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US Solar Market Insight

Full report

Q2 2025

About the report

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US Solar Market Insight® is a quarterly publication of Wood Mackenzie and the SEIA®. Each quarter, we collect granular data on the US solar market from nearly 200 utilities, state agencies, installers, and manufacturers. This data provides the backbone of this US Solar Market Insight® report, in which we identify and analyze trends in US solar demand, manufacturing and pricing by state and market segment over the next five to 10 years. All forecasts are from Wood Mackenzie, Limited; SEIA does not predict future pricing, bid terms, costs, deployment or supply. The report includes all 50 states, Washington, DC, and Puerto Rico. Detailed data and forecasts are contained within the full version of the report.

References and Contact

- **References, data, charts, and analysis from this executive summary should be attributed to "Wood Mackenzie/SEIA US Solar Market Insight®."**
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- **All figures are sourced from Wood Mackenzie. For more detail on methodology and sources, access the full report at http://www.woodmac.com/research/products/power-and-renewables/us-solar-market-insight/.**

Note on US Solar Market Insight report title: The report title is based on the quarter in which the report is released, not the most recent quarter of installation figures.

Contents

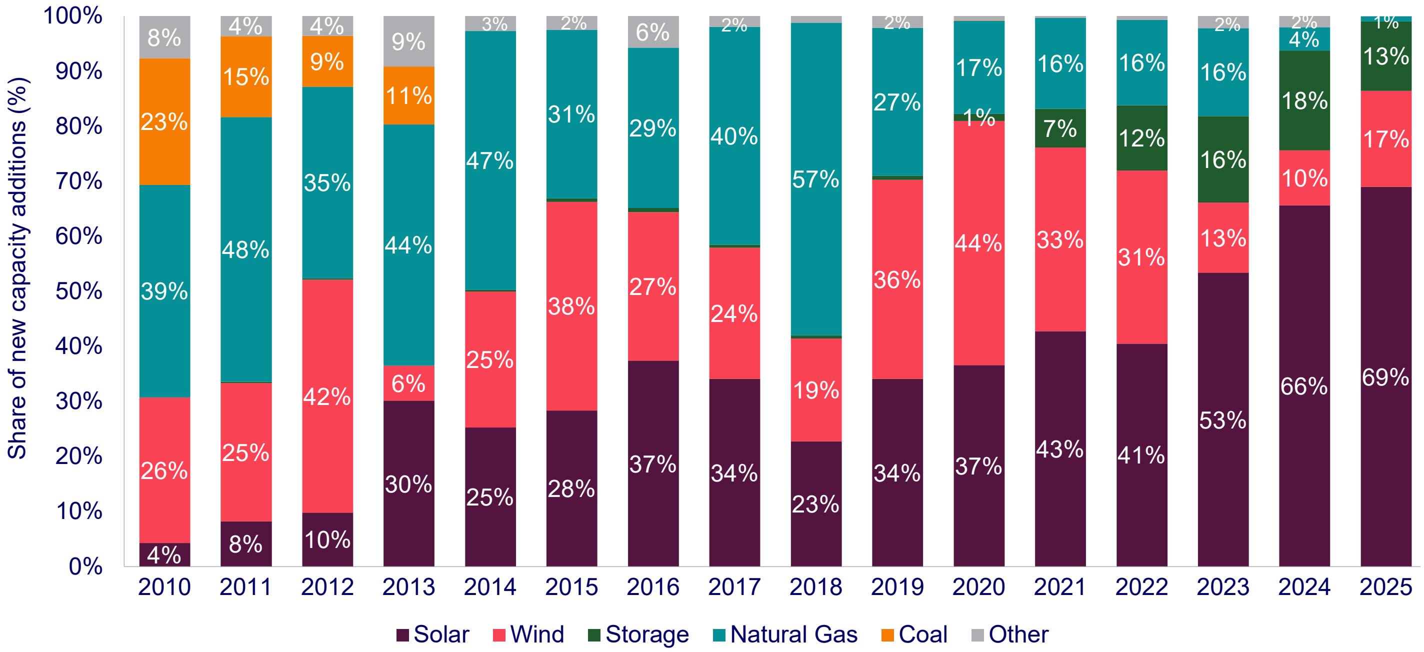
1. Introduction

The US solar industry installed 10.8 gigawatts-direct current (GW_{dc}) of capacity in the first quarter of 2025. Despite both a quarterly and annual decline in capacity, Q1 2025 was the industry's fourth-best quarter. The utility-scale segment followed a similar trend, with 9 GW_{dc} of capacity, which is lower than both Q1 2024 and Q4 2024. However, Q1 2025 still ranks among the segment's top quarters ever. Sixty-five percent of the quarterly utility-scale installations were concentrated in five states: Texas, Florida, Ohio, Indiana and California.

The distributed solar segments showed mixed performances last quarter. Commercial solar grew by 4%, installing 486 MW_{dc}, making it the only solar segment to increase compared to Q1 2024. California's NEM 2.0 installations continued to fuel the commercial segment, with the state adding more than 200 MW_{dc} in Q1. Community solar installations, however, dropped significantly to 244 MW_{dc} after a massive fourth quarter. A net metering deadline in Maine led to a surge in installations at the end of 2024, followed by a dramatic drop in Q1. New York continued to lead the way for community solar installations with more than 100 MW_{dc}. Residential solar installed capacity reached its lowest point since Q3 2021, with 1,106 MW_{dc} added last quarter. While the first quarter typically sees slower residential installations, the segment continues to face numerous headwinds, including consumer hesitancy to go solar due to economic uncertainty, tariffs, and the availability of the residential solar investment tax credit (ITC).

Overall, photovoltaic (PV) solar accounted for 69% of all new electricity-generating capacity additions in the first quarter of 2025, remaining the dominant form of new electricity-generating capacity in the US.

New US electricity-generating capacity additions, 2010 – Q1 2025



Source: Wood Mackenzie, note that starting with the Q2 2024 report, capacity additions for the solar, wind, and storage technologies are sourced from [Wood Mackenzie data] while all other technologies are sourced from the US Energy Information Administration.

The solar industry faces a perfect storm of Federal policy challenges

The US solar industry faces significant policy headwinds due to multiple recent federal actions. The proposed House budget reconciliation bill, passed by the House on May 22, would, if enacted, eliminate the residential tax credits for both customer-owned and third-party owned lease projects starting in 2026. Section 48E (utility-scale, commercial & industrial, and community solar) projects would have to start construction within 60 days of enactment and be placed in service by the end of 2028 (or the end of 2025 for residential third-party financed systems). While this bill passed the House by one vote, it must now make it through the Senate, where any changes would require the House and Senate to work out a compromise.

Additionally, the bill proposes eliminating electric vehicle tax credits and hydrogen production credits after 2025, as well as imposing prohibitively complex "foreign entity of concern" restrictions that could effectively make the credits unusable in short order. The change from "start of construction" to "placed in service" requirements for tax credit eligibility adds further complexity and risk for developers, as does the elimination of tax credit transferability after 2028. However, many of those points are largely moot, given the short timeline available to begin construction. Likewise, the bill cuts other funding, much of which spending freezes are already holding up.

Furthermore, the executive order to "reinvigorate America's beautiful clean coal industry" signals a stark pivot in federal energy priorities. By elevating fossil fuels and critical minerals while excluding solar, wind and storage from the definition of energy resources, this order aims to accelerate the production of coal, oil, natural gas and uranium. Such a reorientation of federal policy could redirect funding and regulatory support away from solar and towards conventional energy sources, though none of these actions are likely to remedy the gas turbine shortage over the next five years.

Trade-action whirlwind exacerbates uncertainty

The US solar industry faces a complex and evolving trade landscape that will significantly impact development over the next five years. The flurry of recent trade actions, both industry-specific and non-industry-specific, is reshaping the economics of solar projects and supply chains.

The Trump administration implemented significant trade policy changes in Q1 2025 by modifying and introducing new tariffs. Initially set to take effect in February, a 25% duty was imposed on imports from Canada and Mexico starting March 4, with exceptions for goods under the USMCA trade agreement and a 10% limit on Canadian energy resources and critical minerals. Modifications to Section 232 duties on all imports of steel and aluminum articles followed this action. The new scope of Section 232 removed country exemptions and terminated the exclusion process for steel and aluminum imports; it also equalized the aluminum tariff rate by increasing the duty from 10% to 25% (most recently increased to 50% on June 4). Although the US solar industry doesn't materially import assembled equipment from Canada or Mexico, these tariffs have an indirect impact on the sector. Some components used in the production of inverters and trackers are sourced from these countries, effectively raising production costs for US manufacturers. Notably, despite the US solar industry's reliance on domestically produced steel, market forces triggered an immediate increase in the domestic steel index. This unexpected rise has increased the production costs of tracker manufacturers, potentially affecting project economics. Additionally, US module manufacturers face increased frame costs.

Tariffs on Chinese goods underwent significant fluctuations throughout early 2025 as the administration imposed and modified fentanyl-related and reciprocal tariffs, creating a volatile trade environment. With a 10% fentanyl-related tariff effective on February 4, the duties escalated rapidly, reaching 20% by March 4, then surging from 54% following the imposition of reciprocal tariffs to 104% effective April 9, before peaking at 145% effective on April 12. Chinese and US officials' joint announcement of a 90-day tariff rollback agreement interrupted this upward trajectory on May 12. The resulting tariff structure, effective May 14, comprised a 10% general duty plus a 20% fentanyl-related duty, totaling a 30% tariff that can stack on top of other tariffs (e.g., Section 201, Section 301, AD/CVD). As of May 29, two courts have ruled that the statutes cited by the President do not grant the authority to issue these broad tariffs, thereby adding to the volatility and business uncertainty. However, a federal appeals court subsequently paused their ruling.

While the US solar industry doesn't significantly rely on equipment imports from China, these frequent tariff adjustments have introduced considerable uncertainty into the market. The growth of the solar industry also depends on the development of storage resources. Swings in tariff policy toward China introduce volatility to storage costs, due to China's significant share of the battery manufacturing market. This turbulence may impact supply chain strategies, potentially influencing sourcing decisions and risk assessments for developers and investors. In particular, domestic manufacturers may have to pay increased costs for specific manufacturing equipment and components that are difficult to source from outside China.

More broadly, the "Liberation Day" announcement on April 2 introduced sweeping new tariffs aimed at addressing perceived longstanding "unfair trade practices" and stimulating domestic manufacturing. This policy overhaul, the most significant since the 1930s, implemented a universal 10% tariff on all imports effective April 5 for goods not loaded onto a vessel and in transit. Country-specific duties followed. They range from 10% to 49% effective April 9 for goods not loaded onto a vessel and in transit. Notably exempted were imports from Canada and Mexico, as well as goods already subject to Section 232 tariffs, select energy products, and certain critical minerals. The implementation timeline was adjusted on April 9, with President Trump announcing a 90-day pause on most country-specific reciprocal tariffs while maintaining the universal 10% duty and China-specific duties (up until the May adjustment).

This new tariff structure could have significant implications for the US solar industry, which relies on international sourcing. Unless country-specific duties are renegotiated before the tariff pause ends, key countries for the industry now face substantial tariffs: Thailand (36%) and India (26%) for inverters; Laos (48%), Indonesia (32%), South Korea (25%), and Malaysia (24%) for cells and modules (polysilicon and wafers are notably exempted). These duties would be applied in addition to the existing AD/CVD and Section 201 tariffs. These tariffs may reshape dynamics in the solar sector's supply chain. The industry may experience increased costs and potential supply constraints in the short term, with longer-term implications for project economics and competitiveness.

Adding to this complexity, on April 20, the Department of Commerce (DOC) issued its final determination in the anti-dumping and countervailing duties (AD/CVD) investigation on solar cells and modules. The ruling set cumulative duty rates ranging between 14.64% and 3,500% for manufacturers from Cambodia, Malaysia, Thailand, and Vietnam (CMTV), exceeding the preliminary determination levels. This decision has introduced significant uncertainty for developers who have historically relied on imports from these countries. On May 20, the International Trade Commission issued a final affirmative injury decision. It will trigger a resumption of AD/CVD duty collection at final rates when the *Federal Register* publishes the final ITC report.

Although the final decision was only recently issued, there have been some shifts in solar imports. Specifically, module import patterns have already started to change, while cell import trends have yet to undergo significant shifts. Module imports from CMTV have plummeted from an average of 3.8 GW per month in 2024 to an average of 1.1 GW per month in Q1 2025. Module imports from Cambodia, whose mandatory respondents withdrew from participation in the AD investigation and received the highest company-specific and country-wide AD/CVD rates, have dropped to 0 GW in 2025. Concurrently, we have observed an increased presence of alternative sourcing locations in the US module import mix. For example, the share of module imports from Indonesia and Laos has grown to 34.6% in Q1 2025. The solar industry continues to be nimble, but the rapid proliferation of trade action poses potential challenges in maintaining a steady supply and managing costs. We expect these shifts to continue influencing project economics and development timelines through 2026, with possible long-term implications for the US solar manufacturing landscape.

For utility-scale solar, which is particularly sensitive to equipment costs, trade action could slow deployment in the next 1-2 years as developers navigate higher prices and supply chain disruptions. We anticipate some projects may be delayed or canceled, especially those with tight margins or fixed power purchase agreement prices that are harder to renegotiate.

The cumulative effect of these policy changes creates a challenging and uncertain environment for solar development over the next five years. While underlying demand drivers such as imminent load growth and corporate sustainability goals remain strong, the industry will need to navigate a complex policy landscape with potentially reduced federal support. State-level initiatives and corporate demand will gain more relevance in driving solar growth, partially offsetting federal headwinds. The industry's ability to adapt to this shifting policy terrain will be crucial in determining the pace of US solar deployment through 2030 and beyond.

The US solar market will add more than 250 GW_{dc} by 2030 in our Base case, but there is a downside risk

Federal policy and trade action present significant challenges and uncertainty for the US solar industry. Our five-year Base case outlook incorporates the latest effective tariff announcements as of this report's publication date. In addition to the 25% tariffs on Canada and Mexico, we assume settlement of tariffs over the next 90 days, including a 30% tariff rate for China in 2025 and 2026, and a 10% rate for all other countries. However, our outlook does not reflect the provisions in the House budget reconciliation bill.

While tariffs will not significantly impact solar installation volumes this year, more immediate headwinds will lead to declines in all segments in 2025. Residential installations will decrease slightly in 2025, following a 30% market contraction in 2024, as high interest rates and other market headwinds impact consumer demand. Commercial solar capacity will fall by 4% this year compared to 2024, as the backlog of California NEM 2.0 installations is depleted and growth slows in other mature markets such as Maine, New Jersey, and New York. The community solar market will experience a more significant contraction, with capacity declining by 22% year-over-year in 2025, following a record year in 2024. Lastly, utility-scale installations will drop by 2% in 2025 after two solid years of growth. Policy and tariff uncertainty are resulting in a contraction in the segment's pipeline, impacting near-term growth.

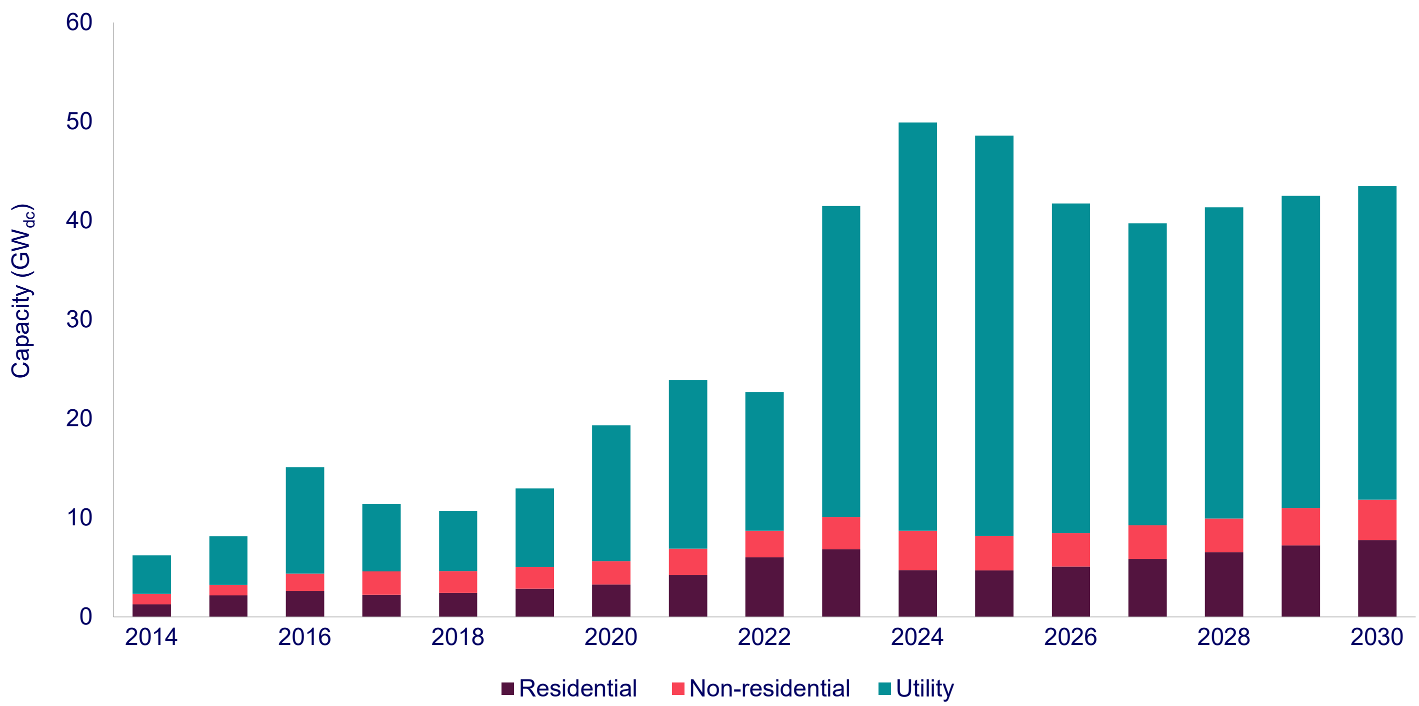
The US solar industry is projected to contract by 2% annually between 2025 and 2030 in our Base case but still add nearly 43 GW_{dc} on average each year. In the near term, solar installations will decline at an average rate of 7% from 2025 to 2027.

Policy uncertainty and rising costs due to tariffs will impact market growth across all solar segments. Proposed tax credit changes and stricter regulations on foreign entities could also result in a more significant market contraction.

Industry growth will resume in the second half of our outlook, with solar installations projected to increase by 3% between 2028 and 2030. The solar industry's supply chain shifting domestically and increased energy demand from AI and data centers are driving this recovery. However, labor shortages and interconnection delays will continue to hinder growth.

It is important to note that the power industry backdrop in which solar competes will have a substantial impact on its trajectory. Wood Mackenzie is now tracking nearly 140 GW of proposed data centers, up from approximately 50 GW a year ago. Moreover, reshoring of manufacturing in clean energy and other industries presents additional large-load facilities that will increase electricity demand. With supply chain constraints on gas turbines and the escalating cost of constructing new gas plants, solar will play a vital role in helping to meet demand growth.

US solar PV installations and forecasts by segment, 2014-2030



Source: Wood Mackenzie

State solar PV installation rankings, Q1 2025

	Rank			Installations (MW_{dc})		
State	**2023**	**2024**	**Q1 2025**	**2023**	**2024**	**Q1 2025**
Texas	1	1	1	11,979	10,854	2,659
Florida	3	3	2	3,223	4,856	1,388
California	2	2	3	6,567	4,883	1,011
Ohio	6	5	4	1,263	2,432	886
Indiana	15	9	5	679	1,631	661
Arizona	5	6	6	1,527	1,793	534
Illinois	13	4	7	835	2,798	486
Wisconsin	9	16	8	961	801	353
Idaho	27	36	9	251	175	266
Pennsylvania	12	19	10	853	565	229
Connecticut	35	34	11	188	183	220
Kentucky	40	24	12	99	397	209
Oregon	21	41	13	374	101	206
Virginia	7	13	15	1,134	1,508	192
Arkansas	18	8	16	447	1,649	188
New York	10	7	14	931	1,662	200
Michigan	16	23	17	555	501	173
Louisiana	26	15	18	300	905	140
Oklahoma	44	30	19	46	203	138
Puerto Rico	17	26	20	464	337	97
Missouri	38	22	21	112	542	75
New Jersey	19	28	22	429	300	53
Hawaii	25	32	23	300	196	53
Massachusetts	22	27	24	348	314	48
Colorado	4	25	25	1,656	375	37
Nevada	8	10	26	962	1,598	34
Maine	20	18	27	393	736	34

Source: Wood Mackenzie

State solar PV installation rankings, Q1 2025

	Rank			Installations (MW_{dc})		
State	**2023**	**2024**	**Q1 2025**	**2023**	**2024**	**Q1 2025**
Kansas	46	47	28	26	19	32
Maryland	33	29	29	225	293	31
Rhode Island	24	40	30	322	135	25
North Carolina	11	31	31	909	196	24
Minnesota	29	21	32	241	545	22
Washington DC	45	44	33	37	36	16
Iowa	43	20	34	56	554	15
Washington	41	35	35	86	181	14
Utah	36	17	36	178	754	11
Montana	31	45	37	232	26	9
New Mexico	23	11	38	328	1,565	8
New Hampshire	42	42	39	58	39	8
South Carolina	32	39	40	228	151	6
Georgia	14	12	41	692	1,542	6
Delaware	47	46	42	21	21	3
West Virginia	50	38	43	10	167	3
Vermont	48	49	44	14	10	2
Wyoming	51	33	45	4	190	1.3
Nebraska	37	48	46	114	16	1.0
Mississippi	28	14	47	250	961	0.7
South Dakota	39	37	48	99	168	0.2
Alaska	49	51	49	12	2	0.2
North Dakota	52	52	50	0	0	0.05
Tennessee	34	50	51	210	3	0.02
Alabama	30	43	52	235	39	0

Source: Wood Mackenzie

2. Distributed solar-plus-storage

- **Solar-plus-storage accounted for 38% of residential solar installations in Q1 2025 (up from 32% in Q4 2024)**
- **Solar-plus-storage accounted for 6% of non-residential solar installations in Q1 2025, including commercial and community solar, (comparable to Q4 2024)**

A record high 38% of residential solar projects were paired with storage in Q1 2025

Residential solar-plus-storage installations grew by 10% quarter-over-quarter in Q1 2025 despite a 4% contraction in the residential solar market. Sustained customer demand for backup power amid grid outages, state-level incentives, and transitions to time-of-use rates or net billing structures fueled this growth.

California and Puerto Rico dominated the market, accounting for 54% and 29% of national installations, respectively. California's market, which had boomed since April 2023, showed signs of slowing down. The state's solar-plus-storage installations fell by 3% quarter-over-quarter in Q1, suggesting California has reached a demand equilibrium under the Net Billing Tariff. The need for resiliency drove Puerto Rico's strong market performance. The island set a quarterly record in Q1 with more than 13,600 projects deployed.

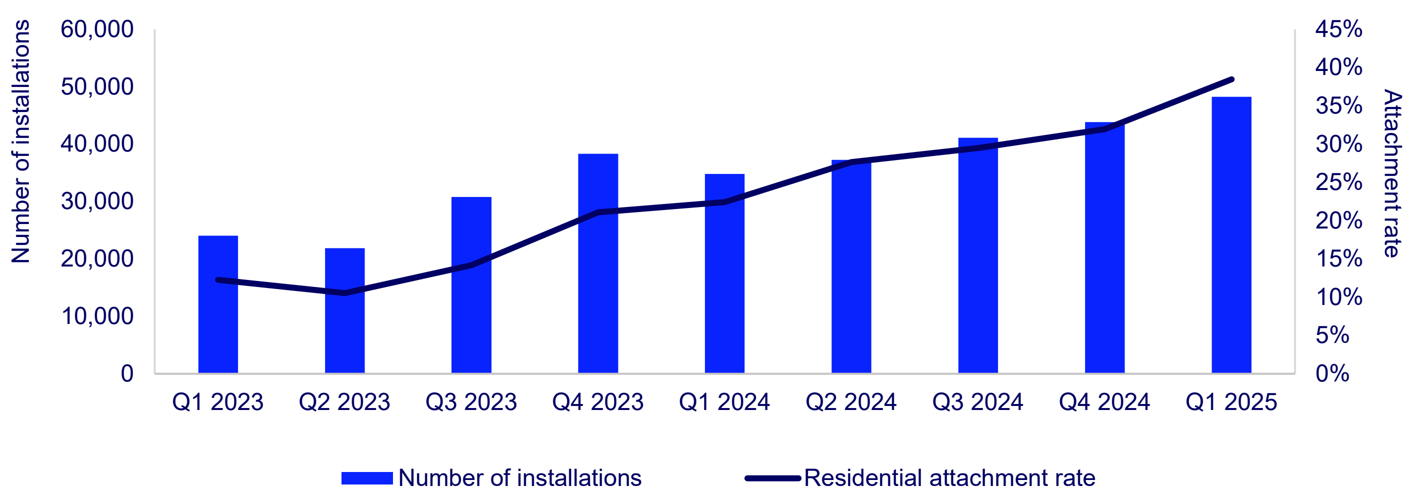
The national residential attachment rate, excluding Puerto Rico and California, grew to 10% in Q1 2024, up from 7% in Q4 2024. North Carolina, Illinois, and Texas led this growth. Duke's PowerPair incentive program in North Carolina increased storage adoption, with the state's attachment rate reaching 65% in Q1 2025, up from 13% in Q1 2024. In Illinois, some leading installers reported new sales with attachment rates above 80%, supported by the state's transition away from net metering and its smart inverter rebate. Demand for resilience and Virtual Power Plant (VPP) opportunities drove growth in Texas, with attachment rates rising from 11% in Q1 2024 to 26% in Q1 2025.

Tariffs and supply constraints pose headwinds for residential solar-plus-storage

Residential solar-plus-storage installers are preparing for battery price volatility due to tariffs imposed on China. After Liberation Day, residential battery prices increased by 10-15%. Despite recent adjustments in tariffs, both the duties themselves and the uncertainty surrounding implementation introduce risk to the market. Some installers and financiers with strong balance sheets have managed to secure a supply, but others have not been able to do so.

Supply constraints have also limited growth in the residential solar-plus-storage market. Installers have reported Powerwall shortages since Q3 2024. Tariff uncertainty may extend these constraints to other battery manufacturers, potentially dampening a pull-in of demand, caused by the possible elimination of the residential investment tax credit.

Residential attachment rate and solar-plus-storage deployments



Source: Wood Mackenzie

Non-residential attachment rate stays steady at 6%

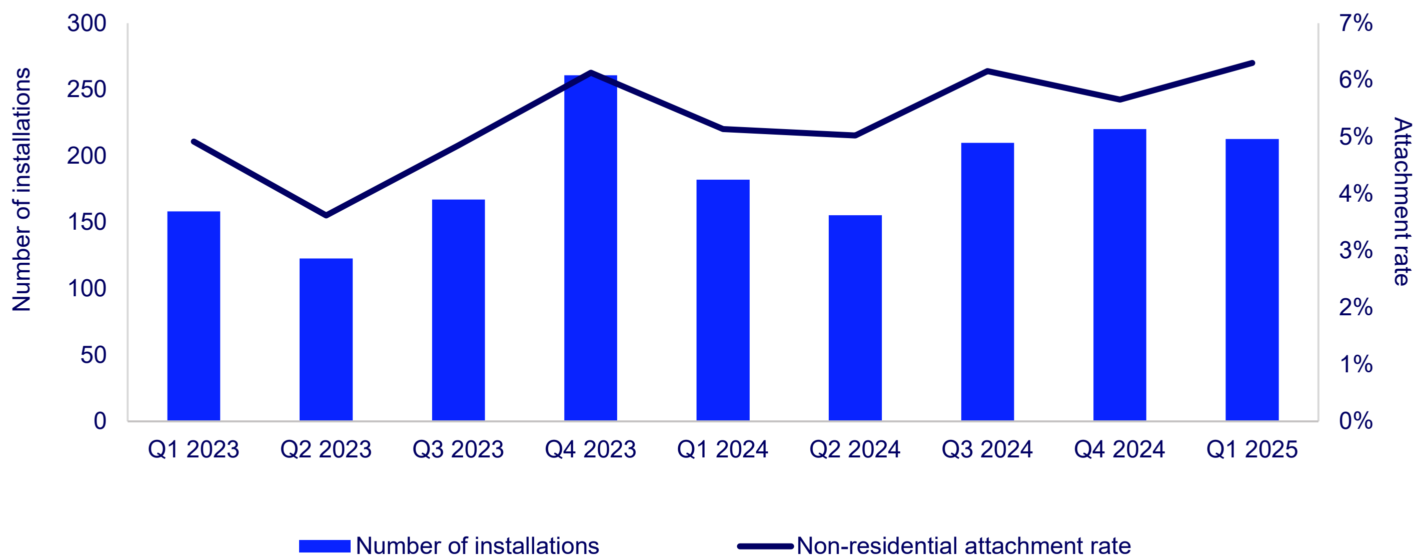
Non-residential solar-plus-storage deployments remained steady in Q1 2025, with approximately 213 installations, compared to 220 in Q4 2024. In Q1, California led with 15 MW_{dc} of commercial solar-plus-storage deployed, followed by Puerto Rico with 1.3 MW_{dc}, Arizona with 250 kW_{dc}, and Rhode Island with 200 kW_{dc}. Behind-the-meter commercial solar-plus-storage is driven by customer demand for resiliency, demand charge management, and demand response opportunities. Front-of-the-meter solar-plus-storage relies on incentives or policy drivers and is also supported by the economic benefits of oversizing solar systems while avoiding DC clipping.

Tariff impacts on non-residential solar-plus-storage remain uncertain

According to leading non-residential solar developers, storage additions to non-residential solar projects were already largely speculative or on the margin before tariffs. Tariffs will now compel companies to remodel projects. However, many installers have not yet delayed or abandoned their non-residential solar-plus-storage projects. This hesitation stems from the uncertainty surrounding future battery procurement. Costs remain difficult to predict 12 months in advance, making long-term planning challenging. Installers are waiting for more clarity before making significant changes to their project timelines.

Developers face challenges from tariff uncertainty when qualifying projects for programs with strict timelines. Massachusetts requires projects applying for the Distribution Circuit Multiplier as part of the Clean Peak Energy Portfolio Standard to come online in 2026 and 2027. Connecticut's Energy Storage Solutions program also enforces rigid interconnection deadlines. Installers risk losing incentives if tariffs hinder their ability to procure reasonably priced batteries in time for these deadlines.

Non-residential attachment rate and solar-plus-storage deployments



Source: Wood Mackenzie

3. Residential PV

3.1. Market overview and outlook

- **1,106 MW_{dc} in Q1 2025**
- **Down 13% from Q1 2024**
- **Down 4% from Q4 2024**

Residential solar capacity reached its lowest point in nearly four years last quarter

In Q1 2025, the residential solar market added 1,106 MW_{dc}, declining 13% year-over-year and 4% quarter-over-quarter. Compared to Q1 2024, 22 states experienced drops in installed capacity. California continued to lead the residential solar state capacity rankings with 255 MW_{dc} despite experiencing its lowest quarter since 2020. Puerto Rico and Florida followed, rounding out the top three markets.

Some installers in New England attribute the lower quarter to harsher winter conditions for installations compared to the previous year. However, continued market headwinds contributed to a weak quarter of installed capacity for states across the country. Nevada's quarterly installed capacity, for example, fell to its lowest point since 2020 in Q1 2025. The state has consistently ranked in the top 10 in recent years. However, rising solar penetration levels and recent regulatory changes have posed challenges on top of high interest rates and other headwinds. SB 293, which became effective in early 2024 (as detailed in *US Solar Market Insight 2023 year-in-review*) and changed the residential solar sales landscape in the state, has begun to significantly impact the market.

Capacity in Texas also fell to its lowest point since 2020. Many installers in Texas report that they have not experienced any sales recovery in the past few months. The residential solar financing mix in Texas has historically been mostly customer-owned, which may be a contributor to the state's struggles (the surge of third-party owned projects is driving growth in some states). While VPP opportunities are fueling growth for some installers, they have not been significant enough to stimulate statewide recovery.

Tax credit and tariff uncertainty are top of mind for the residential solar market

Challenging market conditions continue to plague the segment, with some installers describing this time as unprecedented turmoil. The residential solar market faces significant uncertainty in 2025, grappling with supply chain challenges due to tariffs, the potential elimination of tax credits, and continued high interest rates. These combined headwinds are a perfect storm and unchartered territory for the residential segment, resulting in a more challenging value proposition.

On top of low demand, some installers are confronting additional challenges in customer acquisition (besides the high cost). Even if customers initially commit, there is the risk that they will not move forward, with some installers reporting cancellation rates above 40%. Others are grappling with credit score restrictions, with some installers with a predominantly TPO financing mix experiencing more than one-third of their customers failing credit checks. As economic turmoil likely continues, these conditions may worsen.

Market headwinds dampen optimism for residential solar recovery, but long-term potential remains

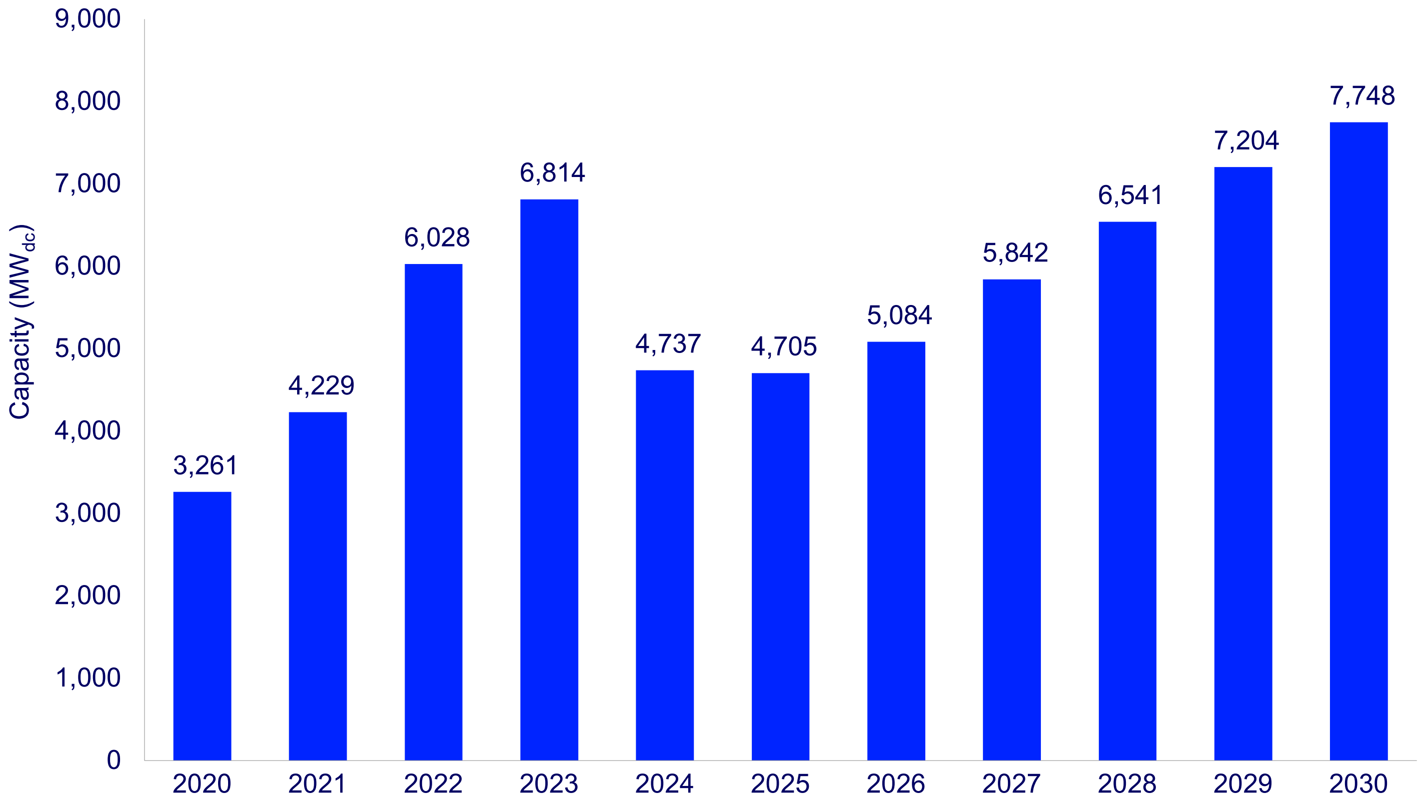
These challenges have dampened optimism for recovery in 2025. We downgraded our five-year residential solar outlook by 9% this quarter, expecting a slight contraction in installed capacity in 2025 compared with 2024. Recent tariff announcements introduce more economic uncertainty and risk, creating consumer hesitancy for large purchases. The additional tariffs resulted in an approximate 4% downgrade to our outlook compared to last quarter, and we further decreased our forecast due to continued low sales and installations and less recovery than expected, including in California.

Our Base case forecast does not incorporate the provisions proposed in the House reconciliation bill. While tariffs will impact demand in the near term (most significant impacts expected in 2026 and 2027), we still expect growth to return in 2026, driven by TPO momentum, eventual loan market recovery, and continued retail rate increases.

The House reconciliation bill's proposed provisions present a major downside risk, including the elimination of the tax credits under Section 25D for customer-owned solar and Section 48E for TPO leased systems. If this aspect of the bill moves forward, a market contraction would follow, resulting in a significantly smaller residential solar market than currently projected. The overall addressable market would shrink substantially; some installers report that it would be an adjustment to operate without the ITC, and some TPO providers do not expect to remain in business. Some financiers have already notified customers that new origination will halt soon for certain products to mitigate risk, even though the bill hasn't yet passed the Senate.

Despite near-term uncertainty and instability, the residential solar market still possesses significant long-term potential, as national market penetration remains under 10%. In our Base case forecast, we expect the segment to grow at an average annual rate of 9% between 2025 and 2030, adding more than 37 GW_{dc}, heavily driven by rising retail rates and resiliency concerns.

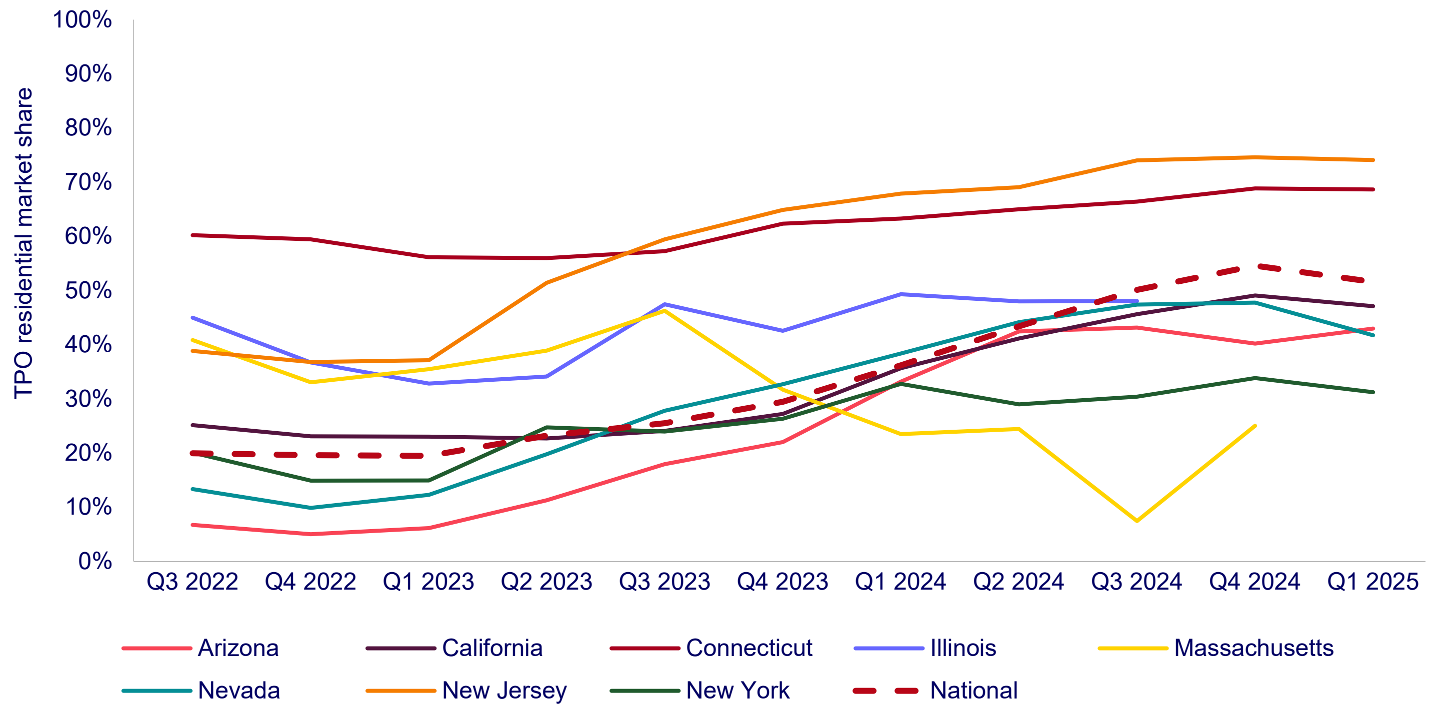
Residential solar installations and forecast, 2020-2030



Source: Wood Mackenzie

3.2. Trends in consumer finance

Percentage of new residential installations owned by a third party, Q3 2022 to Q1 2025



Source: Wood Mackenzie

State	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Arizona	7%	5%	6%	11%	18%	22%	33%	42%	43%	40%	43%
California	25%	23%	23%	23%	24%	27%	36%	41%	46%	49%	47%
Connecticut	60%	59%	56%	56%	57%	62%	63%	65%	66%	69%	69%
Illinois[1]	45%	37%	33%	34%	47%	43%	49%	48%	48%	--	--
Massachusetts[2]	41%	33%	35%	39%	46%	32%	23%	24%	7%	25%	--
Nevada	13%	10%	12%	20%	28%	33%	38%	44%	47%	48%	42%
New Jersey	39%	37%	37%	51%	59%	65%	68%	69%	74%	75%	74%
New York	20%	15%	15%	25%	24%	26%	33%	29%	30%	34%	31%
National	**20%**	**20%**	**19%**	**23%**	**26%**	**29%**	**36%**	**43%**	**50%**	**55%**	**52%**

TPO projects again made up more than half of the residential solar market in Q1 2025, reaching 52% share with more than 570 MW_{dc} of capacity installed. As loan interest rates remain high and consumer caution to make large purchases persists,

[1] Sufficient Illinois TPO data for Q4 2024 and onward was not available at the time of publication.
[2] The Massachusetts' TPO share is based on project-level data from the SMART program, which has had declining participation due to lower incentive rates, and therefore, isn't necessarily indicative of ownership trends in the state. Sufficient data was also not available for Q1 2025.

TPO products can be an attractive alternative option in some areas of the country. Many TPO providers report experiencing most of their growth in the tri-state area, where there are high retail rates, a trend reflected in the sustained high TPO market shares in Connecticut and New Jersey. However, some states' TPO shares have started to level off or slightly decline, as some installers report that the TPO portion of their financing mix remains high but has flattened out.

The future segmentation of the residential solar market is up in the air with the budget reconciliation bill. The ITC bonus adders are currently a major driver of residential solar TPO growth (customer-owned projects are not eligible). In our current Base case forecast, we expect the TPO segment to grow again in 2025 as the loan segment contracts for the third consecutive year, as lenders continue to experience declines in volumes. However, a lot may change over the next few months if the provisions in the current reconciliation bill become law.

3.3. State market overview

Top 10 residential solar state markets by Q1 2025 installations

Installations (MW_{dc})	Q2-2023	Q3-2023	Q4-2023	Q1-2024	Q2-2024	Q3-2024	Q4-2024	Q1-2025
California	579	743	480	355	293	313	278	255
Puerto Rico	58	98	95	55	74	74	94	94
Florida	183	123	138	127	103	103	69	87
Illinois	60	66	75	77	73	62	107	81
Texas	119	92	77	73	67	81	82	58
New Jersey	50	49	40	42	35	37	43	46
New York	67	55	54	47	45	43	49	45
Massachusetts	48	50	49	46	56	47	52	41
Arizona	89	87	77	64	53	44	49	40
Pennsylvania	42	40	39	30	29	39	42	35

Source: Wood Mackenzie

3.3.1. New York

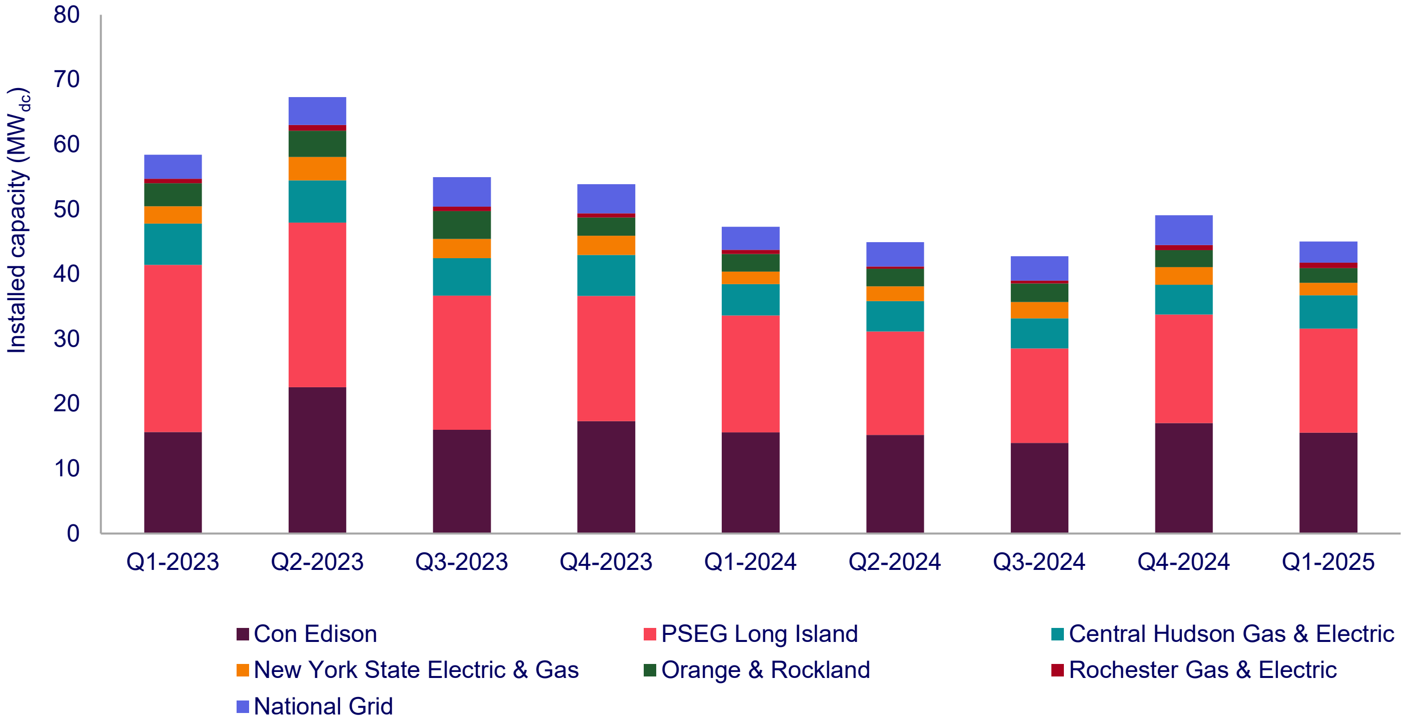
- **45 MW_{dc} installed in Q1 2025**
- **Down 5% from Q1 2024**
- **Down 8% from Q4 2024**

New York has been a consistent residential solar state market leader over the past decade

The New York residential solar state market has consistently ranked in the top 10 for installed capacity over the past decade, including in Q1 2025. Like states nationwide, New York has experienced lower installed capacity due to market headwinds like high interest rates.

Numerous factors support the stability of the New York residential solar market. PSEG Long Island and ConEdison comprise most of the state's capacity, each making up approximately one-third. ConEdison, in particular, has some of the highest electricity rates in the country. According to the EIA, ConEdison's average retail rate surpassed 30 cents per kWh in 2023, nearly double the national average. New York state averaged approximately 22 cents per kWh that year, the tenth highest state. These high (and rising) retail rates, coupled with the availability of retail rate net metering, stable state incentives, and a residential solar state tax credit, have fueled residential solar growth in New York.

New York residential solar installed capacity by utility, Q1 2023 - Q1 2025



Source: Wood Mackenzie

The NY-SUN incentive program comes to an end (ahead of schedule)

The NY-SUN program has been in place for more than a decade. The program was most recently expanded in 2022 to support 10 GW of installed capacity by 2030, with varying MW-block targets by region (ConEdison, PSEG Long Island, and the rest of the state). As a declining capacity block model, the incentives were designed to phase down over time. At the end of 2023, it became apparent that the program was ahead of schedule and under budget to achieve the 10 GW goal. One driver of these expected program savings was the increase and extension of the ITC under the IRA, which was not factored into the goal's roadmap.

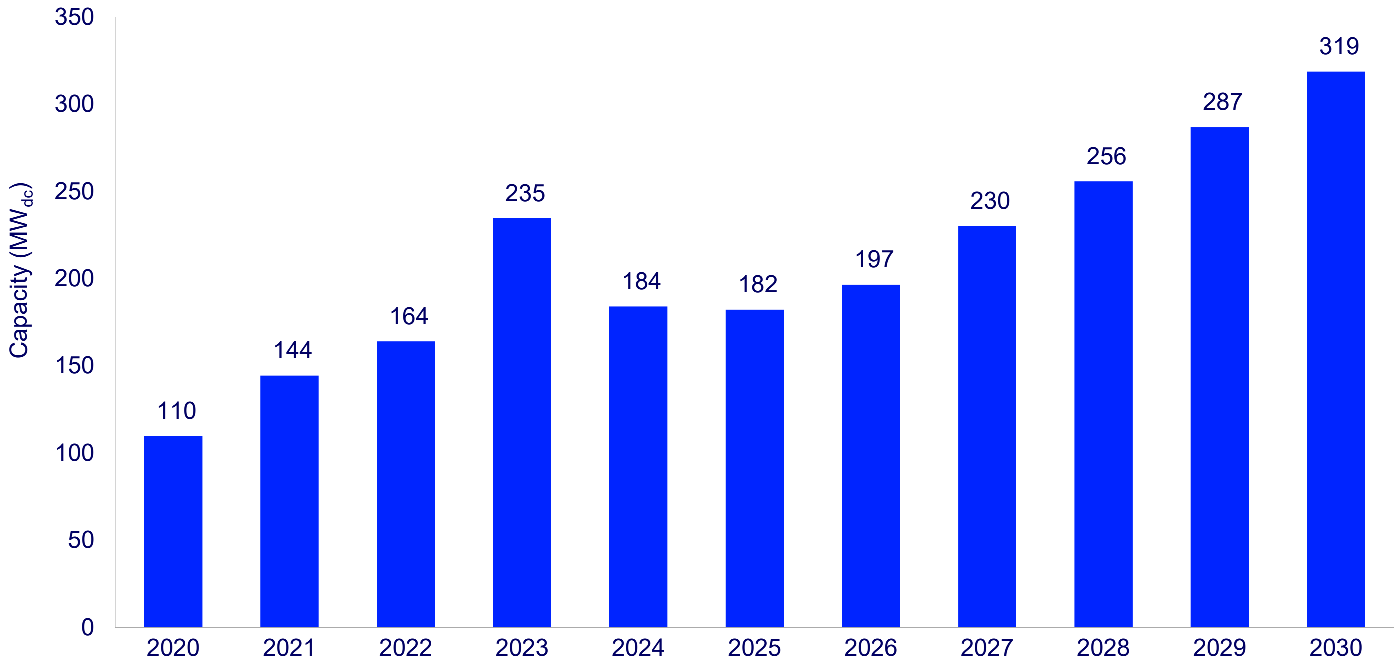
Ultimately, at the end of April 2025, the New York Public Service Commission (PSC) issued an order to reallocate the surplus NY-SUN funds. Out of the original budget of about $3.27 billion, there will be a $421 million surplus once installed capacity reaches the 2030 goal. Although some parties filed comments to raise the distributed solar goal to 20 GW by 2035, the PSC voted to allocate $150 million for Statewide Solar for All (low-income community solar program) and the remaining amount for future statewide clean energy fund programs.

Even without NY-SUN incentives, the New York residential solar consumer value proposition remains strong

While initial NY-SUN blocks provided residential customers with an incentive of approximately $1/W, incentive rates have fallen to $0.10/W (roughly $1,000 total for a project) in the most recent block and even down to zero for PSEG Long Island. While these reductions have made the NY-SUN program less salient in the state, proposed cuts to federal residential tax credits in conjunction with the loss of NY-SUN present risks to New York's residential solar growth.

Despite these headwinds, continued availability of net metering in the near term (with the eventual shift to the Value of Distributed Energy Resources rate structure) and rising retail rates support our expectation of 10% average annual residential solar growth in New York in our five-year outlook, assuming federal incentives remain in place.

New York residential solar installations and forecast, 2020-2030



Source: Wood Mackenzie

4. Commercial PV

4.1. Market overview and outlook

- **486 MW_{dc} installed in Q1 2025**
- **Up 4% from Q1 2024**
- **Down 28% from Q4 2024**

Note on market segmentation: Commercial solar encompasses distributed solar projects with commercial, industrial, agricultural, school, government or nonprofit offtakers, including remotely net-metered projects. This excludes community solar (covered in the following section).

The commercial solar sector achieved an all-time high for first-quarter installations but will decline in 2025

The commercial solar market reached its highest first quarter of installation capacity on record in Q1 2025. The segment added 486 MW_{dc}, a 4% year-over-year increase. Installations declined by 28% compared to last quarter, reflecting the typical difference between the year-end Q4 rush and regular Q1 new capacity. The surge in unprecedented Q1 growth was largely driven by the lasting wave of NEM 2.0 installations in California.

California's NEM 2.0 projects continue to come online in 2025, taking longer than initially anticipated. California installed 205 MW_{dc} in Q1 2025. We expect the state to maintain relatively high installation volumes at over 700 MW_{dc} this year. According to developers, every new Net Billing Tariff (NBT) agreement now includes a storage component, and securing deals increasingly requires working with more advanced, energy-conscious customers. We anticipate a slight contraction in capacity in 2025 and a major dip in 2026 as a result of this adjustment. Longer term, we expect an eventual recovery in California, driven by developers adapting to the NBT policy change, although the state's volume will not return to NEM 2.0 levels.

In congested state markets like New York and Illinois, developers are advancing their current project pipelines. However, maintaining the present rate of installation growth will not be feasible in the long term without significant interconnection enhancements. Various stakeholders in New York are joining forces and dedicating resources to develop extensive, forward-looking strategies for grid management to tackle these issues. New York installed 28.1 MW_{dc} of new commercial solar capacity in Q1 2025, a 51% decrease quarter-over-quarter and a 26% decrease annually. (Read an in-depth analysis of New York in Section 4.2.1.) In Illinois, state programs such as Illinois Shines and community adders incentivize commercial solar development, with 42.7 MW_{dc} installed in Q1 2025. Although Illinois remains a strong market, many of these projects are bigger community solar projects with one commercial & industrial (C&I) anchor tenant versus onsite traditional commercial solar projects.

Massachusetts is an example of a state that had a weaker Q1 2025, with only 2.9 MW_{dc} installed, a 66% year-over-year decline. Moreover, the pipeline of commercial solar projects in Solar Massachusetts Renewable Target (SMART) program continues to decline as this iteration of the program closes. Developers are awaiting the launch of the new SMART program to interconnect projects to the grid.

Program change is also plaguing projects over 1 MW in Maine after December's Net Energy Billing (NEB) deadline in December 2024. Developers report that Maine is in a downward spiral, with only 9.2 MW_{dc} installed in Q1 2025, a 92% quarter-over-quarter decline after the NEB deadline capacity pull-in. Given these challenges, we expect a 31% average annual contraction in Maine over the next five years.

Developers prioritize risk mitigation strategies in the face of federal policy uncertainties

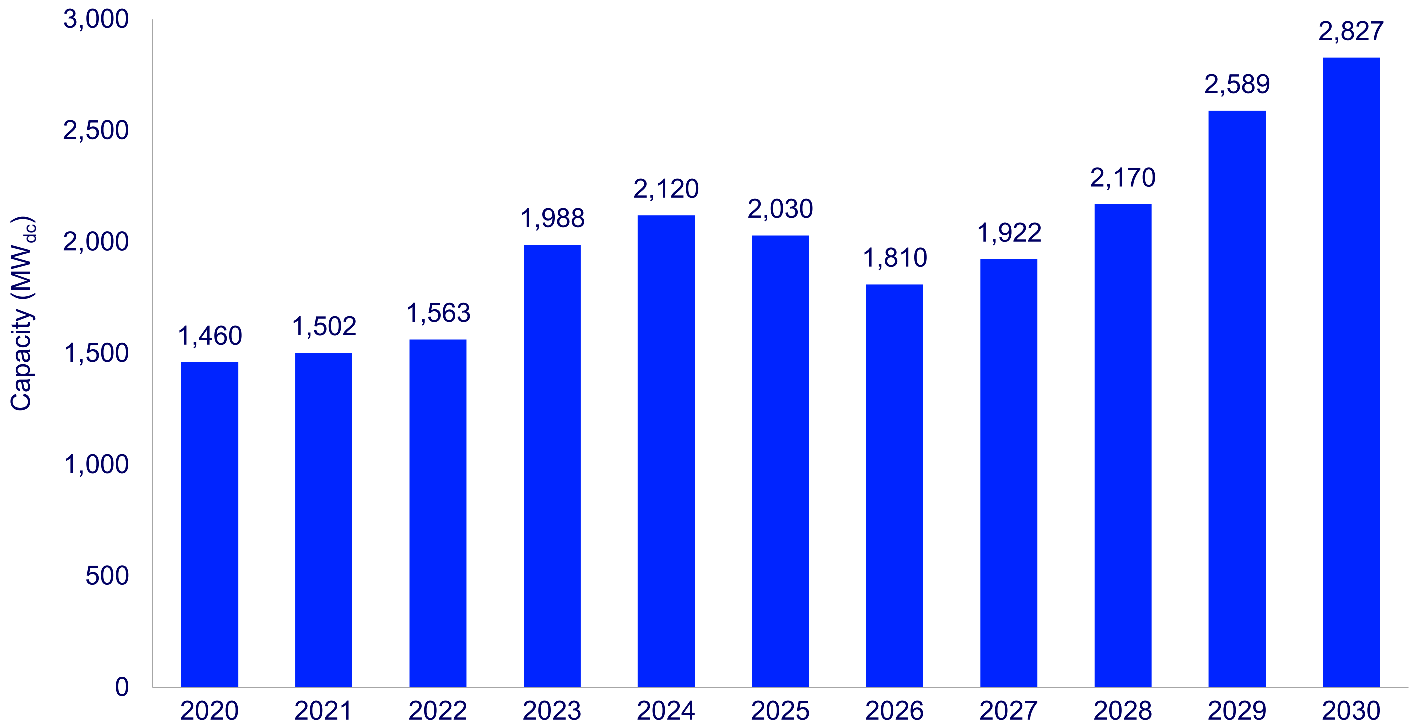
Amid federal policy uncertainty, developers are pushing forward with projects to maintain pipeline momentum and operational continuity. Nevertheless, the industry remains mindful of risks, such as the potential for early sunsetting of the Section 48E ITC or termination of transferability, along with macroeconomic forces. Developers are most concerned with derisking their projects and stabilizing their supply chain and internal procedures. Growing concerns within the industry about the potential discontinuation of the transferability market are beginning to impact deal flow and negotiations.

Smaller-scale commercial projects may face greater challenges in establishing safeguards. This is true even though transferability is considered a beneficial option rather than a crucial requirement, regardless of whether projects are evaluated individually or as part of a larger portfolio. We expect further development and guidance in the coming weeks.

We downgraded our five-year commercial solar forecast by 4% due to tariffs

Wood Mackenzie has adjusted its commercial solar forecast downward this quarter. Tariffs will affect commercial solar pricing, which resulted in a 4% downgrade to our five-year outlook. In 2025 and 2026, we expect a contraction of the national commercial solar market as California slows down. The segment will eventually recover and grow at an average annual rate of 12% from 2027 to 2030, driven by increasing electricity rates and ample land space in new states. Even though some saturated states are reaching their peak, emerging markets across the nation will continue to experience an increase in development activity. Overall, we expect the segment to grow at an average rate of 5% over the next five years.

Commercial solar installations and forecast, 2020-2030



Source: Wood Mackenzie

4.2. State market overview

Top 10 commercial solar state markets by Q1 2025 installations

Installations (MW_{dc})	Q2-2023	Q3-2023	Q4-2023	Q1-2024	Q2-2024	Q3-2024	Q4-2024	Q1-2025
California	90.3	140.6	302.1	153.0	173.9	212.1	202.6	205.5
Illinois	22.8	12.2	22.8	41.0	24.6	38.3	34.2	42.7
Pennsylvania	8.0	6.2	26.0	12.6	13.0	13.7	25.0	37.6
New York	17.7	10.8	22.6	38.3	18.8	48.5	57.9	28.1
Rhode Island	30.6	5.8	113.1	6.5	10.9	6.5	27.4	13.2
Arizona	28.7	6.3	8.4	13.4	5.7	9.5	8.6	13.1
Texas	11.3	13.5	19.9	11.2	7.7	18.2	17.8	12.5
Iowa	4.5	7.3	5.9	7.5	3.7	5.6	8.3	9.3
Maine	7.0	12.2	7.3	9.3	2.3	11.9	111.3	9.2
Minnesota	3.0	4.2	4.8	3.8	4.8	4.8	7.3	8.3

Source: Wood Mackenzie

4.2.1. New York

- **28 MW_{dc} installed in Q1 2025**
- **Down 26% from Q1 2024**
- **Down 51% from Q4 2024**

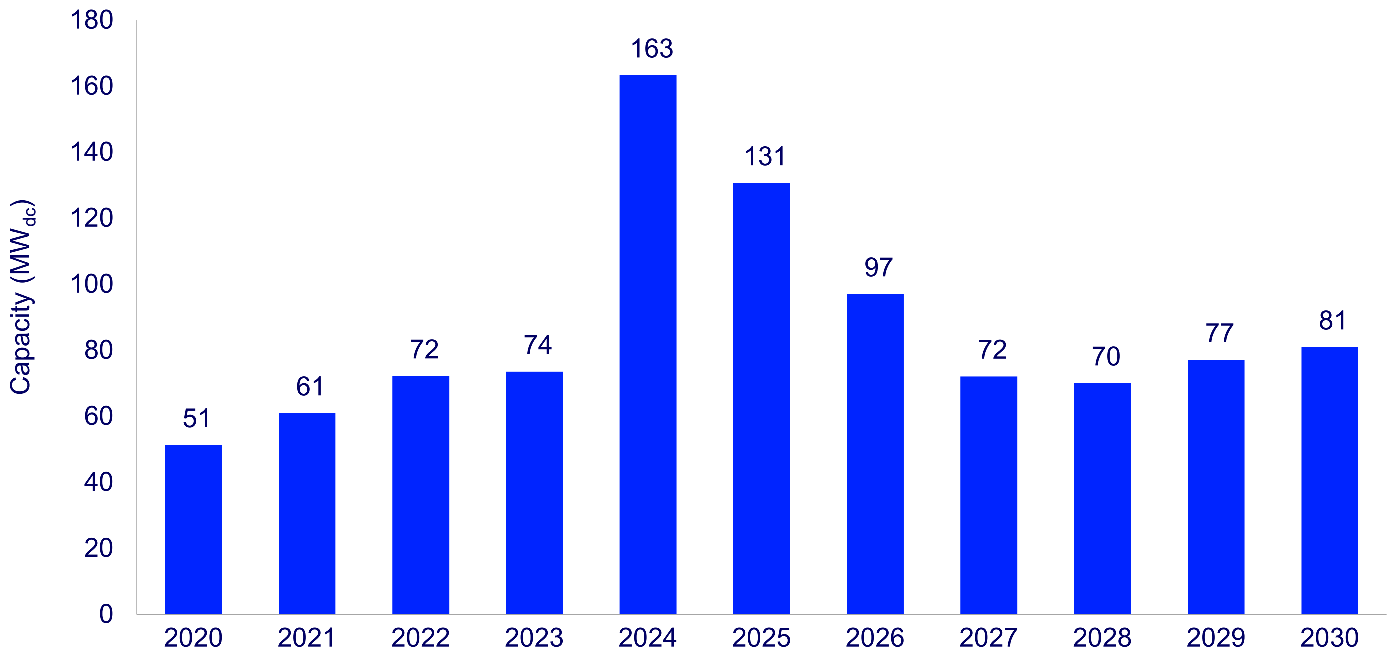
New York, a legacy commercial solar state, faces a market downturn due to increasing penetration and reduced incentives

New York has long been at the forefront of commercial solar implementation nationwide, maintaining its pioneer status until facing challenges this year. State incentives and high electricity prices have been the main drivers of commercial solar development success in New York. While electricity prices remain high, with an upward trend expected in the future, state incentives in New York are declining. On April 24, 2025, the New York PSC issued an order that removed $271M of previously authorized funding from NY-SUN. This NYSERDA program supports distributed solar projects across the state. As a result of declining incentives, New York's commercial solar pipeline has decreased 13% year-over-year.

Despite the obstacles, New York is still in the top five ranked states for new commercial solar capacity. Developers installed 28 MW_{dc} in the first quarter of 2025, with 140 MW_{dc} of new capacity installed in 2024. The Value of Distributed Energy Resources (VDER) in New York was established in 2017 by the PSC as part of the Reforming the Energy Vision (REV) strategy. It replaced the traditional net metering system with a more dynamic compensation mechanism for distributed energy resources such as solar and storage. Developers report that, while helpful for the future of the market, VDER calculations can be confusing; some components, such as the Demand Reduction Value, are based on outdated marginal cost-of-service studies and therefore don't reflect the true value. The VDER proceeding is currently addressing this challenge.

Regardless of the healthy volume of new capacity installed in 2024, commercial solar developers report that siting is increasingly difficult in New York's more saturated market, where viable sites near demand are depleted. With these challenges and financial incentives decreasing, we expect that the state's commercial solar market will decrease by 20% year-over-year in 2025, with a further decline in 2026 and 2027. We forecast mild growth in 2029 and 2030. Drivers are rising electricity prices, an expected increase in VDER revenue, and overall growth in demand in the state. From 2025 to 2030, New York is set to install almost 530 MW_{dc}.

New York commercial solar installations and forecast, 2020-2030



Source: Wood Mackenzie

4.2.2. Maryland

- **6.5 MW_{dc} installed in Q1 2025**
- **Up 67% from Q1 2024**
- **Down 34% from Q4 2024**

Commercial solar installations increase in Maryland, with SRECs improving project economics and payback periods

In Q1 2025, Maryland installed 6.5 MW_{dc} of commercial solar capacity, a 34% decrease quarter-over-quarter and a 67% increase year-over-year. However, volumes are generally trending upward, and we expect over 30 MW_{dc} to be installed within the state this year. Last year, 256 projects were installed in Maryland, compared to 157 projects in 2023, a 63% year-over-year increase.

In January 2025, the Brighter Tomorrow Act (SB-783) was enacted. It increased the value of Maryland Solar Renewable Energy Credits (SREC). Under SB-783, certified SRECs can now be used to satisfy 150% of compliance obligations, meaning compliance buyers will need to purchase 1.5 times the number of SRECs they would have previously. Additionally, the expiration period for SRECs has increased from three to five years. Higher-valued SRECs can help project economics and lessen payback periods, making it easier for developers to prove financial viability to clients.

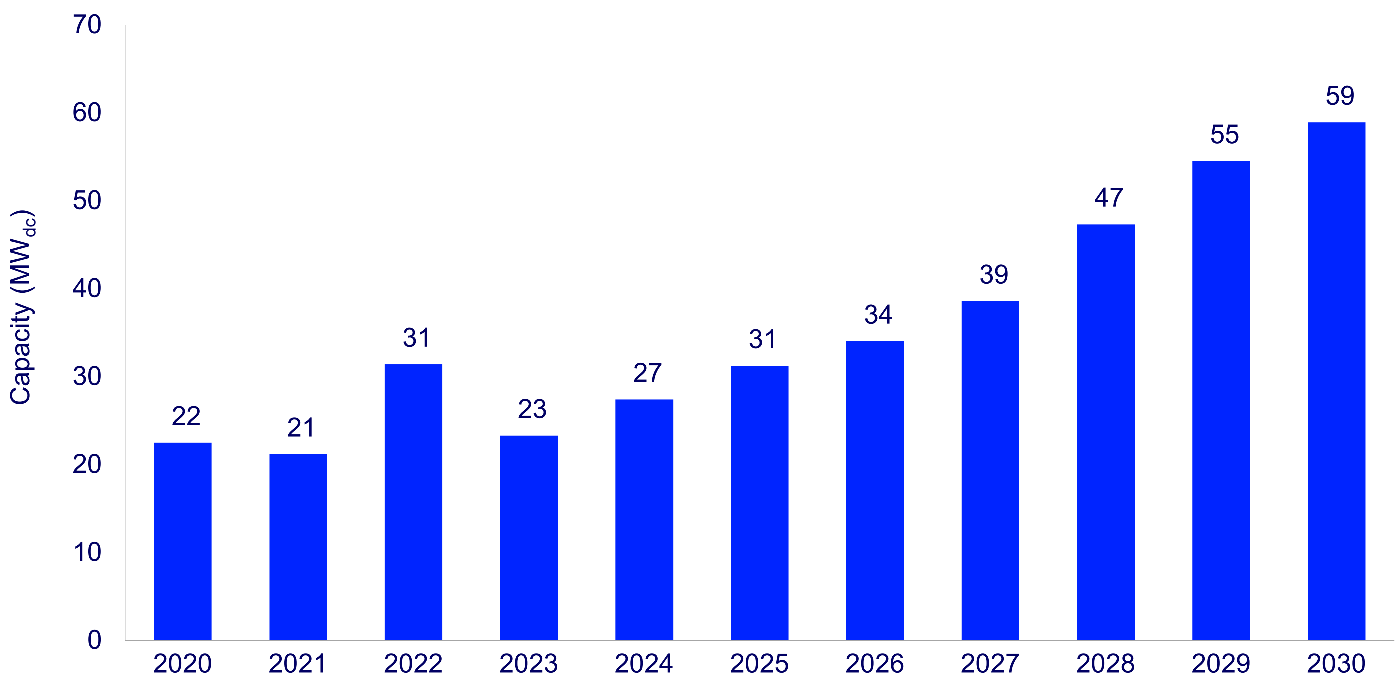
In addition to higher-valued SRECs, Maryland has a flexible solar state incentive program, the Maryland Solar Access Program (MSAP). Although MSAP primarily focuses on residential solar installations, it also benefits the commercial sector. Commercial and industrial entities can leverage the program in several ways: utilizing commercial solar options within the program, hosting community solar projects on their properties to potentially create new revenue streams, applying MSAP grant funds towards new solar PV system installations, and acting as third-party applicants for eligible residents. This last option enables C&I entities to receive grants and install solar PV systems on residential properties, allowing C&I entities to participate in and benefit from the MSAP despite its primary residential focus.

Furthermore, Maryland's net metering cap increased from 2 MW to 5 MW in 2023, allowing developers to take advantage of economies of scale. This change unlocked newer opportunities and bigger project sizes in Maryland. Many developers report having large pipelines in Maryland as well as acquisition and community solar opportunities.

Maryland's installations continue to gradually increase as developers look to mid-size markets

Developers are increasingly excited about commercial solar development in newer and emerging markets such as Maryland. Available labor and increasing energy rates are attracting developers to emerging markets, leading to a thriving commercial solar sector, as in many developing markets. This growth is propelled by two key factors: comparatively low development expenses relative to other regions in the country and an abundance of suitable locations for solar installations. We expect strong growth in Maryland over the course of our commercial solar outlook. As mid-size and non-legacy commercial solar states continue to draw developers, we expect Maryland to experience consistent growth and install more than 230 MW_{dc} from 2026 to 2030.

Maryland commercial solar installations and forecast, 2020-2030



Source: Wood Mackenzie

5. Community solar PV

5.1. Market overview and outlook

- **244 MW_{dc} installed in Q1 2025**
- **Down 22% from Q1 2024**
- **Down 71% from Q4 2024**

Note on market segmentation: Community solar projects are part of formal programs in which multiple residential and non-residential customers can subscribe to the power produced by a local solar project and receive credits on their utility bills.

The national community solar market will contract by 22% in 2025 due to lower expected volumes in New York

Community solar installations declined 22% year-over-year in Q1 2025, resulting in 244 MW_{dc} of new capacity. Five out of 15 state markets experienced quarterly declines compared to Q1 2024. Massachusetts and New Jersey saw particularly sharp drops, with installed capacity falling by 78% and 98% year-over-year, respectively. In Maine, capacity plummeted 85% year-over-year, confirming the expected drop-off following the Net Energy Billing incentive deadline in December 2024. New volumes in New York also declined slightly, yet the state continues to command 52% of the total market.

We expect the national community solar market to contract by 22% this year, following a particularly strong 2024 for the segment. However, installed capacity in 2025 will still exceed 2023 volumes, reaching approximately 1.5 GW_{dc}. New York and Illinois will drive most of this year's capacity, comprising 59% of expected volumes. However, new capacity in New York will fall by 31% in 2025 due to increased saturation and longer development timelines, contributing significantly to the national contraction. On the other hand, Illinois will grow approximately 30%, further solidifying its position as a top market for long-term success. Additionally, momentum will continue building under the new successor programs in New Jersey and Maryland.

The amount of community solar capacity under development greatly exceeds our near-term forecast

Community solar capacity under development and construction significantly exceeds our near-term outlook. Developer surveys and project-level data reveal a national pipeline of around 7.5 GW_{dc} in the 15 state markets Wood Mackenzie currently forecast. New York and Illinois alone have a community solar pipeline totaling nearly 5 GW_{dc} as of Q1 2025. However, due to lengthy interconnection studies and grid upgrades, we expect only a fraction of that capacity to come online each year. The pipeline is more than double the 3 GW_{dc} expected to come online by the end of 2026. In addition to grid upgrades, the cyclical nature of community solar incentive programs poses a key obstacle to efficient interconnection. Program administrators process hundreds of new applications simultaneously when new capacity blocks are released, inevitably leading to delays. This is consistently true in states with newer programs, such as Delaware, Virginia, and New Mexico.

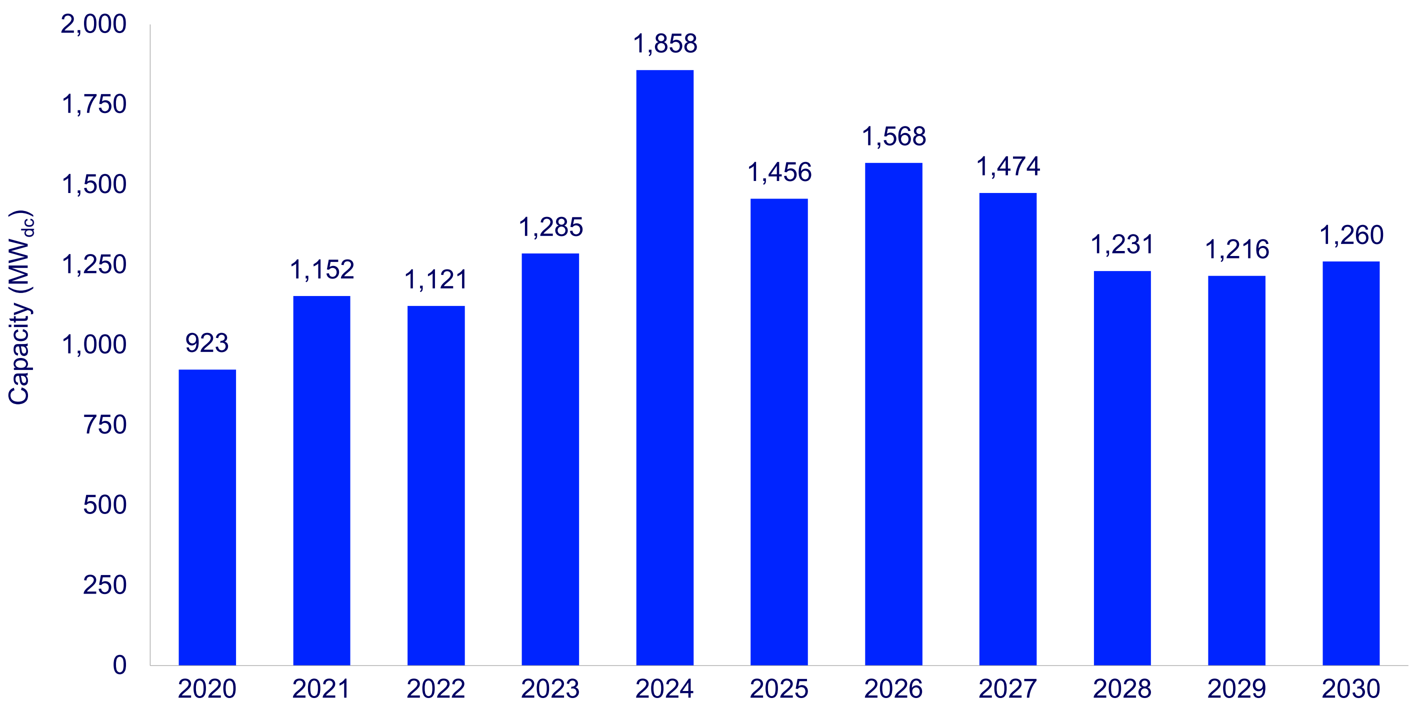
Despite longer project timelines, pipelines in key community solar state markets remain healthy, supporting the market's health through our five-year outlook. Stakeholders continue to advocate for interconnection reform to help alleviate backlogs in the current pipeline. Developers take particular interest in reforms that include cost-sharing for grid upgrades and pathways for flexible interconnection. The large project pipeline also provides some cushion for the segment should there be detrimental changes at a federal level, such as the removal of the ITC. If utilities improve the pace of interconnection, we expect a greater portion of the pipeline to reach completion before potential changes take effect.

Without additional statewide programs, community solar growth will stagnate through 2030

Overall, we expect the national market to contract by an average of 6% annually through 2030. Significantly, our five-year outlook includes only states with active programs and does not include those with proposed program legislation, leaving room for upside potential if new legislation passes this year or in the future. Several states have progressed toward enacting community solar programs this year. In May, the Pennsylvania House passed HB 504, and California policymakers re-introduced legislation to create a scalable, statewide program. Community solar is also garnering bipartisan support. A Montana community solar bill passed out of both Republican-controlled chambers in April. Additionally, Republican lawmakers in Georgia, Iowa, Missouri, and Ohio have sponsored bills to spur community solar development in their states. The pre-development pipeline in potential markets, which includes site acquisitions, exceeds 1.5 GW_{dc}. If legislators enact new programs this year, we expect to see an upside to our base case forecast as soon as 2028.

We continue to monitor federal policy changes and implications for the community solar segment. New tariffs on solar components led to a 4% decrease in our five-year outlook compared to last quarter. The latest draft of the budget reconciliation bill would hinder market growth. Removing or phasing out federal incentives, including the ITC, would significantly increase payback periods and limit financing availability. As the reconciliation process unfolds over the coming months, we will incorporate its impacts into our Base case forecast accordingly.

Community solar installations and forecast, 2020-2030



Source: Wood Mackenzie

5.2. State market overview

Top 10 community solar state markets by Q1 2025 installations

Installations (MW_{dc})	Q2-2023	Q3-2023	Q4-2023	Q1-2024	Q2-2024	Q3-2024	Q4-2024	Q1-2025
New York	111.8	93.4	201.2	138.8	168.2	128.9	390.2	127.0
Illinois	27.3	17.8	50.0	38.4	65.1	54.3	61.5	62.5
Colorado	0.6	-	20.0	8.5	6.6	8.0	25.1	11.5
Maine	60.5	75.1	86.6	66.1	33.1	80.4	209.3	9.8
Rhode Island	3.1	-	0.9	-	-	-	9.5	6.5
Minnesota	13.7	6.9	19.7	3.8	5.7	11.6	13.5	5.7
Oregon	0.5	0.7	-	-	8.0	7.3	4.3	4.4
California	3.9	3.8	-	3.9	13.0	-	45.2	3.9
Maryland	27.7	26.5	7.4	3.3	26.8	11.6	25.0	3.5
Washington DC	1.2	2.6	1.6	0.7	6.8	3.2	1.6	3.5

Source: Wood Mackenzie

5.2.1. Minnesota

- **5.7 MW_{dc} installed in Q1 2025**
- **Up 51% from Q1 2024**
- **Down 58% from Q4 2024**

Minnesota's revamped community solar program aims to revitalize the market, but challenges persist

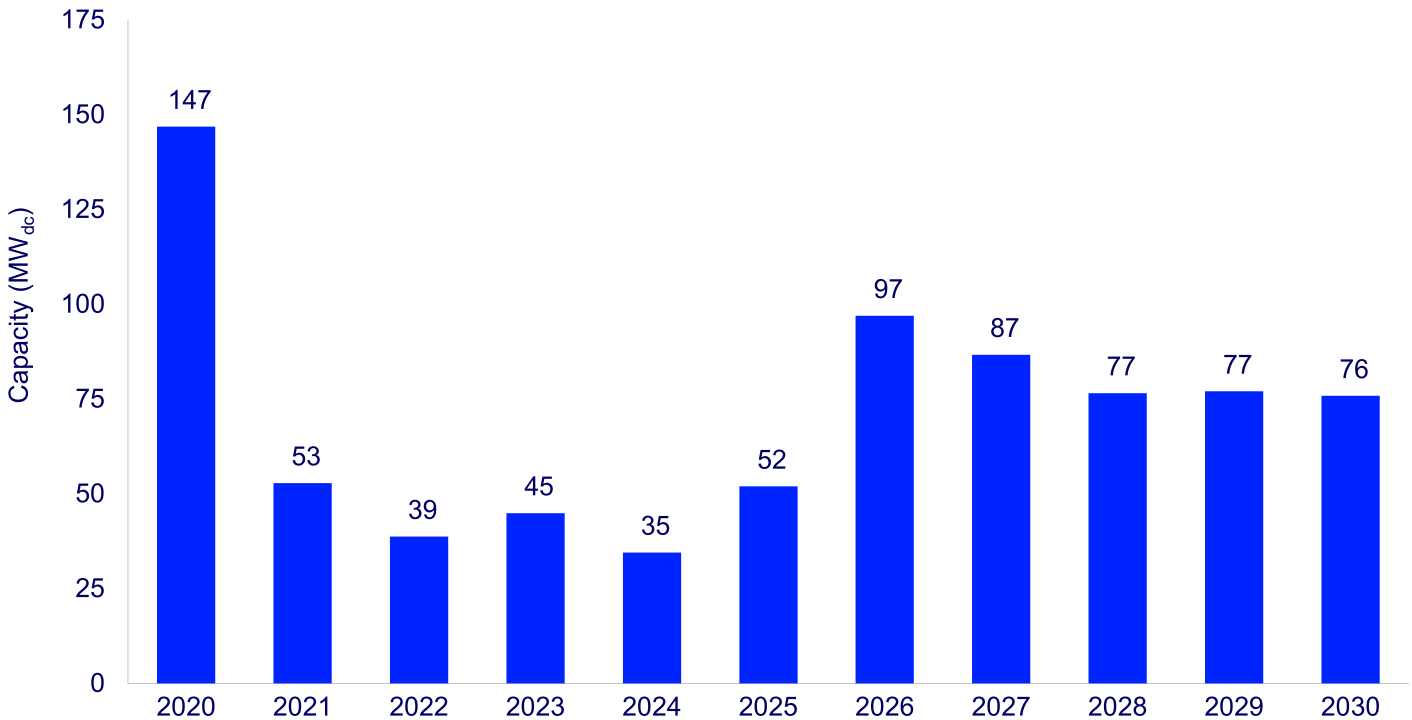
Minnesota installed 5.7 MW_{dc} of community solar capacity in Q1 2025, a 51% increase year-over-year. The Minnesota Community Garden program, one of the earliest community solar programs in the country, propelled the state's standing as a dominant market through 2020. Growth plummeted after 2020 due to the burdensome siting restrictions, lower incentive values, and interconnection delays. However, in May 2023, the Minnesota Governor signed HF 2310 into law, revamping the program and breathing new life into the market. The new LMI-Accessible CSG program launched in February 2024 with an initial 100 MW offering. The Department of Commerce made an additional 100 MW_{dc} available in February 2025. Capacity blocks will phase down to 80 MW per year beginning in 2027 and 60 MW per year in 2031 and beyond, enabling at least 680 MW through 2030.

The revamped program initially attracted fresh interest and excitement from developers. The new rules allow developers to build community solar anywhere in the state and extend the project size cap to 5 MW. The legislation also required Xcel to implement consolidated billing, streamlining subscriber acquisition and management. Additionally, the program reserves 55% of capacity for "public-interest" subscribers, including low-to-moderate income subscribers and public entities such as schools, religious institutions, and non-profits. Developers receive a more favorable credit rate for these subscribers than the legacy program. However, interconnection obstacles and utility opposition dampened initial excitement, proving persistently challenging in the state. Installed capacity totaled 25 MW_{dc} in 2024, an all-time annual low for Minnesota. We expect interconnection constraints to ease slightly as new capacity under the revamped program continues to come online. The near-term development pipeline sits at 116 MW_{dc}. We expect this pipeline to be fully built out by 2026, with more capacity from subsequent annual blocks totaling 368 MW_{dc} through 2030.

Proposed legislation to sunset the state's community solar program by 2028 threatens new capacity

State lawmakers are threatening to repeal Minnesota's community solar program despite the market's potential for new growth. SF 2393, the "Energy Omnibus Bill", proposes sweeping rollbacks to renewable energy incentives in the state, including the repeal of the new LMI-Accessible CSG program. This bill, if passed, will effectively sunset the program by July 2028, removing over 300 MW of potential capacity. Proponents argue that the once-successful program has become too costly for utilities and non-subscribing customers. Our base case forecast currently remains unchanged; however, we continue to monitor downside implications if this legislation passes.

Minnesota community solar installations and forecast, 2020-2030



Source: Wood Mackenzie

6. Utility PV

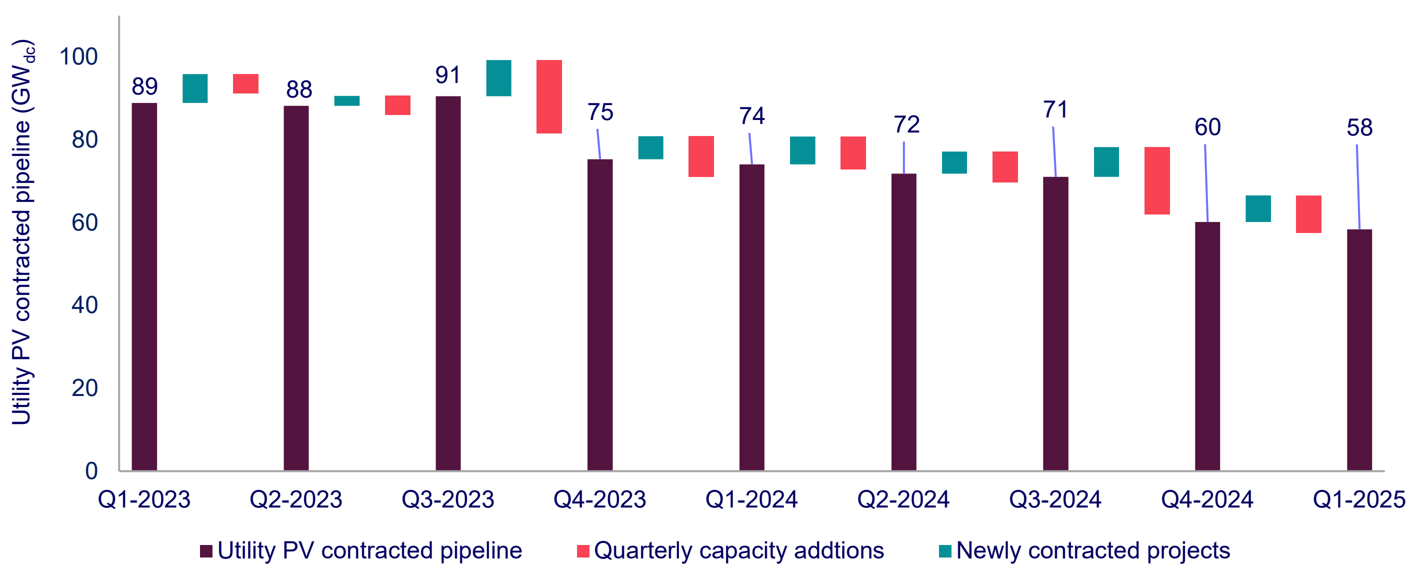
6.1. Market overview and outlook

- **9.0 GW_{dc} installed in Q1 2025**
- **Down 7% from Q1 2024**
- **199 GW_{dc} of utility-scale solar will be added between 2025 and 2030**

Utility-scale solar momentum continues in Q1 2025, but policy uncertainty drives a pipeline contraction

The utility-scale sector installed 9.0 GW_{dc} of projects in Q1 2025, representing a 7% decline year-over-year. The top five states with the largest installations include Texas, Florida, Ohio, Indiana, and California, making up over 65% of total installations this quarter. Contracted projects reached 5.7 GW_{dc} in Q1 2025, a 2% increase year-over-year. Large technology corporate buyers including Meta, Amazon, and Verizon secured 55% of the contracted projects in Q1 2025 to support their growing energy needs and clean energy goals. The bulk of projects with corporate off-takers were in Texas, with the highest activity coming from Meta's PPA contracts.

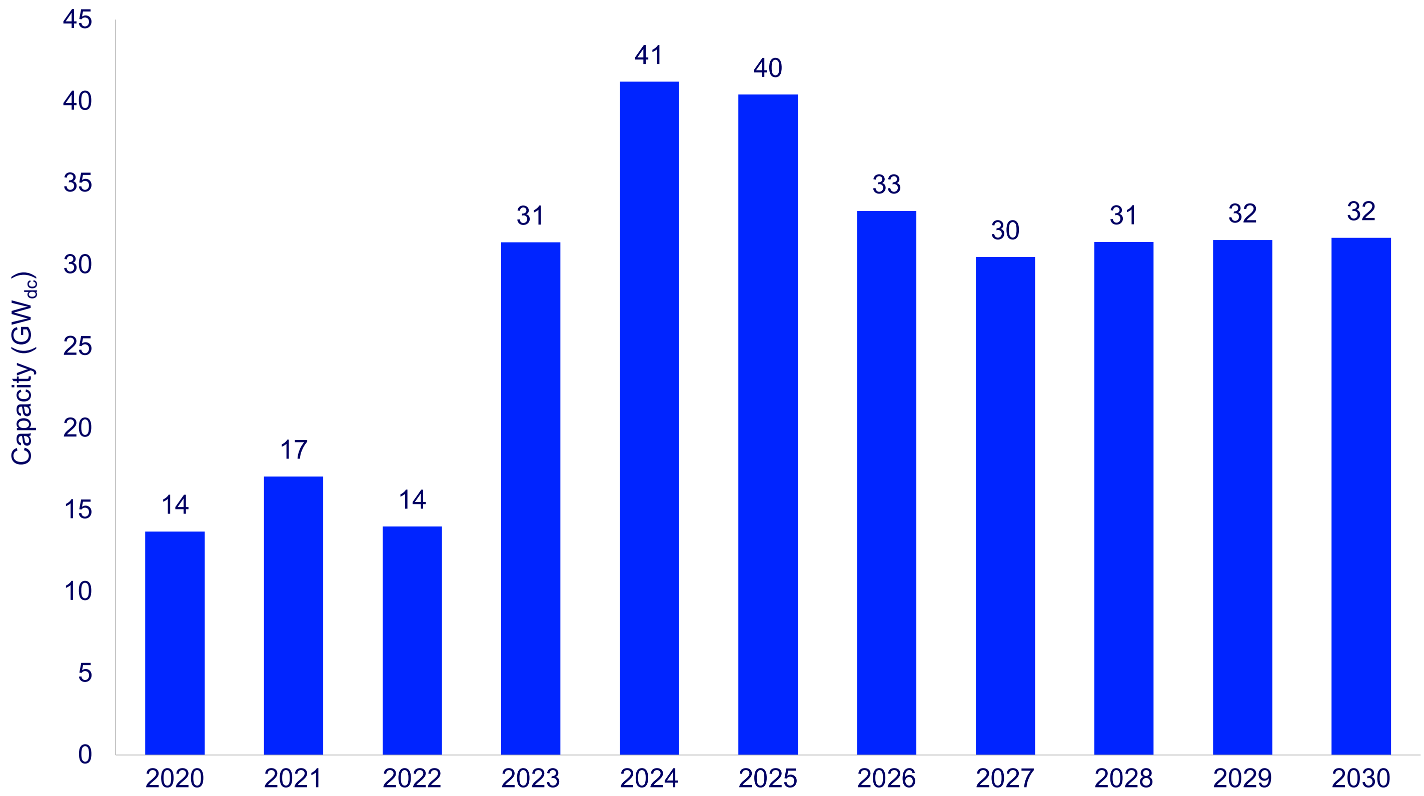
Utility-scale contracted pipeline, Q1 2023 to Q1 2025



Wood Mackenzie projects that 199 GW_{dc} of new utility-scale solar capacity will be installed from 2025 to 2030. Installation momentum from 2024 will continue into 2025, but installed capacity will start to decline and plateau starting in 2026 from a contraction in the overall pipeline. This decrease is primarily driven by general policy and tariff uncertainty, particularly potential changes in federal tax incentives and ongoing trade disputes affecting solar panel imports, creating hesitancy for newly contracted and early-stage projects.

Further challenges arise from PJM's gas-focused initiative and market caps, as well as proposed legislation in Texas, though that legislation failed recently. Both pose potential obstacles for utility-scale solar projects and could significantly impact renewable energy development in these regions. However, the forecast also has potential upsides. Increasing energy demand from AI and data centers, along with supply chain issues for large gas turbines, position utility-scale solar, paired with storage as a (maybe the only) viable solution to meet expected growth.

Utility-scale installations and forecast, 2020-2030



Source: Wood Mackenzie

6.2. Upsides and risks to the forecast

6.2.1 Forecast tailwinds

Proposed bill HR 2301 could reshape solar development on public lands

Rep. Mike Levin (D-CA) has reintroduced HR 2301, a bill aimed at accelerating renewable energy development on public lands while preserving conservation efforts. The legislation proposes to establish priority areas for renewable projects and increase the national goal for clean energy production on public lands from 25 GW_{ac} to 60 GW_{ac} by 2030. Notably, the Bureau of Land Management (BLM) has already exceeded its initial 25 GW_{ac} target, after approving 36 GW_{ac} by year-end 2024, including nine utility-scale solar projects totaling 6 GW_{ac}. HR 2301 aims to build on this momentum while balancing environmental concerns. It proposes allocating 40% of project revenue to a new conservation fund and streamlining the permitting process for clean energy projects, with safeguards for wildlife and cultural resources. Backed by various environmental and energy organizations, the bill has been referred to the Committee on Natural Resources and the Committee on Agriculture for review. If passed, it could continue to increase utility-scale renewables development on federal lands.

PJM and Google AI partner to tackle interconnection queue processes

PJM Interconnection's partnership with Google's artificial intelligence platform, Tapestry, aims to streamline grid interconnection processes, potentially reducing wait times for utility-scale solar projects. This initiative aims to integrate PJM's numerous databases and tools into a unified model, potentially streamlining access to critical information for project developers, grid planners, and operators. The process is expected to roll out this year and be phased in over several years to address PJM's interconnection backlogs.

If successful, this AI-driven approach could accelerate project timelines, reduce costs, and increase the overall efficiency of solar project development in the PJM region, as solar projects comprise 47% of all active projects in PJM's interconnection queue. Moreover, it could set a precedent for other grid operators to adopt similar technologies, potentially revolutionizing interconnection processes nationwide. The initiative has garnered praise from industry groups. It also aligns with recent FERC recommendations for leveraging automation to expedite interconnection processes, signaling a broader shift towards technological solutions to grid integration challenges for renewable energy projects.

Proposed Texas legislation posing challenges for new solar development defeated

The Texas Legislature considered three key bills, now defeated, that could have significantly impacted renewable energy development in the state. These bills would have had a chilling effect on the market, particularly for solar projects. SB 388 proposed a dispatchable generation credits trading program aimed at ensuring that 50% of new generating capacity in ERCOT comes from dispatchable sources after January 1, 2026. This bill excluded solar and hybrid projects from the dispatchable category. As a result, it may have indirectly disadvantaged solar development by creating incentives for competing dispatchable energy sources.

Additionally, SB 819 introduced a new siting regime for solar and wind projects exceeding 10 MW_{ac}. This legislation would have required developers to navigate a multi-layered permitting process, including local approval, public hearings, and detailed environmental and decommissioning plans. These new requirements were likely to extend timelines, increase costs, and add complexity to solar development in Texas, potentially deterring some projects or causing significant delays in their completion.

Finally, SB 715 focused on adjusting the implementation of generation reliability requirements. This bill would have granted the Texas Public Utility Commission discretion to phase in these standards earlier than initially planned. For solar developers, this could have meant facing additional hurdles to meet evolving reliability criteria, potentially complicating project planning and execution.

6.2.2 Forecast headwinds

PJM's gas-focused initiative and market caps create potential hurdles for renewable projects

PJM's Resource Reliability Initiative is a one-time process that expedites projects through its interconnection queue. While aimed at enhancing reliability, this initiative may hinder the progress and competitiveness of utility-scale solar projects in the queue. PJM has selected 51 projects totaling 11.8 GW_{ac} for this expedited review. The selected projects heavily favor gas-fired generation at 69%, followed by battery storage at 19%, nuclear at 12%, and coal, with a 0.1% contribution. This composition, with 39 uprates to existing plants and 12 new facilities, signals a significant shift in preference towards gas in PJM's near-term resource mix. However, the grid impact in the short-term will be limited, as 29 of the selected RRI projects are going to enter commercial operation after 2027. The prioritization of gas in this fast-track process could create additional barriers for solar projects already waiting in the interconnection queue, by potentially increasing network upgrade costs and impacting developers' project timelines and financial planning.

Furthermore, the increased gas capacity, combined with FERC's recent approval of PJM's proposal to add a floor and ceiling cap for the next two delivery cycles, might influence future capacity market prices. PJM's price collar could stabilize revenues for solar projects in the short-term but may dampen long-term investment incentives if the caps artificially suppress prices. At the same time, the compressed auction schedule could hinder solar development by reducing the time available for project planning and construction between auctions and delivery years.

Proposed reconciliation bill could reshape the utility-scale solar landscape

The draft reconciliation bill proposes significant changes to clean energy tax credits. These changes could spur a rush to complete solar projects before credit reduction, followed by a potential slowdown in development. Additionally, proposed restrictions on credit transferability and unadministrable foreign entity involvement may make the tax credits effectively worthless for projects beginning construction 60 days after enactment.

The proposed bill could significantly reshape the US solar industry, but unlike past construction rushes before an expected phaseout of the tax credits in 2022, the sudden and dramatic changes could halt many projects that are even close to construction. This shift could drive an increased focus on cost reduction and technological innovations to maintain competitiveness. Additionally, without an effective way to access the tax credits, including the domestic content bonus, developers may have to look for ways to mitigate PPA price impacts, likely straining domestic procurement plans.

However, the current landscape presents unique challenges. Policy uncertainties and tariff issues are already complicating developers' efforts to secure contracts, financing, and equipment. It remains unclear whether the rush to capitalize on incentives will outweigh the hesitation caused by market uncertainties. Significantly, the Senate could still substantially modify the bill, potentially altering its impact on the solar sector. This legislative uncertainty adds another layer of complexity to an already dynamic situation.

6.3. Financing and procurement trends

The changing political landscape creates a challenging environment for project financing

The recently passed House bill introduces dramatic and rapid changes to renewable energy tax incentives, including an accelerated phaseout of the ITC and PTC. As of this report's publication, the proposed law also mandates project construction to begin within 60 days of the bill's enactment to safe harbor projects under the existing tax code. It requires their completion by 2028 to be eligible for the credits. Additionally, the bill proposes to eliminate the options for transferability along with the phaseout of the credits.

The new constraints create a particularly challenging environment for project financing. The compressed project timelines intensify competition for equipment, skilled labor, and grid interconnection capacity, while the potential repeal of transferability could restrict financing options, especially for smaller projects. Additionally, the current economic climate, which is characterized by rising bond yields and increased capital costs, could further complicate project viability.

The bill also adds project ownership and component sourcing restrictions that echo the unworkability of the original domestic content bonus guidance. They would require the taxpayer (project owner) to demonstrate an untenable level of supply chain visibility. And, critically, given the compressed timelines, there may be little time between getting guidance on implementing the complex statute, which has notably vague language, and the placed-in-service deadline. This may allow limited time to finance projects not already well underway.

It is important to note that while these strategies can help developers navigate the current uncertainty, the legislative process for this new bill is still not complete. The Senate could still modify the bill substantially, potentially altering or even removing some of the proposed changes. This ongoing uncertainty underscores the need for developers to remain flexible and prepared for various scenarios as they plan their project pipelines and financing strategies.

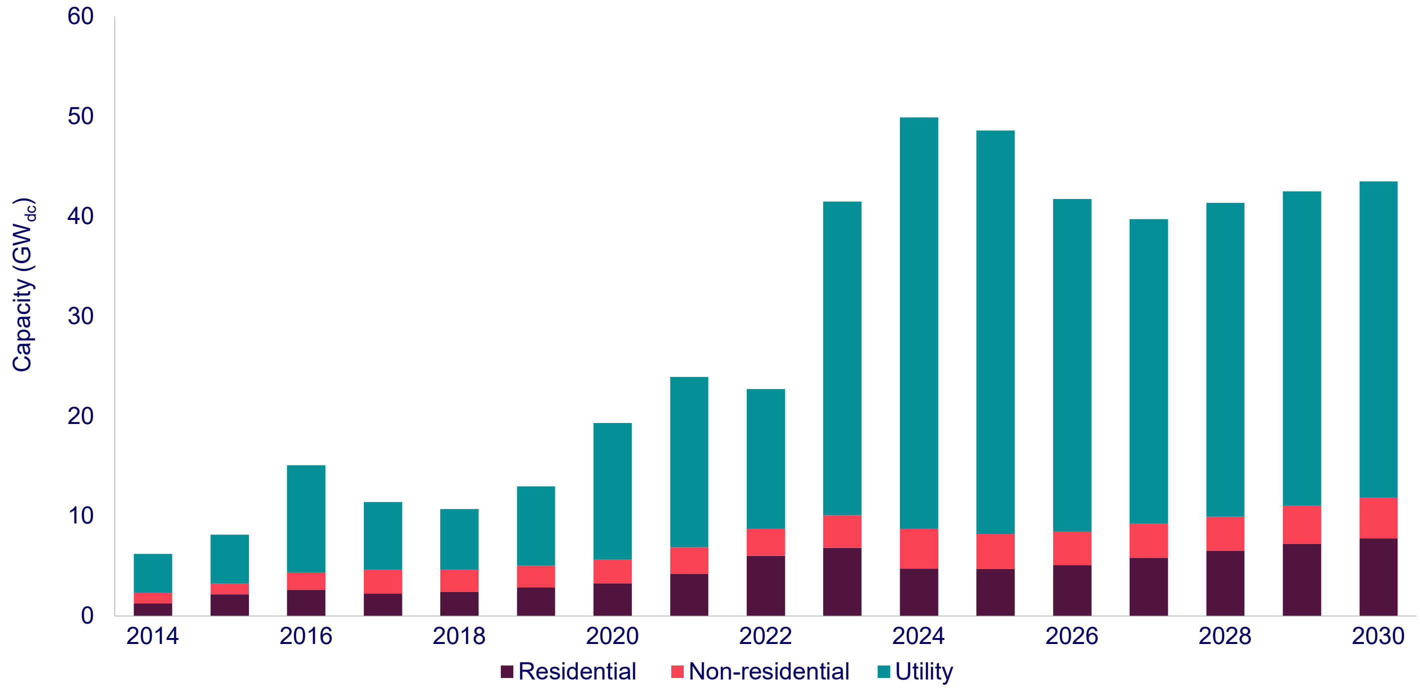
Developers demonstrate resilience in the face of tariff uncertainty

Along with a shift in the political landscape, the utility-scale solar industry is also experiencing uncertainty due to changing tariffs on solar panels and equipment. Wood Mackenzie reports project delays and cancellations, with 4.8 GW_{dc} of projects planned for Q1 2025 postponed and 54% now expected online in 2026. While not all delays are due to tariff changes, the trend shows how policy uncertainty and supply chain issues have negatively impacted project timelines.

Ongoing trade tensions, especially with China, continue to influence policy decisions, creating challenges for developers and manufacturers. This interplay between international trade and domestic energy policy further complicates the market.

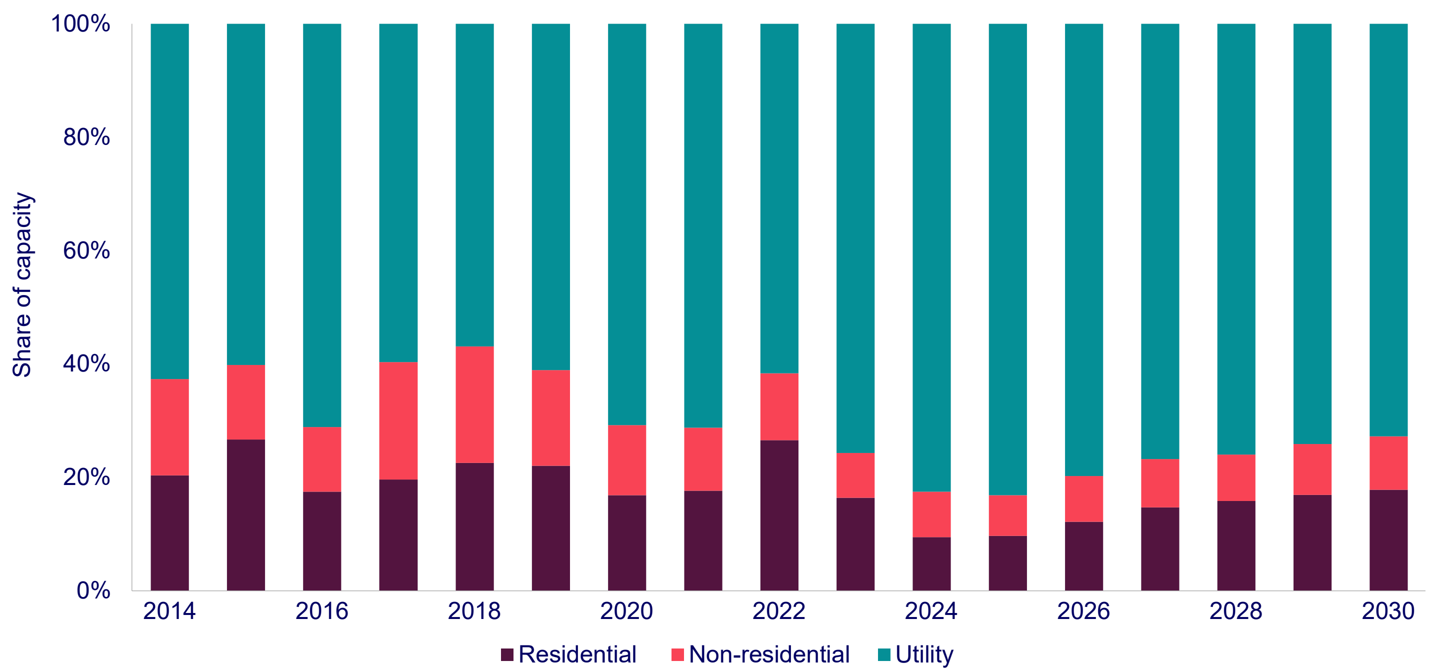
7. US solar PV forecasts

US PV installation historical data and forecast, 2014-2030



Source: Wood Mackenzie

US PV share of capacity historical data and forecast, 2014-2030



Source: Wood Mackenzie

8. National solar PV system pricing

8.1. National average PV installed price estimates

Important notes for understanding Wood Mackenzie's system pricing: National average PV system pricing reflects installed prices for any quarter. Wood Mackenzie assumes all products are procured and delivered in the same year as the installation for all market segments. Wood Mackenzie's Supply Chain data and models are leveraged to enhance and bolster our pricing outlooks. For more details on the assumptions, system size and module for each market segment, see Appendix B.

Wood Mackenzie assumes that all system costs are incurred in the year in which the project is being contracted and no procurement or construction lags are being factored into the pricing. Module prices for all segments are also now reflective of 'overnight' pricing and do not account for any procurement or delivery lags (previously, modules for the utility segment were assumed to be procured one year prior to the project's commercial operation). The utility segment data no longer breaks out taxes as a separate line item as those are incorporated in the equipment category estimates. These changes have been made to the current system prices as well as historical prices in 2023 and onward.

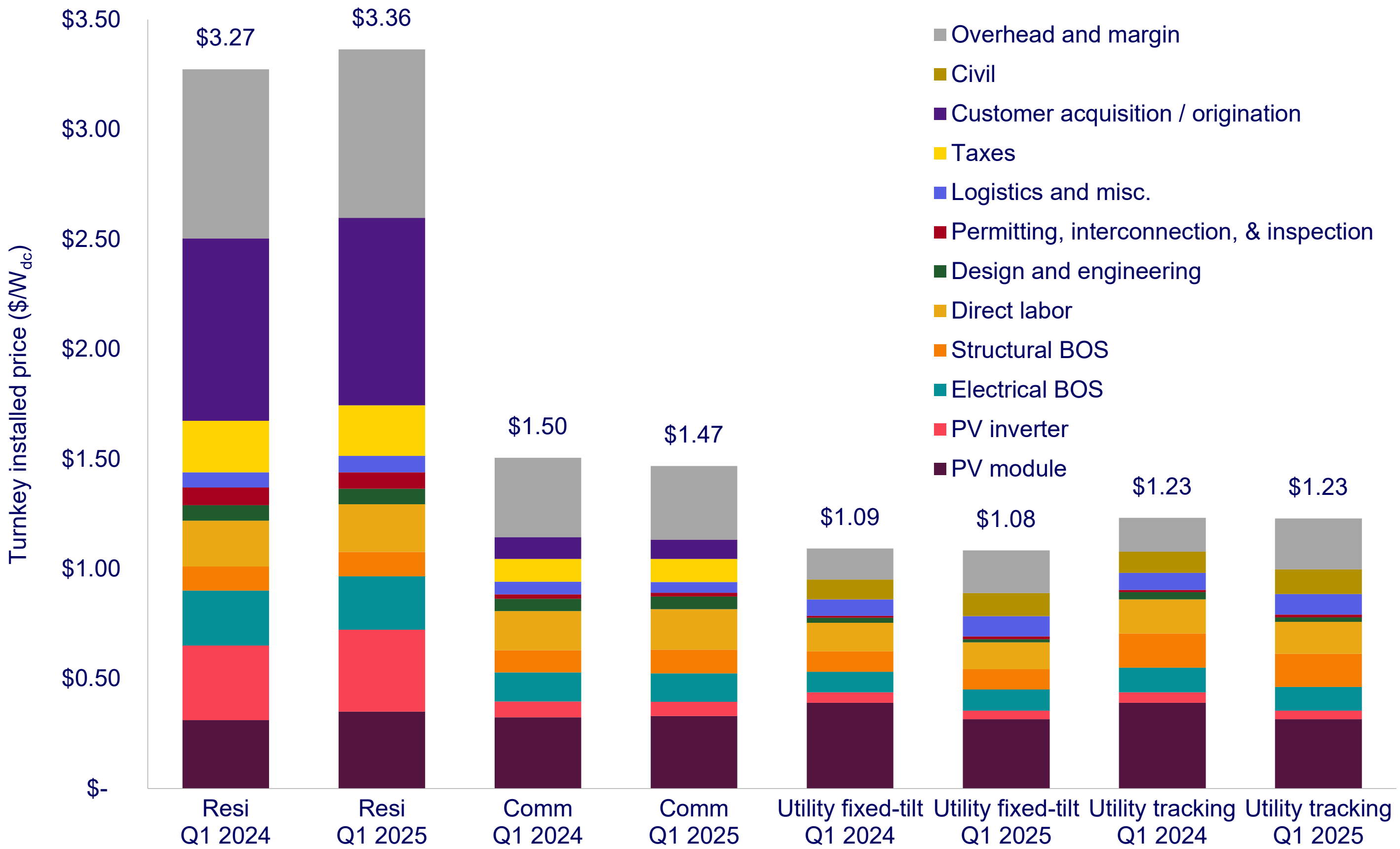
National system pricing increased quarter-over-quarter across all segments, except residential

In Q1 2025, US solar PV system prices showed mixed trends across segments. Residential prices remained stable at $3.36/W_{dc}$, despite a 3% increase in inverter costs as market share shifts to domestic module-level power electronics (MLPE).

Commercial system prices rose 1% quarter-on-quarter to $1.47/W_{dc}$, driven by higher structural balance-of-system costs and module prices and partially mitigated by lower inverter prices and stable labor costs. Module costs increased by an average of 3% in Q1 2025 across all segments following the DOC's preliminary determination in the AD/CVD investigation on PV cells and modules from Cambodia, Malaysia, Thailand, and Vietnam in Q4 2024.

Utility-scale system prices saw greater increases, with fixed-tilt and single-axis tracking systems rising 3% and 4% quarter-over-quarter to $1.08/W_{dc}$ and $1.23/W_{dc}$, respectively. Engineering procurement and construction companies (EPC) faced challenges including labor shortages, extended lead times, and tariff uncertainties, leading to a 20% surge in overhead and margin costs. The adoption of Tunnel Oxide Passivated Contact (TOPCon) modules helps offset some of the cost increases through higher efficiencies, providing savings on labor and balance of plant equipment.

Modeled US national average system prices by market segment, Q1 2024 and Q1 2025



Source: Wood Mackenzie

National average turnkey PV installation/EPC price ($/W$_{dc}$)	Q1 2024	Q1 2025
Residential	$3.27	$3.36
Commercial	$1.50	$1.47
Utility fixed-tilt	$1.09	$1.08
Utility tracking	$1.23	$1.23

Source: Wood Mackenzie

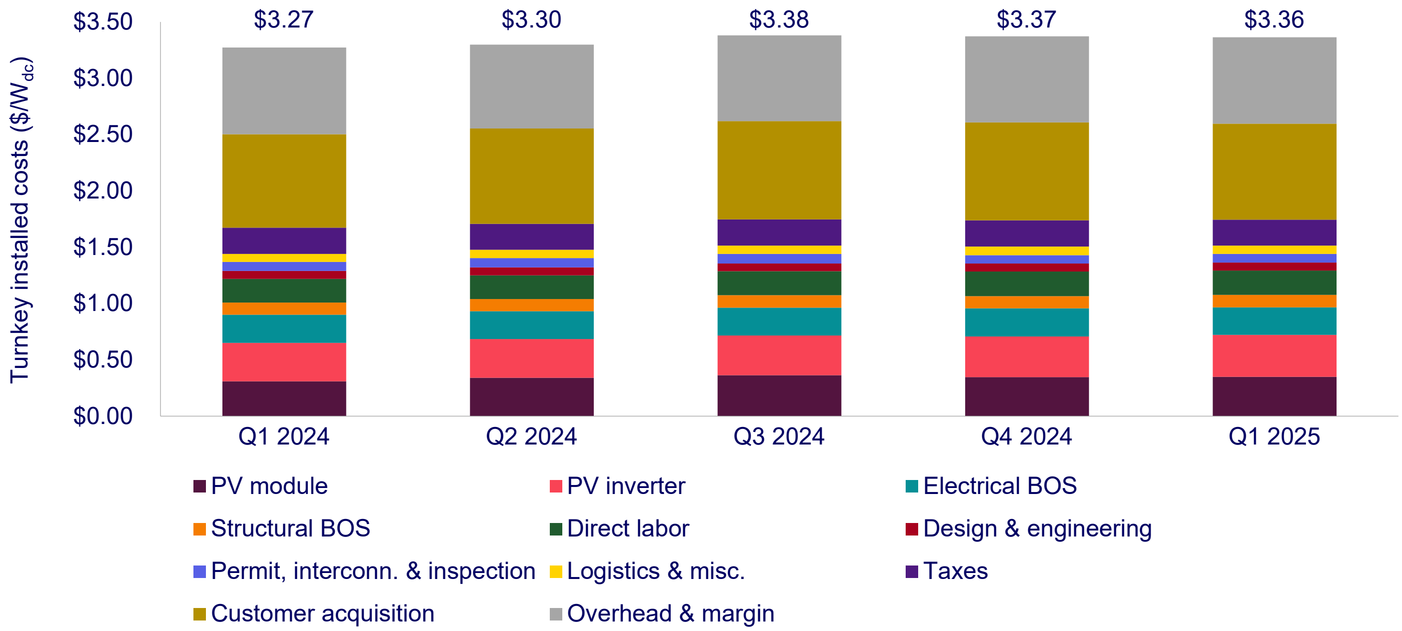
System pricing does not change uniformly in each state market. Differences in the cost of labor, permitting requirements, and geographical characteristics can affect system prices by 20% or more from jurisdiction to jurisdiction. Project-specific design characteristics can add extra variability.

8.2. Residential PV system pricing

Residential PV system costs stayed flat quarter-over-quarter as the market continued to face demand challenges

Residential PV system prices remained relatively stable in Q1 2025 at $3.36/W$_{dc}$. This represented a $0.01/W$_{dc}$ decrease quarter-over-quarter, reflecting a modest 0.2% drop. Inverter prices for the segment climbed 3% quarter-over-quarter, as market share shifted to domestic equipment. Despite the increase in equipment price, the total system price remains relatively stable. The adoption of TOPCon modules contributed to the savings in balance of plant costs, and customer acquisition costs decreased for the first time in at least a year.

Modeled residential turnkey PV system pricing, Q1 2024 – Q1 2025



Source: Wood Mackenzie

US residential PV modeled costs ($/$W_{dc}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
PV module	$0.31	$0.34	$0.36	$0.35	$0.35
PV inverter	$0.34	$0.34	$0.35	$0.36	$0.37
Electrical BOS	$0.25	$0.25	$0.25	$0.25	$0.24
Structural BOS	$0.11	$0.11	$0.11	$0.11	$0.11
Direct labor	$0.21	$0.21	$0.21	$0.22	$0.22
Design and engineering	$0.07	$0.07	$0.07	$0.07	$0.07
Permit, interconnection and inspection	$0.08	$0.08	$0.08	$0.08	$0.08
Logistics and miscellaneous	$0.07	$0.07	$0.07	$0.08	$0.08
Taxes	$0.23	$0.23	$0.23	$0.23	$0.23
Customer acquisition	$0.83	$0.85	$0.87	$0.87	$0.85
Overhead and margin	$0.77	$0.74	$0.76	$0.76	$0.77
National average turnkey pricing	$3.27	$3.30	$3.38	$3.37	$3.36

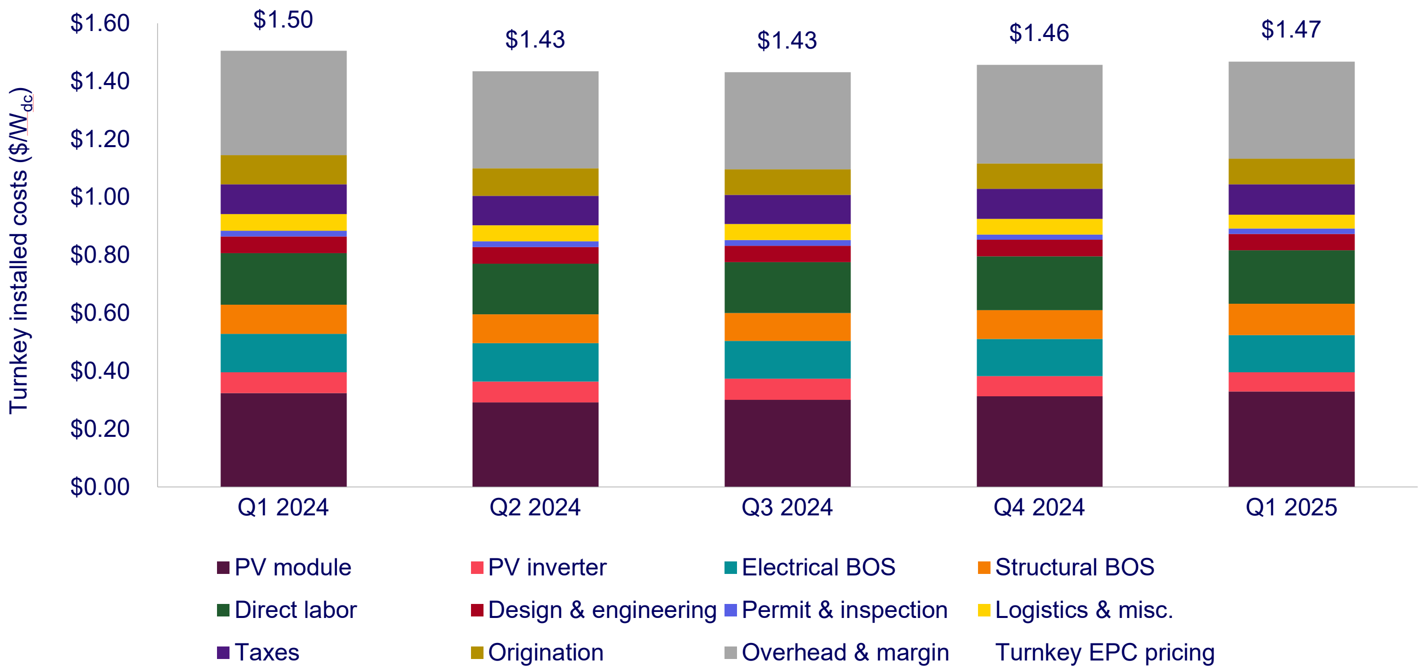
Source: Wood Mackenzie. Assumes 8 kW_{dc} rooftop system, blended average of standard mono PERC PV modules and premium "high-efficiency modules," and microinverter system.

8.3. Commercial PV system pricing

Prices are up 1% quarter-over-quarter as module prices increase 5%

Module prices continued to climb following the DOC's preliminary determination in the Southeast Asia AD/CVD investigation. Structural balance of system costs rose 8% as installers switched to domestic products and racking costs increased due to larger modules. However, three-phase string inverters fell 5% quarter-on-quarter as multiple manufacturers competed for market share. The shift to TOPCon modules provided savings on electrical balance of plant cost. Labor costs remained flat, helping to offset the rise in modules and racking cost. As a result, average commercial system prices landed at $1.47/$W_{dc}$ in Q1 2025, rising by 1% quarter-on-quarter.

Commercial turnkey PV system pricing, Q1 2024 – Q1 2025



Source: Wood Mackenzie

US commercial PV modeled costs ($/$W_{dc}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
PV module	$0.32	$0.29	$0.30	$0.31	$0.33
PV inverter	$0.07	$0.07	$0.07	$0.07	$0.07
Electrical BOS	$0.13	$0.13	$0.13	$0.13	$0.13
Structural BOS	$0.10	$0.10	$0.10	$0.10	$0.11
Direct labor	$0.18	$0.17	$0.18	$0.18	$0.18
Design and engineering	$0.06	$0.06	$0.06	$0.06	$0.06
Permit and inspection	$0.02	$0.02	$0.02	$0.02	$0.02
Logistics and miscellaneous	$0.06	$0.06	$0.06	$0.05	$0.05
Taxes	$0.10	$0.10	$0.10	$0.10	$0.10
Origination	$0.10	$0.10	$0.09	$0.09	$0.09
Overhead and margin	$0.36	$0.33	$0.33	$0.34	$0.33
National average turnkey pricing	$1.50	$1.43	$1.43	$1.46	$1.47

Source: Wood Mackenzie; Note: Assumes a 250-kW low-slope ("flat") roof system, string inverter-based design topology, fully ballasted, aluminum/glass-reinforced composite-based mounting structure, and a rectangular array on membrane roof.

8.4. Utility PV system pricing

Rising EPC costs increase utility-scale system prices by an average of 3% quarter-over-quarter

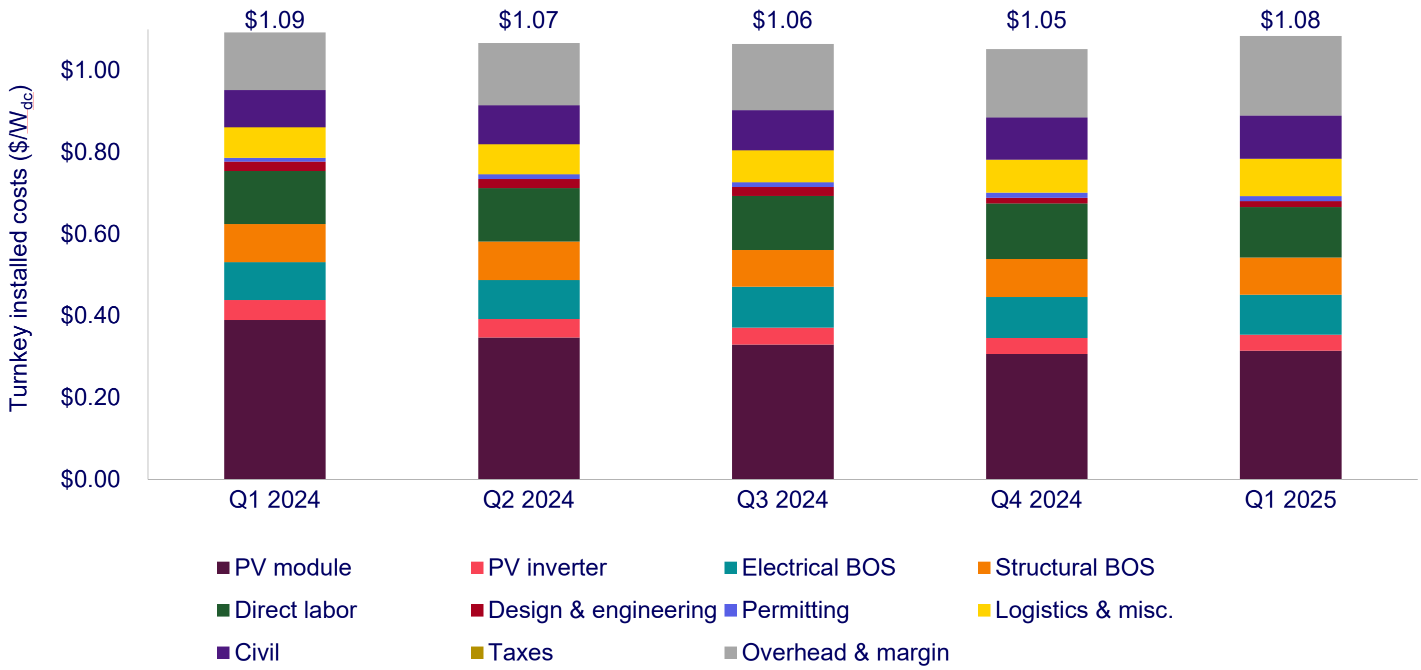
Utility-scale system prices rose in Q1 2025, with fixed-tilt and single-axis tracking systems increasing by 3% and 4% quarter-over-quarter, respectively. Utility fixed-tilt system costs were $1.08/$W_{dc}$, and single-axis tracking system costs were $1.23/$W_{dc}$ in Q1 2025.

EPCs face ongoing challenges, including labor shortages and extended equipment lead times for high voltage equipment. These issues are compounded by uncertainties from tariff changes on steel, iron, and imports from Canada and Mexico, announced in February 2025 (and later updated in June 2025). The administrative burden of ensuring prevailing wage compliance and meeting domestic content requirements adds to EPC overhead. Consequently, EPC costs have surged quarterly by an average of 20% across utility-scale fixed-tilt and single-axis tracking systems, reflecting increased risks and complex contract negotiations.

Module prices climbed 4% in Q1 2025, following the DOC's preliminary determination in the AD/CVD investigations into PV cells and modules from Cambodia, Malaysia, Thailand, and Vietnam in Q4 2024. Average module prices reached $0.32/$W_{dc}$ in Q1 2025, up from US$0.30/$W_{dc}$ in Q4 2024.

Similar to the distributed segment, the shift towards TOPCon technology has partially offset these cost increases. Larger, more efficient modules yield savings on balance of equipment and labor costs, helping to mitigate the impact of rising module prices.

Utility turnkey fixed-tilt PV system pricing, Q1 2024 – Q1 2025

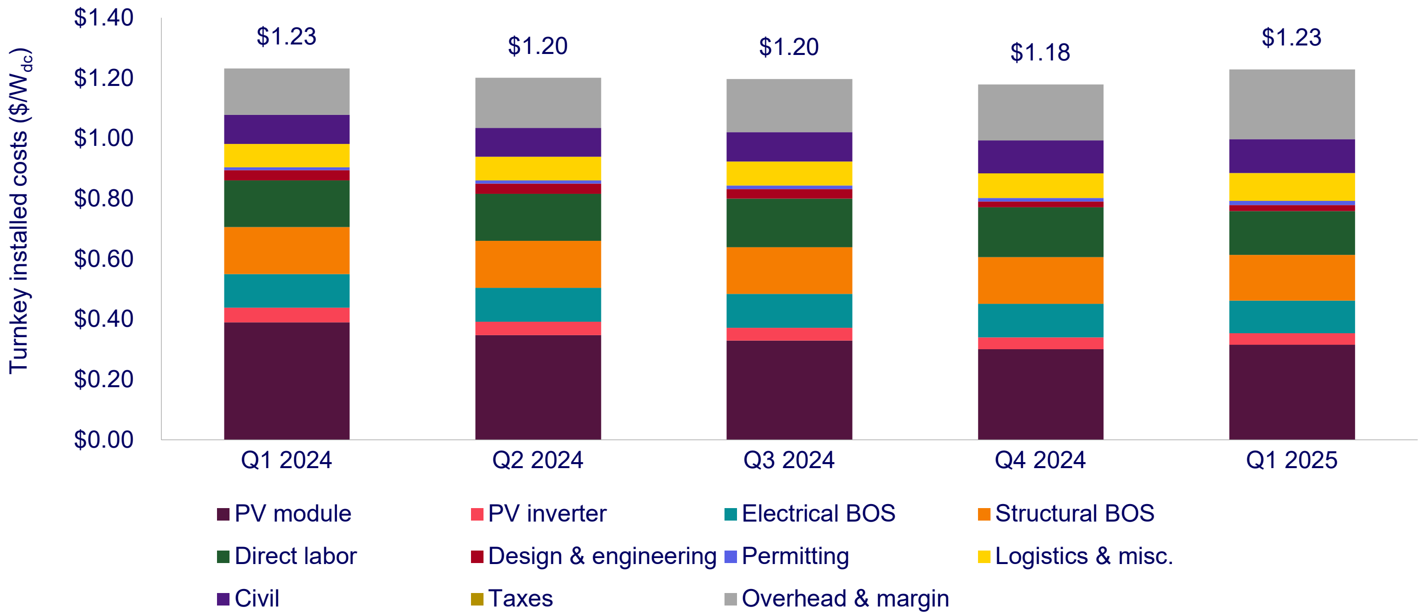


Source: Wood Mackenzie

US fixed-tilt PV modeled costs ($/$W_{dc}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
PV module	$0.39	$0.35	$0.33	$0.31	$0.32
PV inverter and alternating current (AC) subsystem	$0.05	$0.04	$0.04	$0.04	$0.04
Electrical BOS	$0.09	$0.10	$0.10	$0.10	$0.10
Structural BOS	$0.09	$0.09	$0.09	$0.09	$0.09
Direct labor	$0.13	$0.13	$0.13	$0.14	$0.12
Design and engineering	$0.02	$0.02	$0.02	$0.01	$0.01
Permitting	$0.01	$0.01	$0.01	$0.01	$0.01
Logistics and miscellaneous	$0.07	$0.07	$0.08	$0.08	$0.09
Civil	$0.09	$0.10	$0.10	$0.10	$0.11
Overhead and margin	$0.14	$0.15	$0.16	$0.17	$0.19
National average turnkey pricing	$1.09	$1.07	$1.06	$1.05	$1.08

Source: Wood Mackenzie; Note: Assumes a 10 MW_{dc} utility system with central inverters and steel-based fixed-tilt system with pile-driven foundations.

Utility turnkey single-axis tracking PV system pricing, Q1 2024 – Q1 2025



Source: Wood Mackenzie

US single-axis tracking PV modelled costs ($/$W_{dc}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
PV module	$0.39	$0.35	$0.33	$0.30	$0.32
PV inverter and AC subsystem	$0.05	$0.04	$0.04	$0.04	$0.04
Electrical BOS	$0.11	$0.11	$0.11	$0.11	$0.11
Structural BOS	$0.16	$0.16	$0.16	$0.15	$0.15
Direct labor	$0.15	$0.16	$0.16	$0.16	$0.14
Design and engineering	$0.03	$0.03	$0.03	$0.02	$0.02
Permitting	$0.01	$0.01	$0.01	$0.01	$0.01
Logistics and miscellaneous	$0.08	$0.08	$0.08	$0.08	$0.09
Civil	$0.10	$0.10	$0.10	$0.11	$0.11
Overhead and margin	$0.15	$0.17	$0.18	$0.19	$0.23
National average turnkey pricing	$1.23	$1.20	$1.20	$1.18	$1.23

Source: Wood Mackenzie. Note: Assumes a 10 MW_{dc} utility system with central inverters and steel-based pile-driven foundations and horizontal single-axis tracking.

9. Manufacturing

9.1. Polysilicon

The domestic solar-grade polysilicon industry has seen little movement compared to downstream components. Hemlock Semiconductor and Wacker Chemie are the only remaining US producers of this component since REC Silicon shut down its Moses Lake factory at the end of 2024. REC Silicon had restarted the factory just a year earlier, but it neither ramped up to full production nor delivered a product due to quality concerns.

Highland Materials is the only other company that has publicly announced plans to manufacture solar-grade polysilicon in the US. The company has said its Tennessee factory is expected to start construction in 2026 and begin production in late 2027.

US polysilicon manufacturing capacity, MT, Q3 2023 – Q1 2025

Polysilicon	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Total capacity available in the US	41,500	45,100*	48,700*	52,300*	55,900*	41,500*	41,500

*Source: Wood Mackenzie; Note: *Estimated value based on splitting REC Silicon's 18,000 MT capacity in Moses Lake across 5 quarters during expected ramp-up period. The facility's immediate closure was announced in December 2024, so this capacity was removed in Q4 2024.*

9.2. Wafers

The US has not yet onshored solar wafer production, although Qcells and Corning plan to do so in the second half of 2025.

In January, the Treasury released additional guidance for the domestic content bonus adder. The updated safe harbor table includes an additional column for projects using modules made with domestic cells and domestic wafers; it offers higher value to such products than those relying on imported wafers. However, because use of this column is optional, this incentive is not likely to encourage wafer manufacturing. Solar cells, combined with easier-to-source components such as trackers and racking, are valuable enough to meet the domestic content thresholds even without US-made wafers. However, the added value could tip the scales in some blended projects. It should be noted, however, that this guidance is not a final rule and could be changed.

9.3. Cells

Note: In this report series, thin-film solar facilities producing modules through monolithic integration are not defined as cell producers.

ES Foundry became the second US cell manufacturer when its South Carolina factory began production in January, bringing domestic cell manufacturing capacity to 2 GW. This could increase to 9.3 GW by the end of 2025, as ES Foundry plans to expand its capacity and Qcells and Silfab anticipate bringing their factories in Georgia and South Carolina online respectively. Boviet Solar, Canadian Solar, Talon PV, and others have announced plans to begin US cell production in 2026 or later.

The DOC released the final AD/CVD rates for solar cells from Cambodia, Malaysia, Thailand, and Vietnam (CMTV) in April, and the ITC finalized the tariffs with an affirmative determination in May. The rates are prohibitively high in many cases. The viability of US factories could depend on how the 45X manufacturing tax credit is treated in the final reconciliation bill. The complex FEOC language in the House version of the bill may make it difficult for many companies to claim the 45X credits, even if they are not directly headquartered in China. Without this incentive, it may be difficult for US manufacturers to remain competitive.

US cell manufacturing capacity, MW, Q3 2023 – Q1 2025

Crystalline silicon	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Total capacity available in the US	0	0	0	0	1,000	1,000	2,000

Source: Wood Mackenzie

9.4. Modules

US module manufacturing capacity reached more than 51 GW in Q1, an unprecedented number. At full utilization, these factories could produce enough modules for the entire domestic market. Even so, several manufacturers still plan to expand or build more factories. If these plans all materialize, the US could reach up to 88 GW of capacity by the end of 2025. However, the actual number is likely to be lower since many of these announced factories are not currently under construction.

That said, tariffs and potential changes to the IRA could make domestic manufacturing more difficult in the coming years. While tariffs like the AD/CVD on Cambodia, Malaysia, Thailand, and Vietnam restrict module import options, they also restrict cell supply options for US module manufacturers. Due to the limited domestic cell manufacturing capacity, US module manufacturers largely rely on imported cells. In 2024, 60% of cell imports came from CMTV. India, Indonesia, Laos, and South Korea, the other major potential cell suppliers to the US, face Liberation Day tariffs. Though these tariffs were recently deemed illegal by the US Court of International Trade, the Trump administration has appealed the ruling, and the case remains under litigation. General uncertainty around tariffs is making bill of materials procurement challenging for domestic module manufacturers.

Other important module components are also mostly imported and thus potentially subject to high tariffs. The Section 232 tariffs on steel and aluminum cover frames, while the Liberation Day tariffs, if implemented, would likely impact glass and other components.

Additionally, the budget reconciliation bill passed by the House introduces complex FEOC restrictions for the 45X manufacturing tax credit. The current language would prevent a significant number of US manufacturers from receiving the credit, calling the viability of their factories into question. The draft bill would also end transferability after 2027. This could create difficulty for manufacturers, many of which rely on transferring tax credits to monetize the 45X credits.

US module manufacturing capacity and production, MW, Q3 2023 – Q1 2025

Crystalline silicon	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Total capacity available in the US	7,651	9,951	15,291	23,491	28,729	31,879	40,529
Quarterly production	866	1,278	1,508	2,818	3,591	5,079	4,178
Thin-film modules	**Q3 2023**	**Q4 2023**	**Q1 2024**	**Q2 2024**	**Q3 2024**	**Q4 2024**	**Q1 2025**
Total capacity available in the US	3,600	5,900	5,900	6,900	10,600	10,600	10,600
Quarterly production	698	1,320	1,207	1,411	1,686	2,404	2,304
Total	**Q3 2023**	**Q4 2023**	**Q1 2024**	**Q2 2024**	**Q3 2024**	**Q4 2024**	**Q1 2025**
Total capacity available in the US	11,251	15,851	21,191	30,291	39,329	42,479	51,129
Quarterly production	1,564	2,598	2,715	4,229	5,277	7,483	6,482

Source: Wood Mackenzie

Capacity of operational US module manufacturing facilities, MW, 2023 – Q1 2025

Company	Headquarters	Facility state	Facility city	2023 Capacity	2024 Capacity	Q1 2025 Capacity
Ascent Solar	US	Colorado	Thornton	5	5	5
Auxin Solar	US	California	San Jose	150	150	150
Canadian Solar	Canada	Texas	Mesquite	-	5,000	5,000

CHERP Solar Works	US	California	Pomona	14	14	14
Crossroads Solar	US	Indiana	South Bend	12	50	50
Energy America	US	California		500	500	500
Energy America	US	South Carolina		-	1,000	1,000
First Solar	US	Ohio	Perrysburg	600	600	600
First Solar	US	Ohio	Lake Township	5,300	6,500	6,500
First Solar	US	Alabama	Trinity	-	3,500	3,500
GAF Energy	US	California	San Jose	50	50	50
GAF Energy	US	Texas	Georgetown	-	250	250
Hanwha Qcells	South Korea	Georgia	Dalton	5,100	5,100	5,100
Hanwha Qcells	South Korea	Georgia	Cartersville	-	3,300	3,300
Heliene	Canada	Minnesota	Mountain Iron	300	300	300
Heliene	Canada	Minnesota	Mountain Iron	500	500	500
Hightec Solar	US	Indiana	Michigan City	-	100	100
Hounen Solar	China	South Carolina	Orangeburg	-	1,000	1,000
Illuminate USA	US	Ohio	Pataskala	-	5,300	5,300
Imperial Star Solar	Cambodia	Texas	Tomball	-	-	2,000
JA Solar	China	Arizona	Phoenix	-	-	2,000
JinkoSolar	China	Florida	Jacksonville	400	1,000	1,000
Merlin Solar	US	California	San Jose	5	5	5
Meyer Burger	Germany	Arizona	Goodyear	-	1,000	1,000
Mission Solar Energy	US	Texas	San Antonio	500	500	500
Runergy	China	Alabama	Huntsville	-	2,000	2,000
SEG Solar	US	Texas	Houston	-	1,000	2,000
Silfab	Canada	Washington	Burlington	400	400	400
Silfab	Canada	Washington	Bellingham	400	400	400
Sinotec Solar	China	California	City of Industry	300	300	300
Sirius PV	Turkey	Texas	Brookshire	-	1,000	1,000
Solar4America	US	California	Sacramento	1,300	1,300	-
Suntegra	US	New York	Binghamton	10	10	10
T1 Energy	US	Texas	Wilmer	-	350	1,400
US Modules Powered by CIG	US	Texas	College Station	-	-	1,000
Waaree Energies	India	Texas	Brookshire	-	-	1,600

Source: Wood Mackenzie

10. Component pricing

10.1. Polysilicon, wafers, cells, and modules

Polysilicon prices rose slightly in Q1 as manufacturers continue to operate at lower utilization, but they are still low compared to 2023 and early 2024 prices. Chinese polysilicon rose from $4.71/kg to $5.36/kg, while non-Chinese polysilicon rose from $17.23/kg to $18.59/kg. Despite this increase, n-type wafers and TOPCon cells made with the latter material remained stable at $0.05/W and $0.07/W, respectively. Weak demand kept these prices from rising.

Modules delivered to the US from Southeast Asia experienced steep price increases quarter-over-quarter as the impacts of the AD/CVD case on solar cells and modules from Cambodia, Malaysia, Thailand, and Vietnam continued to hit the market. After being priced in the mid-to-high $0.20s/W throughout 2024, Southeast Asian PERC modules reached $0.30/W in Q1, and TOPCon modules rose to $0.34/W. In Q1 2025, the US imported only 6.6 GW of modules, representing a 55.8% decrease from a year prior.

Although imported solar cells are also subject to the AD/CVD on CMTV, US-made module prices slightly declined in Q1. Utility-scale PERC modules dropped from $0.32/W to $0.30/W, while PERC modules for the distributed generation segment fell from $0.35/W to $0.33/W. Malaysia (which has a relatively low country-wide AD/CVD rate), South Korea, Indonesia, and Laos are major suppliers of cells to the US. Additionally, a significant amount of manufacturing capacity came online towards the end of 2024 and the beginning of 2025, intensifying competition. Domestic module production reached record highs in the past two quarters: 7.5 GW and 6.5 GW in Q4 2024 and Q1 2025, respectively.

Polysilicon, wafer, cell, and module prices, $/W, Q1 2024 – Q1 2025

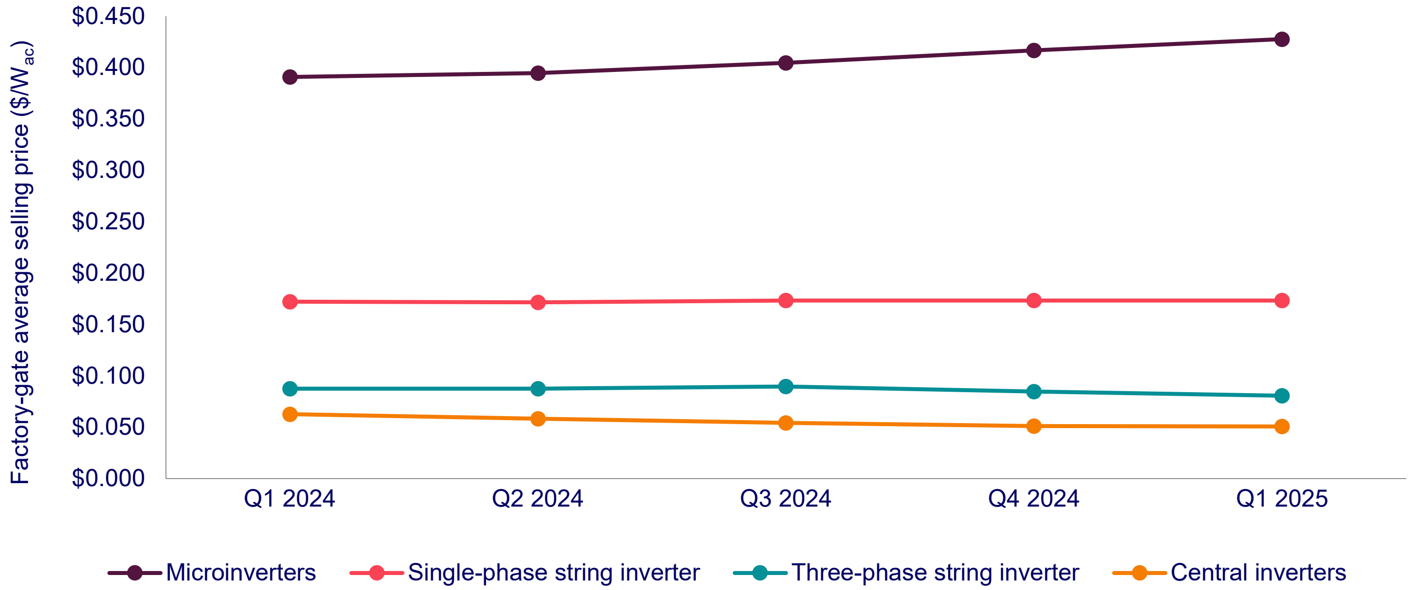
Global components - spot price	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Non-Chinese polysilicon ($/kg)	$18.59	$18.44	$17.73	$17.23	$18.59
N-type wafer with non-Chinese polysilicon - M10	$0.06	$0.05	$0.05	$0.05	$0.05
TOPCon cell with non-Chinese polysilicon - M10	$0.10	$0.09	$0.10	$0.09	$0.09
TOPCon module, FOB China Port - M10	$0.13	$0.11	$0.10	$0.10	$0.10
Mono PERC module, DDP to the US from SEA - M10	$0.27	$0.26	$0.28	$0.26	$0.30
TOPCon module, DDP to the US from SEA - M10	$0.27	$0.27	$0.29	$0.29	$0.34
Mono PERC module, EXW US factory (utility) - M10	$0.33	$0.32	$0.33	$0.32	$0.30
Mono PERC module, EXW US factory (DG) - M10	$0.37	$0.35	$0.36	$0.35	$0.33

10.2. Inverter pricing

The microinverter market is shifting toward domestic production, as the leading manufacturer in this segment, Enphase now supplies the market with domestically produced equipment. Microinverter prices increased by 3% quarter-over-quarter and almost 10% year-over-year, landing at $0.43/W_{ac}$ in Q1 2025. Conversely, pricing for residential single-phase string inverters stayed flat at $0.17/W_{ac}$ in Q1 2025.

Three-phase string inverters are down 5% quarter-over-quarter in Q1 2025, landing at an average of $0.08/W_{ac}$. Strong market competition continues to drive prices down for the segment. Central inverter pricing was down 1% in Q1 2025 compared to Q4 2024. Compared to year-over-year, central inverter prices are down almost 20%. Manufacturers continue to increase the power density for these inverters, driving down the average selling price, which reached $0.051/W_{ac}$ in Q1 2025.

Factory-gate PV inverter pricing, Q1 2024 – Q1 2025 ($/$W_{ac}$)



Source: Wood Mackenzie.

National average price ($/$W_{ac}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Microinverters	$0.391	$0.395	$0.405	$0.417	$0.428
Single-phase string inverter	$0.172	$0.172	$0.173	$0.173	$0.173
Three-phase string inverter	$0.087	$0.087	$0.090	$0.085	$0.081
Central inverters	$0.063	$0.058	$0.054	$0.051	$0.051

Source: Wood Mackenzie

10.3. Mounting structure pricing

Factory-gate pricing for PV mounting structures continues to vary significantly depending on market segment, geography, configuration, layout, and project size, all of which complicate the calculation of an “average” cost.

For simplicity’s sake, the values reported below reflect the costs of the mounting structures of the following system types:

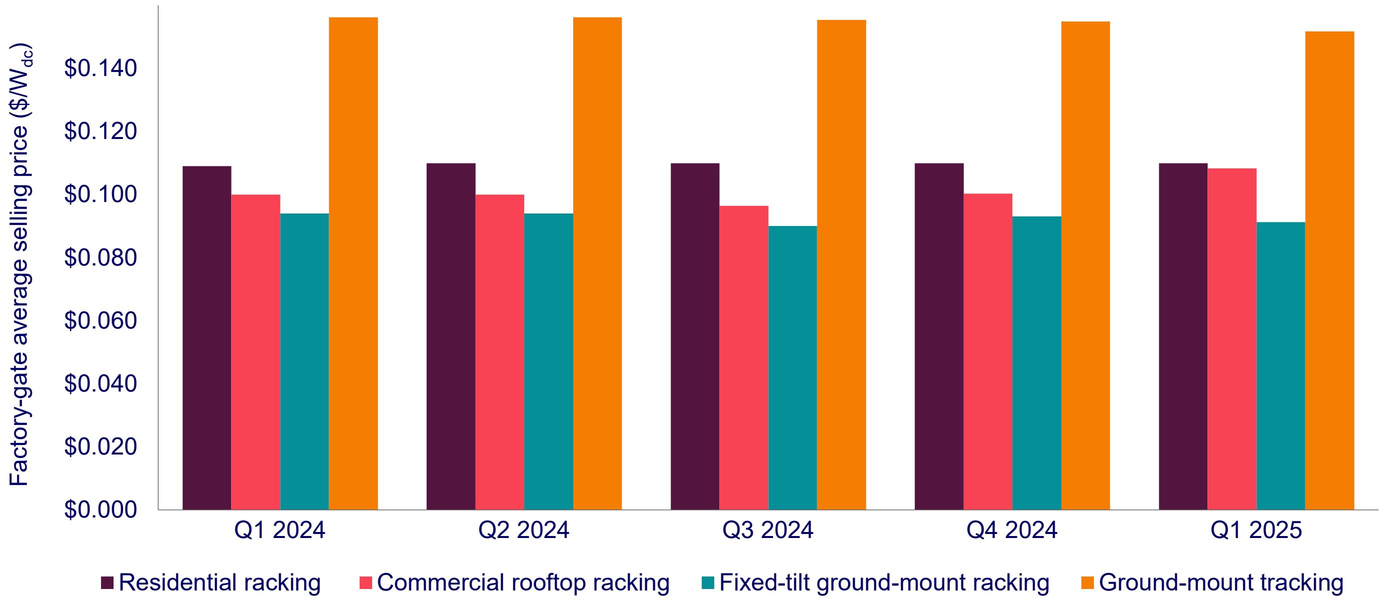
- **Residential rooftop: 5 kW to 10 kW sloped roof in California using a clamp-and-rail-based system.**
- **Commercial rooftop: 100 kW to 500 kW flat-roof ballasted system in low-wind areas requiring no additional structural support.**
- **Ground-mount fixed-tilt: 10 MW fixed-tilt ground-mount system in low-wind areas.**
- **Ground-mount one-axis tracking:** 10 MW horizontal single-axis tracking ground-mount system in low-wind areas.

Even with these baselines, PV mounting structure buyers should consider the total implied cost from individual manufacturers rather than relying on the national average costs. Differences in racking materials and design have implications for labor costs, grounding requirements, and the need for additional structural support.

Residential racking stayed flat quarter-over-quarter, with average pricing of $0.11/$W_{dc}$ in Q1 2025. Comparatively, pricing for commercial rooftop racking systems increased by 8% quarterly, as a shift in module technology resulted in larger module sizes, reaching $0.11/$W_{dc}$.

Ground-mount racking is largely dominated by domestic manufacturers as owners want to qualify their systems for the domestic content bonus adder and satisfy the iron and steel requirements. Fixed-tilt racking and single-axis trackers averaged $0.09/$W_{dc}$ and $0.15/$W_{dc}$, respectively, in Q4 2024. Pricing declined by 2% for both fixed-tilt and racking systems as module efficiencies lower prices on a dollar-per-watt basis.

Factory-gate PV racking pricing, Q1 2024 – Q1 2025 ($/W$_{dc}$)



Source: Wood Mackenzie.

National average price ($/W$_{dc}$)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Residential racking	$0.109	$0.110	$0.110	$0.110	$0.110
Commercial rooftop racking	$0.100	$0.100	$0.096	$0.100	$0.108
Fixed-tilt ground-mount racking	$0.094	$0.094	$0.090	$0.093	$0.091
Ground-mount tracking	$0.156	$0.156	$0.155	$0.155	$0.152

Source: Wood Mackenzie

11. Appendix A: Definitions and conversions

11.1. Photovoltaics

We report PV capacity data in watts of direct current (DC) under standard test conditions. This is the metric most used by suppliers, developers and program administrators. However, some program administrators report data in 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 MW_{ac} and a 77% DC-to-AC derate factor for systems greater than 10 MW_{ac} based on data from existing systems, conversations with installers, and averages from California Solar Initiative data.

11.2. Residential photovoltaic system

A residential PV installation is defined as a project in which the offtaker of the power is a single-family household. Any PV system installed on a homeowner's property that participates in a feed-in tariff program is considered residential even if the offtaker of the power is a utility.

11.3. Commercial photovoltaic system

Rather than using a capacity cutoff to differentiate between residential, commercial and utility systems, Wood Mackenzie defines a system according to its contracted power offtaker. A commercial PV installation is defined as a project in which the offtaker of the power is a “non-residential” customer – neither a homeowner nor a utility. The spectrum of offtakers typically includes commercial, industrial, agricultural, school, government and nonprofit customers. Importantly, we exclude customer-sited projects that sell power to a utility through a feed-in tariff or power purchase agreement, as the ultimate power offtaker is the utility and not the onsite customer. Examples of excluded projects include the Qualifying Facilities projects in the Massachusetts SMART program and the REDI program projects in Georgia. These are included in the utility-scale segment.

While most commercial solar projects under this definition will be connected behind-the-meter on the customer’s property, there are clearly exceptions such as remotely net-metered projects with non-residential offtakers.

11.4. Community photovoltaic system

Community solar projects are those where multiple customers can subscribe to power offtake from a project installed in their community and receive credits on their utility bills. These projects are further subdivided into “third-party-led” community solar, where projects are built and operated by third parties, and “utility-led” community solar, where projects are procured or built by utilities. (See our community solar publications for more details on this distinction). In either case, community solar projects are typically “anchored” by commercial customers, but this can vary depending on the program structure.

11.5. Utility photovoltaic system

A utility PV installation is a project in which the offtaker of the power is a utility, a third-party power supplier, or a commercial/industrial entity. Projects with commercial/industrial entities as the power offtakers are only considered utility-scale if the projects are front-of-the-meter and connected to the transmission system. These projects are also referred to as “corporate offsite” projects. Utility PV projects also include any PV systems 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.

12. Appendix B: Methodology and data sources

Please note that data from previous quarters is sometimes updated because of improved or modified 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.

12.1. Historical installations

Quarterly state-by-state data on PV installations is collected primarily from utility interconnection datasets, as well as state agencies, incentive program administrators, and third-party contractors. For larger projects not included in these programs, Wood Mackenzie 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 before 2010, Wood Mackenzie also used data collected by Larry Sherwood at the Interstate Renewable Energy Council.

Distributed solar-plus-storage market sizes are calculated by applying an attachment rate to the count of solar installations determined using the solar methodology above. Attachment rates are derived directly from project-level data and supplemented with EIA data or best estimates where there is no project-level data available.

12.2. Forecasts and methodology

Wood Mackenzie uses a bottom-up methodology that evaluates historical installation data and trends by state and market segment to inform our national and state-level US solar forecasts. Our methodology includes a combination of quantitative and qualitative inputs. The quantitative inputs include analysis of project pipelines as well as assessments of the economic competitiveness of solar in each market (such as the levelized cost of electricity compared to retail rates). The qualitative inputs allow us to incorporate revisions based on regulation, policy, or other market intelligence we receive from conversations with industry stakeholders. The specific factors that we evaluate and incorporate into our forecast vary by segment. All forecasts are updated on a quarterly basis and are aligned to Wood Mackenzie's North America Long-Term Outlook from the North America Power Service.

Our Base case outlooks generally assume "business as usual" for factors such as policy changes, project pipelines, and module supply. Importantly, our Base case outlooks assume current policy conditions and don't incorporate any potential policy changes or programmatic expansions. We also periodically create alternative scenarios with specific assumptions to characterize the potential impacts of market uncertainties. In these alternative scenarios, we consider factors such as the outcomes of future equipment supply and demand imbalances, trends in retail rates for distributed solar, or labor and tax equity availability for utility-scale solar. The specific assumptions for alternative scenarios vary, and we define those assumptions within the associated reports where scenarios are published. We generally publish alternative scenarios in each year-in-review report unless otherwise noted.

Residential solar forecast methodology

We update our US distributed solar forecasts for the residential segment quarterly based on the factors below:

- **Most recent historical data and trends:** We analyze the performance of our forecast relative to updated historical data for all states and segments to determine whether our near-term forecasts are in line with current market dynamics. This also allows us to check total deployments against our estimates of the total addressable market to monitor market penetration and saturation.
- **Conversations with industry stakeholders:** We maintain a large network of industry contacts that include installers, EPCs, advocacy organizations, finance providers, technology vendors, and others. These stakeholders have visibility into the on-the-ground realities of the market as well as their own strategic planning around market growth. We coordinate off-the-record conversations with these contacts each quarter to gauge the current dynamics of the market, gather intelligence on how pipelines are (or aren't) growing, and learn of any forthcoming changes to the market.

- **Regulatory updates and retail rate changes:** We monitor regulatory and legislative proceedings for current and forthcoming changes that may impact the market such as incentives, barriers, rate reforms, or changes to net energy metering. As these changes are finalized, their anticipated impacts on the market are incorporated into our outlooks.
- **Market penetration:** We evaluate historical and expected levels of state market penetration to inform our forecasts and assess their viability. For example, we expect markets with higher levels of market penetration to experience slower or negative growth rates. We calculate market penetration by state by dividing our residential solar installation and forecast data by reported owner-occupied single-family homes from the US Census. We assume that 83% of owner-occupied homes are suitable to install rooftop solar, per a study by NREL. We project growth in owner-occupied homes by applying state-level population growth forecasts from Wood Mackenzie's Macroeconomics team.
- **Assessment of economic competitiveness:** Wood Mackenzie routinely analyzes the levelized cost of electricity (LCOE) for key energy technologies, including solar. We periodically assess the residential solar LCOE against retail rates to determine the economic competitiveness of solar in a given market.

Non-residential (commercial and community) solar forecast methodology

Commercial and community solar forecasts are updated quarterly. Similar to residential solar, historical data and trends as well as conversations with industry stakeholders are key factors influencing our forecast updates. Other factors unique to the commercial and community solar segments include:

- **Pipeline data and program interconnection queues:** For commercial and community solar segments, we have solar project pipeline data for most of the largest state markets. We monitor project pipelines from state-level program datasets and interconnection queues to calculate the pace of near-term commercial and community solar additions (for example, datasets from the Massachusetts SMART program or the NYSERDA NY-Sun program). For community solar, we also utilize bi-annual surveys with self-reported pipeline data from over a dozen prominent community solar developers. We then discount these pipelines based on our expectations of project completions and any other relevant market intelligence we receive.
- **Regulatory updates:** We monitor regulatory and legislative proceedings for current and forthcoming changes that may impact the market such as incentives, barriers, rate reform, or changes to net energy metering. For community solar, this includes tracking any legislation related to or impacting statewide community solar programs, including any new legislation introduced that would create new community solar state markets. This research is supplemented by quarterly conversations with the regional policy directors at the Coalition for Community Solar Access (CCSA).
- **Market penetration:** We consider historical and expected levels of state market penetration to inform our forecasts and assess their viability. For example, we expect markets with higher levels of market penetration to experience slower or negative growth rates. For commercial buildings, we calculate market penetration by state by dividing our non-residential solar installation data by building data obtained from StationA. This penetration calculation accounts for commercial customers with community solar subscriptions since these customers have already "gone solar" even if they do not have onsite solar. StationA building data was obtained for 2019 and accounts for buildings with at least 10,000 square feet of rooftop space, which is roughly equivalent to the space needed to support a 70 kW system. We project growth in commercial buildings using state-level gross domestic product (GDP) growth rates from Wood Mackenzie's Macroeconomics team.

Utility-scale solar forecast methodology

We update our US utility-scale solar forecasts based on our visibility into each state's utility solar project pipeline, updates to economic attractiveness by state, and the total addressable market. The total addressable market is calculated based on factors such as labor availability, load growth, supply chain constraints, project economics, and tax equity availability.

The near-term forecasts (years 1-3) are primarily based on our visibility into the utility solar project pipeline, while the longer-term forecasts (years 4-5) also incorporate an assessment of the economic attractiveness of solar and the total addressable market. We maintain a high-quality, comprehensive database of all utility-scale solar projects operating and under development in the US, incorporating updated pipeline information from top developers, utilities, and EPCs quarterly. This project database serves as the foundation of our forecast. We update our US utility-scale forecasts quarterly based on the below factors:

- **Project pipelines:** We monitor project pipelines to calculate the pace of near-term utility-scale project additions. We then discount these pipelines based on the project's stage of development, when the project is expected to come online, our expectations of project completions, and any other relevant market intelligence we receive.
- **Utility solar adders:** In addition to utilizing the concrete pipeline data from our databases, we also assume a certain amount of pipeline growth ("adders"). This pipeline growth shapes the longer-term forecasts and is based on our visibility into additional RPS requirements and utility Integrated Resource Plans (IRP).
- **Conversations with industry stakeholders:** We maintain a large network of industry contacts that include developers, utilities, EPCs, advocacy organizations, finance providers, technology vendors, and others. These stakeholders have visibility into current market dynamics as well as their own strategic planning around market growth. We coordinate conversations with these contacts each quarter to gauge the status of the market and learn of any forthcoming changes to the market.
- **Regulatory updates:** We monitor regulatory and legislative proceedings for current and forthcoming changes that may impact the market. This includes transmission proceedings, revisions to RPS requirements, or interconnection queue reforms by FERC and various ISOs.
- **Updates to project economics models:** We then incorporate utilities' IRPs, generation mix per region, power plant retirements, technology evolution, and other factors into our project economics models. This process determines changes to the attractiveness of utility solar in each market. The forecast is aligned to Wood Mackenzie's North America Long-Term Outlook, and total solar buildout is validated alongside the results of an hourly dispatch model, including alignment to regional power prices and reserve margin levels.
- **Limiting Factors:** Finally, we calculate the impacts from multiple potential bottlenecks that the utility-scale solar market might face in the coming years: labor and tax equity availability, supply chain constraints, increased solar penetration on the grid, and the projected levelized cost of various energy sources. For each year, we cap our forecast by the most limiting factor that results in the lowest level of buildout, and we distribute the final buildout to each state.

12.3. Average system price data and methodology

As of Q1 2014, Wood Mackenzie and SEIA employ a bottom-up methodology based on tracked wholesale pricing of major solar components and data collected from multiple interviews with industry stakeholders. There was a different methodology in place before Q1 2014.

The solar industry often uses the terms "price" and "cost" interchangeably and inconsistently. In the market, price and cost are dependent on perspective. A homeowner's costs are equivalent to an installer's price and so on throughout the value chain. To reduce confusion, we define PV system price from the seller's perspective, which includes the seller's margin.

National average PV system pricing reflects installed prices for any given quarter, rather than quoted prices. Due to the data sources used to obtain system pricing information, these prices are more reflective of turnkey pricing on standard systems for medium and large-sized installation and EPC firms. Starting in Q3 2021, commercial and utility solar average module prices no longer include multicrystalline-silicon due to the diminished demand for this technology. We assume all products are procured and delivered in the same year as the installation for all market segments.

Components in the national cost breakdown categories include:

- **PV modules:** National weighted average delivered pricing for silicon modules.
- **PV inverters:** National average factory-gate pricing with product as specified in the respective market segment.
- **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 electrical and structural balance of system hardware and system commissioning. Excludes any site preparation – those are included under the civil costs.

- **Design & engineering:** Includes all system engineering, design performed by installers / EPC's internal engineering team.
- **Permitting, interconnection & inspection:** Includes all permitting and interconnection application fees.
- **Logistics and miscellaneous:** Includes shipping and ancillary site mobilization costs. Excludes any equipment warehousing costs.
- **Taxes:** Average US state sales tax applied to all cost categories under residential and commercial segments. The utility segment data no longer breaks out taxes as a separate line item as those are incorporated in the equipment category estimates. These changes have been made to the current system prices as well as historical 2023 prices.
- **Customer acquisition / origination:** Includes all sales and marketing expenses agnostic of any lead generation. Indicative of a cash sale with no financing through the installer for the residential segment.
- **Civil:** Includes site setup and preparation including but not limited to clearing, grading fencing, and access roads. Civil costs are accounted only for only in the utility segment.
- **Overhead and margin:** All project-specific overhead including administration, project management, and installer / EPC contingencies and markup.

Residential solar modeling assumptions:

For residential PV, we specifically model a pitched roofed system:

- Starting Q1 2022 residential solar costs are based on an 8kW rack-and-rail pitched-roof system, an increase from the previous 6kW system, to reflect the average system size installed in the country.
- Residential module price reflecting TOPCon PV modules. The average module size used for residential installations was assumed at 405W up from 390W used in 2024.
- Residential system pricing is based on microinverters as the power conversion device.

Significant pricing variation is a fundamental element of the residential PV market. Considerable disparities exist in residential system pricing due to the size of projects, differences in installation companies, project financing and the dynamics of local markets. In terms of installation hardware, three significant variations drive estimated differences:

- Premium PV module-based systems, including high-efficiency modules, can command prices 25% to 35% higher than standard-efficiency crystalline silicon modules.
- Microinverters and DC optimizers can lead to a premium on the overall system cost due to higher hardware costs.
- Structural balance of system requirements, especially in high wind zones or on clay tile roofs, can drive the cost of racking materials and mounting hardware up by 50%. Rail-less racking solutions also carry a significant premium over rail-based systems.

Commercial solar modeling assumptions:

In the commercial sector, system characteristics that drastically affect pricing, among others, include:

- Geographical differences, in particular:
  - Weather-related building codes (e.g., snow and wind loading)
  - Labor pricing regulations (e.g., requirements for union labor or prevailing wage)
  - Site-specific topographical challenges (e.g., soil conditions)
- System type (e.g., rooftop, carport, ground-mount)
- Customer type and electricity tariff structure

As with residential PV systems, we employ a bottom-up cost analysis for commercial PV, specifically modeling ballasted flat-roof systems. Once again, our inputs come from larger EPCs and integrators that likely have lower pricing relative to the industry mean. To ensure our bottom-up model reflects industry trends going forward, we have standardized around the model of a minimalist flat-roof commercial system, with the caveat that commonplace issues such as roof obstructions can significantly affect system costs. Our bottom-up model assumes:

- 250 kW low-slope ("flat") roof system
- 485 W TOPCon modules
- String inverter-based design topology
- Fully ballasted, blended average of aluminum-based and glass-reinforced mounting structure
- Rectangular array on membrane roof

Utility solar modeling assumptions:

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

- 10 MW_{dc} utility system
- High-power class 600 W TOPCon PV modules and central solution inverters. For utility-scale projects, Wood Mackenzie's system costs assume module purchase orders are placed one year prior to commercial operation date (COD). As a result, module prices are reflective of the purchase order (PO) submittal date
- Utility-scale PV modules and inverters reflecting "factory-gate" pricing, with distribution and low volume markups reflected in the supply chain category
- 1.3 DC-to-AC ratio
- Steel-based fixed-tilt system with pile-driven foundations and horizontal single-axis tracking

12.4. Manufacturing production and component pricing

Wood Mackenzie maintains databases of manufacturing facilities for PV components.

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