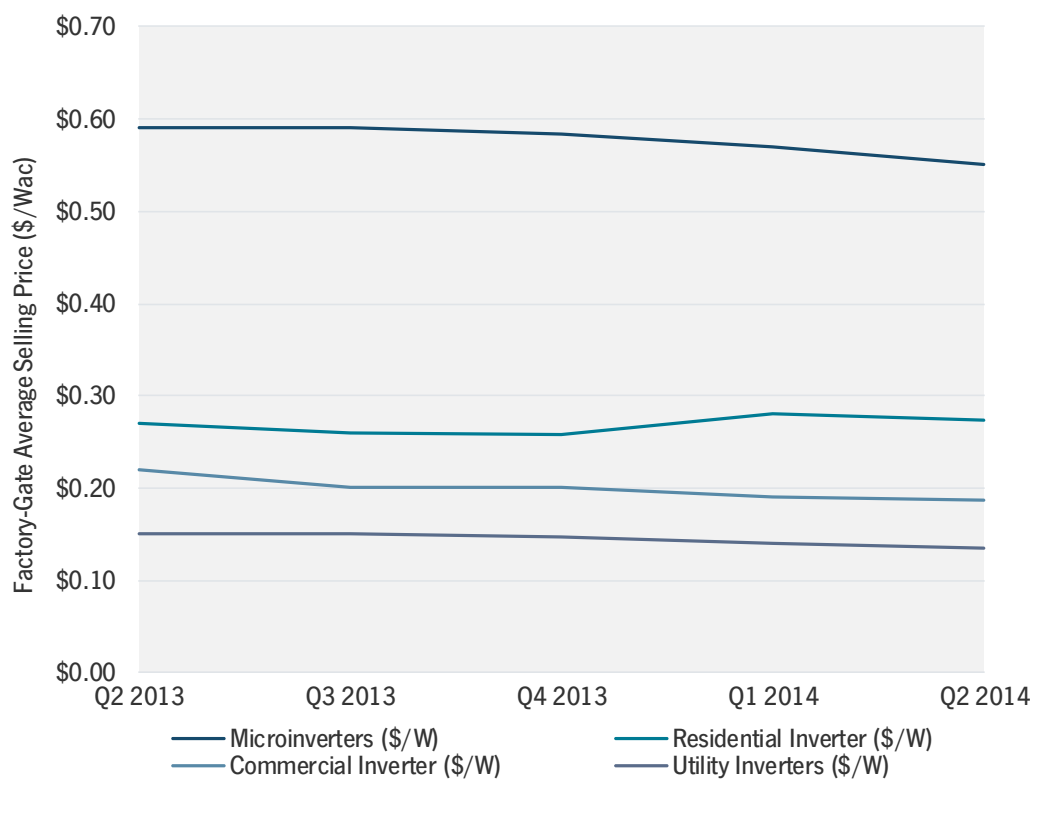
Figure 2.49 U.S. Polysilicon, Wafer, Cell, and Module Prices, Q1 2013-Q1 2014

	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Polysilicon ($/kg)	$19.00	$19.00	$20.20	$21.60	$22.00
Wafer ($/W)	$0.22	$0.22	$0.23	$0.24	$0.23
Cell ($/W)	$0.44	$0.42	$0.43	$0.44	$0.42
Module ($/W)	$0.68	$0.70	$0.72	$0.73	$0.73

2.11.2. Inverter Pricing

Factory-gate pricing remained relatively steady in the U.S., albeit with small declines in Q2 2014. Pricing in the U.S. remains higher than in European and Asian markets, but is reaching parity in the utility market. Interest from European and Asian competitors continues to pour into the market, especially in the central inverter category, and, more recently, in the string inverter segment.

Figure 2.50 Factory-Gate PV Inverter Pricing, Q2 2013-Q2 2014



National Average Pricing	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Microinverters ($/$W_{ac}$)	$0.59	$0.59	$0.58	$0.57	$0.55
Residential Inverter ($/$W_{ac}$)	$0.27	$0.26	$0.26	$0.28	$0.27
Commercial Inverter ($/$W_{ac}$)	$0.22	$0.20	$0.20	$0.19	$0.19
Utility Inverters ($/$W_{ac}$)	$0.15	$0.15	$0.15	$0.14	$0.14

2.11.3. Mounting Structure Pricing

The U.S. mounting structure market continues to experience heavy price pressures as module pricing has trended upward with the preliminary announcements of tariffs on Chinese and Taiwanese module products. This pressure continues to take its toll on mounting structure companies in the industry.

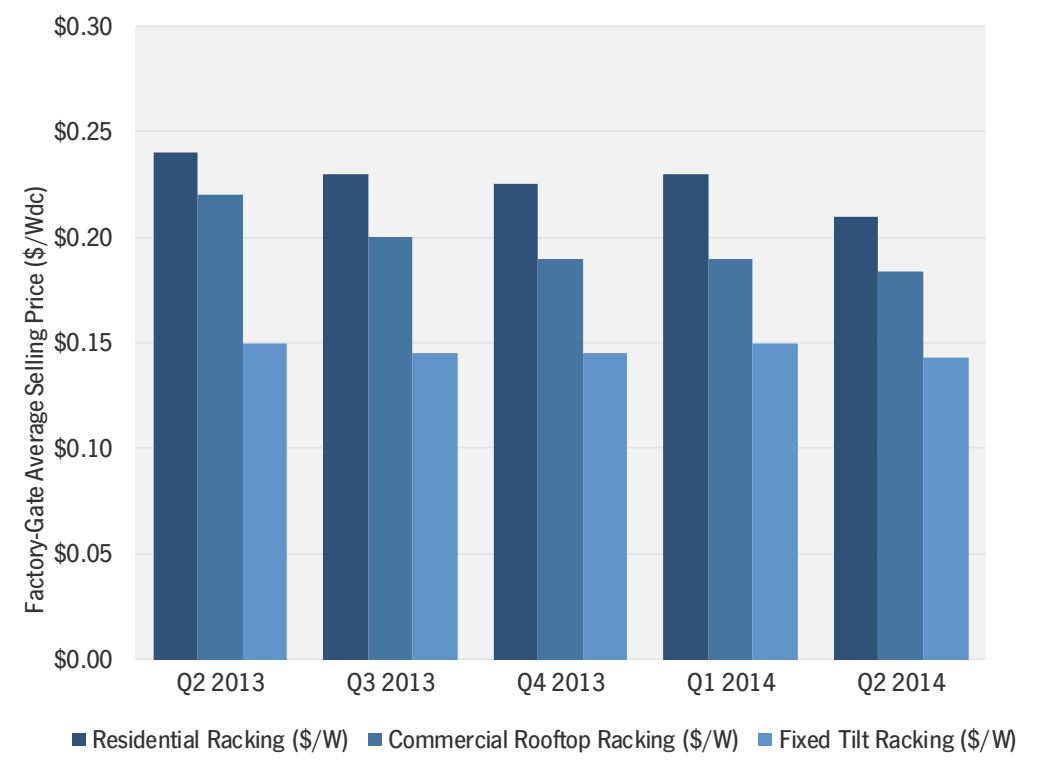
We continue to note that factory-gate pricing for PV mounting structures differs greatly depending on market segment, geography, configuration, layout and project size, all of which complicate the calculation of an "average" cost. For example, manufacturers reported costs in the second quarter for commercial rooftop systems anywhere between $0.14/W to $0.26/W. For simplicity's sake, we note that the values reported below reflect the mounting-structure-only costs of the following system types:

- **Residential rooftop:** 5 kW_{dc} to 10 kW sloped roof in California using a clamp-and-rail-based system

- **Commercial rooftop:** 100 kW to 500 kW flat-roof ballasted system in low wind areas requiring no additional structural support
- **Ground-mount fixed-tilt:** 1 MW to 5 MW fixed-tilt ground-mount system in low wind areas, not including foundation structures

Even with these baselines, note that PV mounting structure purchasers should consider the full implied cost of individual manufacturers rather than relying on quotes versus the national average. Differences in racking materials and design have different implications for labor costs, grounding requirements and the need for additional structural support. Note that we have revised our historical pricing in previous quarters given significant feedback that our values represented higher than market values.

Figure 2.51 PV Mounting Structure Prices, Q2 2013-Q2 2014



Average Price (National Aggregate)	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Residential Racking ($/W)	$0.24	$0.23	$0.23	$0.23	$0.21
Commercial Rooftop Racking ($/W)	$0.22	$0.20	$0.19	$0.19	$0.18
Fixed-Tilt Racking ($/W)	$0.15	$0.15	$0.15	$0.15	$0.14

3. Concentrating Solar Power

3.1. Introduction

In the U.S., concentrating solar thermal power plants experienced a burst of project activity in California in the 1980s and then remained largely inactive for two decades. But in the last few years, there has been an uptick of activity in this space, with an extensive list of CSP projects that are making steady progress. However, concentrating solar has not been immune to the turmoil of the larger solar industry, and the past few quarters have seen a number of CSP projects shelved or delayed.

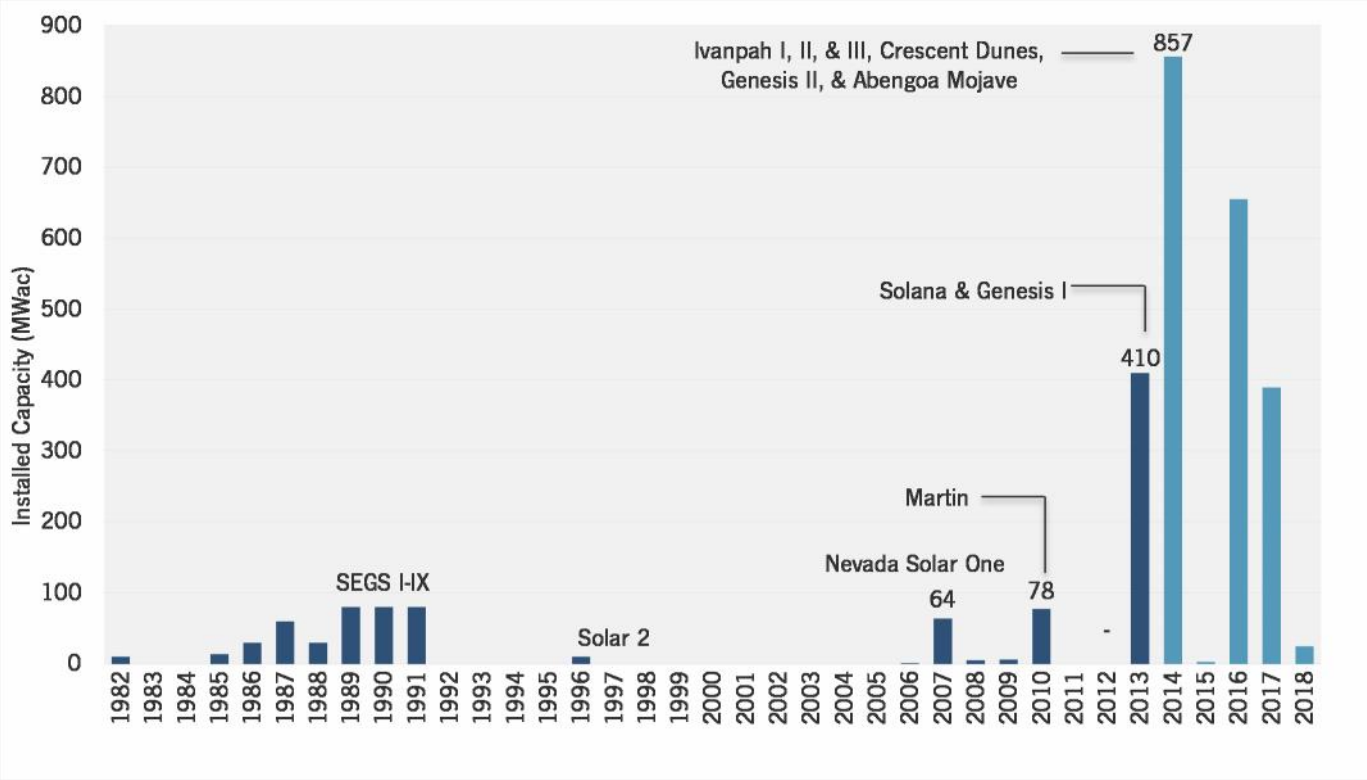
3.2. Installations

Figure 3.1 Concentrating Solar Installations, 2010-Q2 2014

Capacity Installed by State (MWac)	2010 Total	2011 Total	2012 Total	2013 Total	Q1 2014	Q2 2014	Cumulative
Arizona	2	-	-	280	-	-	283
California	-	-	-	125	517	-	1006
Florida	75	-	-	-	-	-	75
Hawaii	-	-	-	5	-	-	7
Nevada	-	-	-	-	-	-	64
Total	77	-	-	410	517	-	1,435

3.3. Installation Forecast

Figure 3.2 CSP Installation Forecast, 1982-2018E



As shown in Figure 3.2, the concentrating solar industry in the U.S. was effectively dormant from 1992 to 2006. In 2007, there was one project of scale: a 64 MW_{ac} trough plant in Nevada. Following that was the construction of several small demonstration plants for various technologies, including a 5 MW_{ac} compact linear Fresnel reflector (CLFR) plant in California in 2008, a 5 MW_{ac} tower plant in California in 2009, and a 1 MW_{ac} micro-CSP plant in Hawaii in 2009. The 75 MW_{ac} FP&L Martin Solar plant in Indiantown, Florida came on-line in the fourth quarter of 2010.

While the 5 MW_{ac} Kalaeloa Solar One project was the only concentrating solar power project to come on-line during the first three quarters of 2013, in Q4 the first wave of mega-scale CSP projects began to come on-line, starting with Abengoa's 280 MW_{ac} Solana Generating Station and the first 125 MW_{ac} phase of NextEra's Genesis solar project. Q1 2014 built on that momentum with 517 MW_{ac} brought on-line. This includes BrightSource Energy's 392 MW_{ac} Ivanpah project and the second and final 125 MW_{ac} phase of NextEra's Genesis solar project.

While Q2 2014 did not see much in terms of CSP activity, a total of 857 MW_{ac} is expected to be completed by year's end, making 2014 the largest year ever for CSP. The next notable project slated for completion is SolarReserve's 110 MW_{ac} Crescent Dunes, which entered the commissioning phase in February 2014. Major CSP project development highlights in Q2 2014 can be found in the following table.

Figure 3.3 Select Concentrating Solar Project Development Highlights

Project	Developer	State	Capacity (MW_{ac})	Expected Completion	Project Status Update
Crescent Dunes	SolarReserve	NV	110	2014	SolarReserve delayed completion target from December 2013 to early 2014; commissioning began in February 2014 and is expected to finish before the end of 2014.
Mojave Solar	Abengoa	CA	250	2014	Abengoa expects to begin commissioning of the project in Q3 2014.
Hidden Hills Solar	BrightSource Energy	CA	500	2017	The California Energy Commission agreed to BrightSource's request to suspend a review of the project for a second time until April 3, 2015.
Palen Solar	BrightSource Energy, Abengoa Solar	CA	200	2016	The California Energy Commission staff withdrew its proposal to reject conversion to solar power tower technology. Final decision to be released in October 2014.

Appendix A: Metrics and Conversions

Photovoltaics

We report PV capacity data in watts of direct current (DC) under standard test conditions (STC). This is the metric most commonly used by suppliers, developers and program administrators. However, some program administrators report data in alternating current (AC) watts, and some utility-scale systems are measured in AC watts. Given that, we assume an 87% DC-to-AC derate factor for systems of less than 10 MWac and a 77% DC-to-AC derate factor for systems greater than 10 MWac based on data from existing systems, conversations with installers, and averages from California Solar Initiative data.

Residential Photovoltaic System

A residential PV installation is defined as a project in which the offtaker of the power is a single family household. In addition, any PV system installed on a homeowner's property that participates in a feed-in tariff program is considered residential despite the fact that the offtaker of the power is a utility.

Non-Residential Photovoltaic System

A non-residential PV installation is defined as a project in which the offtaker of the power is neither a homeowner nor a utility. The spectrum of non-residential offtakers typically includes commercial, industrial, agricultural, school, government, and nonprofit customers. “Community solar" systems are also defined as non-residential. Although homeowners and apartment tenants unable to install solar are the typical subscribers of a community solar system, the fact that the system has multiple offtakers means that community solar systems fit the criteria for inclusion in the non-residential category.

Utility Photovoltaic System

A utility PV installation is a project in which the offtaker of the power is a utility or wholesale power market. This definition also includes any PV system installed on a non-residential customer's property that participates in a feed-in tariff program, in which the system's power is sold to a utility.

Concentrating Solar Power

We report CSP capacity data in watts of alternating current (AC), which is the metric most commonly used in the CSP industry. As a result, capacity comparisons for CSP and PV should not be considered on an apples-to-apples basis.

Appendix B: Methodology and Data Sources

Please note that data from previous quarters is sometimes updated as a result of improved or changed historical data.

Data for this report comes from a variety of sources and differs by data item, technology, and granularity. Below we outline our methodology and sources.

Historical Installations

PV: Quarterly state-by-state data on PV installations is collected primarily from incentive program administrators. These administrators include state agencies, utility companies, and third-party contractors. For larger projects not included in these programs, GTM Research maintains a database that tracks the status of all operating and planned utility PV projects in the United States. In some cases, program administrators report incentive application and award dates rather than installed dates. In these instances, we use the information that most closely approaches the system's likely installed date. For annual and cumulative installations prior to 2010, 2010 data for "Other States" and smaller utilities, GTM Research also utilized data collected by Larry Sherwood at the Interstate Renewable Energy Council (IREC).

CSP: GTM Research maintains a database that tracks the status of all operating and planned CSP projects in the United States.

PV	State incentive program administrators, utility companies, state public utilities commissions, PUC filings, GTM Research Utility PV Project Database, Larry Sherwood/IREC
CSP	GTM Research CSP Project Database, announcement tracking, state public utilities commissions, conversations with developers/manufacturers

Average System Price

PV: Prior to Q1 2014, the methodology used to estimate average system prices was based on weighted-average system pricing received directly from utility and state incentive programs, but GTM Research and SEIA have long felt that the data was not an ideal reflection of the current state of system pricing, as it often represented systems quoted in quarters well prior to the installation and connection date, and much of the reported data was based on fair market value assessments for TPO systems.

As of Q1 2014, GTM Research and SEIA have switched to a bottom-up methodology based on tracked wholesale pricing of major solar components and data collected from major installers, with national average pricing supplemented by data collected from utility and state programs.

PV	GTM Research manufacturing facility databases, announcement monitoring, conversations with manufacturers
CSP	Announcement monitoring, conversations with manufacturers

Components in the national cost breakdown categories include:

- PV module: national average delivered pricing for Chinese crystalline silicon modules
- PV inverters: national average factory-gate pricing with product as specified in the respective breakdown sections
- Electrical balance of systems ("EBOS"): includes all additional electrical components necessary for the system, including DC and AC wiring, system and equipment grounding, conduit, disconnects, fuses, circuit breakers, and data monitoring
- Structural balance of systems ("SBOS"): includes all additional equipment necessary to support the PV system structurally, including mounting systems, foundations, ballast, racking, and clamps
- Direct labor: Includes all the necessary labor related to PV system installation including site setup/preparation, installation, in-field logistics, and system commissioning
- Engineering, design, permitting, interconnection, inspection: Includes all labor and fees not directly related to preparing or installing PV system, including system engineering, design, permitting inspection and fees, interconnection labor and fees, and project management
- Supply Chain, Logistics, Customer Acquisition, Overhead and Markup: Includes all other costs directly associated with the project, including supply chain costs (distribution markups, volume markups, taxes); logistics (shipping and handling); customer acquisition (direct sales and marketing, site visits); overhead (project-related office costs) and markup (margin).

Manufacturing Production and Component Pricing

GTM Research maintains databases of manufacturing facilities for PV and CSP components.

PV	GTM Research manufacturing facility databases, announcement monitoring, conversations with manufacturers
CSP	Announcement monitoring, conversations with manufacturers

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