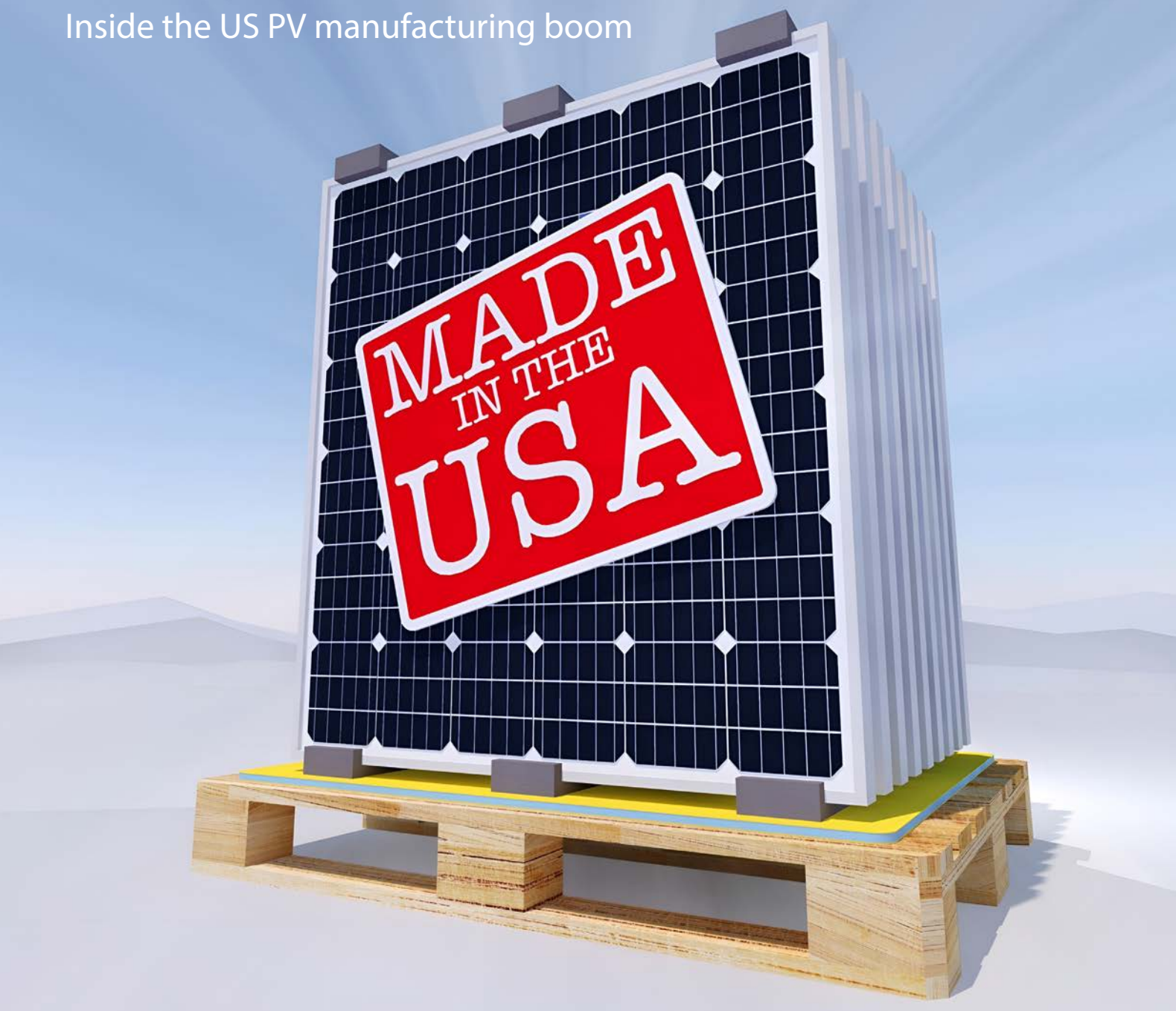
PV Tech Power
by informa

Volume 46 | PV POWER PLANT TECHNOLOGY AND BUSINESS | November 2026 (Q4)

AMERICA'S NEW SOLAR MAKERS

Inside the US PV manufacturing boom



MARKET WATCH
Why c-Si PV manufacturers are turning to space-based solar, p.30



PLANT PERFORMANCE
What 2026's extreme weather tells us about PV performance, p.62

DESIGN & BUILD
Designing PV projects for battery retrofitting, p.70

STORAGE & SMART POWER
US data centres and BESS—not quite a done deal, p.100



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Introduction



This year has seen a rapid acceleration in the growth of America's PV manufacturing industry. The trickle of new module capacity spurred by the Biden administration's 2022 Inflation Reduction Act has become a torrent, and the US now ranks third globally in PV module production. Importantly, 2026 has also seen the beginnings of a serious supply-chain buildout as cell processing begins to catch up with module assembly and attention turns to the higher reaches of the value chain—wafers, ingots and polysilicon.

In this edition of *PV Tech Power*, we feature a special report that takes you behind the scenes of America's burgeoning PV manufacturing sector. On p.15, our colleagues at PV Tech Research explore the key trends shaping the current boom, presenting the latest data on the emerging capacity pipeline and the technology split among the new generation of US manufacturers.

Then on p.20, we speak with some of these players, who discuss their technology choices and where they see their particular niche in the market. Finally, on p.26, Markus Beck, a former official in the Department of Energy's Solar Energy Technology Office, gives his views on how the fledgling US solar manufacturing sector can transition from a gold rush to a resilient homegrown industry. One key takeaway is that while times look good now, without clear demand-side policy and the development of a much deeper domestic PV technology ecosystem, future sustainability is far from a given.

As ever, this edition of the journal is packed with a wealth of other top-notch analytical and technical articles. On p.30 we look at the growing importance of space-based PV as a future demand driver. Space solar has traditionally been a highly specialised niche in the industry, but the large-scale producers of crystalline-silicon PV for terrestrial applications are now eyeing the opportunities presented by a boom in the satellite business.

On p.56, Taylor Geer of VDE Americas explores the ever-thorny issue of PV project modelling. The gap between the modelled and actual performance of PV power plants is a well-known phenomenon; to close it, Geer argues for closer scrutiny of availability, degradation, manufacturing variability and other sources of uncertainty in solar energy models. As he points out, with PV now a cornerstone of the modern energy system, maintaining public faith in its ability to deliver on its promises has never been more important.

Elsewhere in the journal, we explore how PV power plants can be designed to facilitate future retrofitting with battery storage (p.70). On p.77, we examine the phenomenon of 'plug-in' balcony solar in the US, which states are embracing it and some of the technical hurdles involved. And on p.62, Pablo Caballero of Solargis looks at what a summer of soaring temperatures, wildfires and a solar eclipse reveals about PV performance in increasingly extreme conditions.

Finally, in the Storage & Smart Power section, our *Energy-Storage.news* colleagues present a trio of articles, looking at the role of battery storage in supporting the US data centre explosion (p.100), how BESS is helping ease India's grid bottlenecks (p.92) and which countries are leading the way in the geopolitical race for clean energy supremacy (p.104).

As ever, the *PV Tech* and *Energy-Storage.news* teams will be at RE+, where you will be able to find us at booth C4486. We hope to see you there. Thanks for reading.

Ben Willis
Editor
PV Tech Power

Contents









10-14 NEWS

Round-up of the biggest stories in PV from around the world

15-28 COVER STORY

15-18 **US PV capacity buildout: technology, supply chain gaps, policy challenges**
PV Tech Research's Moustafa Ramadan and Joe Hennessy on the latest trends and future challenges in America's solar gold rush

20-24 **Meet the new generation of US PV producers**
The industrialists leading the emerging wave of US solar manufacturing

26-28 **More than module assembly: building a resilient solar ecosystem in the US**
Markus Beck of RCT Solutions on sustaining US PV manufacturing beyond the current boom

30-45 MARKET WATCH

30-33 **From megawatts to gigawatts: how space is pulling silicon PV off the ground**
A satellite boom is creating new opportunities for terrestrial c-Si manufacturers in space

34-38 **India's solar sector: Scaling capacity, strengthening manufacturing**
How infrastructure constraints, financing risks and supply-chain gaps shaping India's solar growth

39-41 **Data centres are Australia's next big solar and storage customer, and the rulebook is still being written**
Can Australia's large data centres become net generators of renewable energy?

42-45 **China's soaring clean power curtailment highlights regulatory gaps**
What is being done to tackle China's escalating solar curtailment problem?

46-55 SYSTEM INTEGRATION

46-52 **Policy upheaval and manufacturing transformation leaves US inverter market at a crossroads**
PV Tech Research's Mollie McCorkindale on the challenges facing the US inverter sector

54-55 **PV plant construction in the cyber age**
How AI-powered robotics is changing the face of PV power plant construction

56-69 PLANT PERFORMANCE

56-60 **Underperformance in fielded solar assets**
Taylor Geer of VDE Americas on how the gap between modelled and fielded PV system performance can be narrowed

62-65 **What summer 2026 tells us about solar generation in a more variable climate**
Pablo Caballero of Solargis discusses how PV asset owners and operators should interpret this year's extreme weather events

66-69 **Lost bypass diodes in PV modules: a hidden fire risk—and how to find it**
Intertek CEA's Jörg Althaus explains what lost bypass diodes are, why they are so difficult to detect and how they can be identified in fielded PV projects

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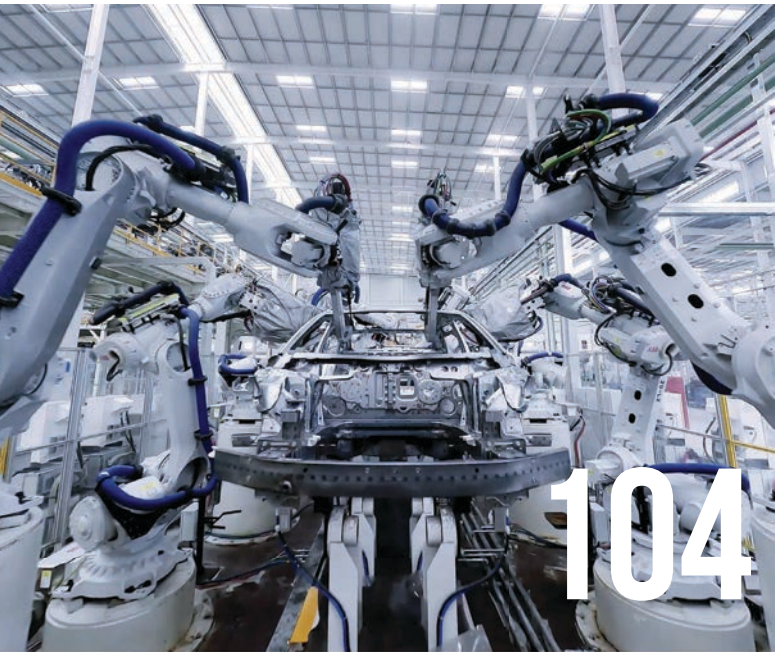
The New-Generation Smart String Grid Forming ESS



Scan for More









70-79 DESIGN & BUILD

70-72 **Avoiding the hidden cost of retrofitting battery storage to solar PV projects**
Stem's Sam Kuhlwein considers how solar developers can best prepare to retrofit batteries

73-76 **From finding viable land to de-risking projects: the evolving role of PV mapping software**
Evan Sarkisian of Glint Solar examines how mapping software is evolving to tackle the challenges of solar and storage site selection

77-79 **Plug-in solar in the US: can policy and safety keep pace with demand?**
Balcony solar in the US, but faces fragmented legislation, uncertain economics and unresolved safety challenges

80-88 FINANCIAL, LEGAL, PROFESSIONAL

80-83 **M&A due diligence for solar and storage in the AI era**
Smart investors are harnessing the power of artificial intelligence to facilitate solar and storage diligence, write Euclid's Jacob Sandry and Rubin Sidhu

84-88 **Hail-hardened modules—promise, limitation and the procurement gap**
FM's Michael Perron examines the PV technology combinations that offer the greatest hail resilience per invested dollar

89-109 STORAGE & SMART POWER

92-97 **Energy storage and smart grids take centre stage in India's renewables shift**
CSTEP's Sarita Vijayvargiya and Shantanu Roy examine the role of battery storage and smart grids in India's new energy landscape

100-102 **Data centre growth, energy storage opportunities and the ratepayer cost debate**
April Bonner looks back at a year in which the US data centre debate took centre stage for society and the energy storage industry alike

104-109 **Who's gaining geopolitical advantage in the energy transition?**
Energy transition expert Chris Nelder profiles the winners and losers in the geopolitical race for clean energy supremacy

REGULARS

03 **Introduction**

91 **News from Energy-Storage.news**

110 **Advertisers' index**

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Tongwei Launches TNC 2.0 FULLX G12R-48 for More Powerful and Adaptable Rooftop Solar

Tongwei Solar has launched TNC 2.0 FULLX G12R-48, a new 48-cell module adopting a mainstream format of 1762*1134*30mm, designed for rooftop applications where available space, installation conditions and aesthetic requirements can vary significantly.

Built on Tongwei's TNC technology platform, TNC 2.0 FULLX G12R-48 combines **high power output, strong energy yield and broad adaptability** in a compact format. The product is available in two design options, **Full Black and Black Frame**, offering customers greater flexibility in both system design and appearance.

The product delivers up to **490 W** with an efficiency of **24.5%**, helping rooftop systems achieve higher installed capacity while maintaining strong energy performance under varying operating conditions.



More Power, More Returns from the Same Rooftop

For rooftop solar, higher module power is only part of the equation. What matters ultimately is how much energy the system can generate from limited roof space and how much value that energy can create.

With up to 490 W of power, TNC 2.0 FULLX G12R-48 provides a 30 W power gain per module compared to conventional TOPCon modules, enabling higher installed capacity on the same roof area and helping make better use of limited rooftop space.

Its power advantage is further supported by the proven energy performance of TNC technology. Field testing showed an average **3.3% gain in per-watt generation** compared with conventional BC modules under the tested conditions (Figure 1). During the low-light periods of early morning and late afternoon, the generation gain reached up to 12.32%, demonstrating stronger energy capture under weak irradiance conditions (Figure 2). This capability is especially valuable in the early morning and late afternoon, when irradiance is low but electricity prices may be higher under time-of-

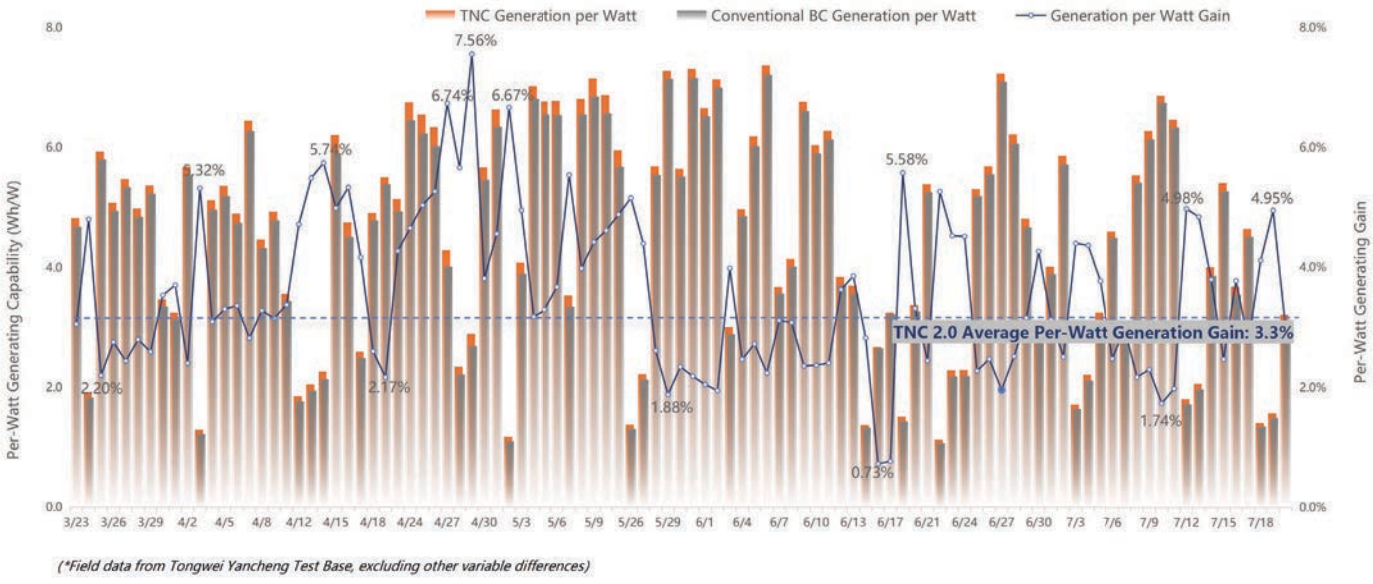
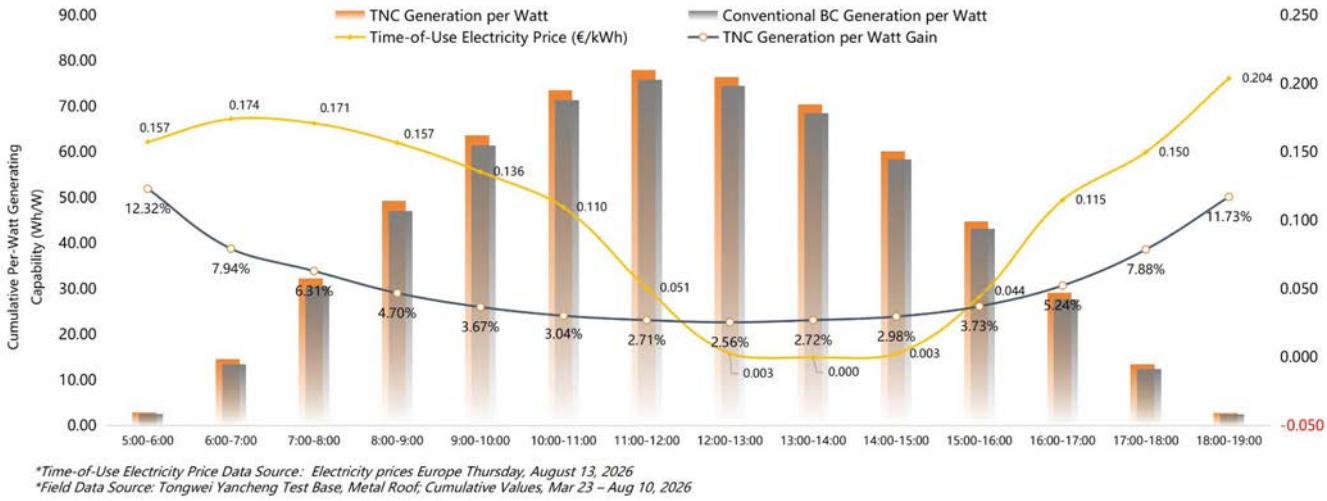


Figure 1: Daily Per-Watt Generation Comparison: TNC vs. Conventional BC Modules (Tongwei Yancheng Test Base)



*Time-of-Use Electricity Price Data Source: Electricity prices Europe Thursday, August 13, 2026
*Field Data Source: Tongwei Yancheng Test Base, Metal Roof; Cumulative Values, Mar 23 – Aug 10, 2026

Figure 2: TNC Generation Gain Peaks During High-Value, Early Morning and Late Afternoon Hours

use tariffs. Generating more power during these high-value periods can help improve the overall value of rooftop solar generation.

The higher energy yield can translate into greater returns over the operating period. In the tested scenario, TNC achieved **447.56 equivalent full-load hours**, compared with 433.27 hours for conventional BC modules, representing approximately **3.3% higher generation capability**. The time-of-use electricity calculation showed an additional revenue of around **€0.03 per day** under the tested conditions.

TNC 2.0 FULLX G12R-48 can also offer a competitive upfront cost by delivering more energy output with lower CAPEX, saving over €400 in initial module investment for a standard 12-module system compared to conventional BC modules.

Adaptability for Real-World Conditions

Not every rooftop can offer the ideal orientation, tilt angle or operating conditions. TNC 2.0 FULLX G12R-48 is built on TNC technology designed to maintain energy performance across a broader range of real-world conditions.

In Germany-based simulations, TNC showed only **0.38% energy loss** related to roof tilt under low-light conditions, compared with **0.96%** for conventional BC modules. This means conventional BC modules were more than **2.5 times more sensitive to tilt** in the tested scenario.

The technology also showed greater adaptability to different roof orientations. At a fixed 40° tilt, TNC recorded approximately **1.02%–1.11%** low-light generation loss across different orientations, compared with **3.53%–3.72%** for conventional BC modules.

This adaptability can help reduce the impact of non-ideal roof layouts, giving installers greater flexibility when designing rooftop systems.

TNC technology also maintains a lower power-loss ratio under different soiling conditions. Compared with conventional BC modules, the reduction in fractional power loss reached **0.40 percentage points under light soiling, 0.73 percentage points under moderate soiling and 0.99 percentage points under heavy soiling**.

This helps reduce the impact of dust accumulation when cleaning cannot be carried out frequently, supporting more stable energy generation under real-world operating conditions.

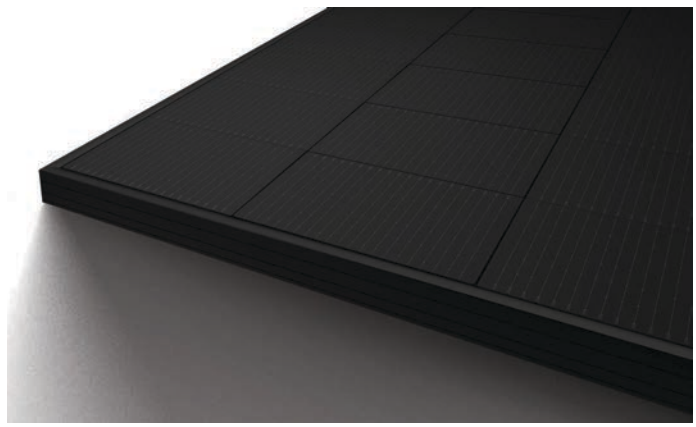
Designed for Modern Aesthetics

Beyond performance adaptability, **TNC 2.0 FULLX G12R-48** is offered in full black option designed for premium rooftop applications. Its clean and uniform look integrates naturally with modern buildings and residential rooftops, where module aesthetics can be an important part of the overall architectural design.

By combining a high-power 48-cell format with the proven energy performance and adaptability of TNC technology, **TNC 2.0 FULLX G12R-48** is designed to meet the realities of modern rooftop solar.

With Full Black and Black Frame options, it gives customers more freedom in system configuration, operating conditions and rooftop aesthetics, while delivering more energy from limited roof space.

TNC 2.0 FULLX G12R-48. More powerful. More adaptable.



AMERICAS

Swift Current sues First Solar over alleged module defects

Independent power producer (IPP) Swift Current Energy has filed a lawsuit against thin-film cadmium telluride (CdTe) solar module manufacturer First Solar in the New York County Supreme Court.

The lawsuit is over alleged module defects purchased between 2021 and 2024, for a supply agreement of over 2.4 million solar panels from First Solar's Series 6 Plus and Series 7, or 1.2GW of power capacity once operational. These solar panels have been installed at three projects owned by the IPP. The companies had signed several supply agreements between 2022 and 2023, with supplies of 1.2GW in January 2022, 2GW in October 2022 and 500MW in November 2023.

One of the projects impacted by the supply agreement is the 800MW 'Double Black Diamond' solar PV project in central Illinois. The modules were installed at the PV project in 2023 and 2024 and according to Swift Current were "immediately plagued by performance issues".

The case is currently ongoing with several exhibits added last week and with both parties scheduled to appear before the court on 16 November 2026.

Swift Current Energy declined to comment on a pending legal matter, while First Solar has not replied, at the time of publishing, to *PV Tech's* request for comment.



Credit: First Solar

First Solar faces legal action over alleged module defects

NextEra Q3 2026 earnings rise 9.7% as shareholders approve Dominion merger

US power utility NextEra Energy recorded a 9.7% increase in its net earnings in Q3 2026, with earnings up 9.5% in the nine months to date this year, according to an earnings call held on 21 October.

In Q3 2026, NextEra Energy reported US$2.592 billion in earnings, compared with US$2.348 billion in Q3 2025. Net income was US$4.775 billion, up from US$2.438 billion in the equivalent period last year. Earnings per share were US$2.28, up from US$1.18 in Q3 2025.

Both income and earnings were up compared to Q2 2026, when the company recorded US$3.144 billion and US$2.407 billion, respectively.

NextEra Energy also said that it is awaiting regulatory approval for its proposed merger with utility Dominion Energy, for which the companies first submitted their application in July. On 3 September, shareholders of NextEra Energy and Dominion Energy approved the merger of the two companies, which will create the largest utility company in the US.

Concord New Energy closes US$400 million financing for Texas solar-plus-storage project

Singapore-based renewable energy developer, owner and operator Concord New Energy (CNE) has closed US$400 million in financing for its US clean energy and digital infrastructure portfolio.

The financing includes US$310 million in debt and letter of credit facilities and US$90 million in preferred equity for a Texas solar-plus-storage project.

The financing supports Project Chisme, comprising 215MW of solar capacity and a 147MW/358 MWh battery energy storage system (BESS). It marks Concord's first utility-scale project financing in the US.

First Citizens Bank, Goldman Sachs Alternatives and Associated Bank led the US$310 million debt and letter of credit financing, while Goldman Sachs Alternatives provided the US$90 million preferred equity investment.

Heliene completes third consecutive annual 45X tax credit transfer

Canada-headquartered module manufacturer Heliene has announced the sale of 2026 Section 45X Advanced Manufacturing Production Tax Credits (PTCs), facilitated by US Bank's community development and infrastructure finance subsidiary, US Bancorp Impact Finance.

The sale, the amount of which was not disclosed, is the third of its kind by Heliene following similar moves in 2024 and 2025.

Despite the passage of the One Big, Beautiful Bill Act (OBBA) by the Trump administration in 2025, the US clean energy sector has seen US$19.9 billion in tax credit sales in Q2 2026.

Last month, Heliene launched a new residential module, the 108HC All-Black, comprising US-made polysilicon, ingots, wafers and solar cells. The modules were subject to a purchase agreement with Sunrun that coincided with the module's market launch.

Toyo expands Texas solar module manufacturing facility to 2GW

Japanese solar manufacturing company Toyo has held a ribbon-cutting ceremony to mark the expansion of its solar module manufacturing plant in Humble, Texas, which will increase the facility's nameplate capacity to 2GW, the company says.

Toyo announced plans to add 1.5GW of heterojunction (HJT) cell manufacturing capacity to the facility in June 2026, and this week confirmed it expects to complete construction of the cell facility in the first quarter of 2028.

Over the summer, the company agreed to sell over 4.5 million shares at a total value of US$50 million to finance the expansion of its HJT cell production capability, amid overall company revenue rises between H2 2024 to end of 2025.



Credit: Toyo

Toyo has completed the expansion of its Texas module manufacturing facility

ASIA

China proposes export controls on polysilicon, wafers and other PV technologies

China's Ministry of Commerce (MOFCOM) is consulting on proposals to introduce export controls on key PV components, including polysilicon, wafers and cells.

The ministry issued an announcement on 16 October seeking public comments on revisions to the Catalogue of Technologies Prohibited or Restricted from Export and the introduction of temporary pre-export registration requirements for the relevant technologies.

The proposed update covers 40 technologies spanning three sectors: artificial intelligence, biomedicine and photovoltaics. Under the PV category, 12 new technologies related to polysilicon, wafer and solar cell manufacturing have been proposed for inclusion. The scope will also cover key core equipment that embodies these technologies, strengthening export oversight over critical PV technologies.

According to the announcement, PV technologies proposed for control under this revision fall into two categories: prohibited and restricted. The prohibited list covers polysilicon, wafer and solar cell production technologies.

The prohibited polysilicon production technologies include the cold hydrogenation fluidised-bed process with a single-line trichlorosilane capacity of at least 250,000 tonnes per year, the silane fluidised-bed process with a single-line capacity of at least 20,000 tonnes per year and their associated equipment manufacturing technologies.



Credit: Longi

Chinese authorities are seeking to place export restrictions on certain key PV technologies

India curtails 96.9GW of solar PV in September

Solar PV curtailment in India reached 96.9GW in September, according to research and analysis company JMK.

While curtailment in September this year was lower than the previous year's figure, down 24%, this follows a period between May and August in which curtailment was four times higher compared to the same period in 2025.

In September 2026, the equivalent of 1.28% (118.6 GW) of total renewable energy was curtailed, with solar accounting for 96.9 GW of curtailment and the remainder mostly wind generation. JMK suggests that the reasons for renewable curtailment include demand-generation mismatches, transmission constraints and a lack of storage and grid flexibility.

Seasonal trends can also affect curtailment figures. JMK considers the period from April to July to be the peak window of renewable generation in India, while autumn can be characterised by high renewable output and moderate electricity demand, leading to higher curtailment.

Shanghai Customs uncovers 16 cases of PV products suspected of infringing on intellectual property

On 10 October 2026, Shanghai Customs released data showing that from January to September 2026, frontline port offices under its authority, including Waigaoqiao Port Customs and Yangshan Customs, handled 16 cases involving solar PV products suspected of infringing on intellectual property (IP), with a total value of more than RMB5 million (US$750,000).

These products were found at Chinese ports awaiting export overseas, suggesting some are looking to exploit China's strong solar manufacturing sector—Chinese manufacturers account for more than 80% of global manufacturing capacity across the solar supply chain—and sell counterfeit products overseas.

During IP-rights enforcement efforts, several PV module manufacturers have assisted customs in intercepting modules shipped through unauthorised channels. JinkoSolar noted it had recently uncovered multiple infringement incidents in overseas markets, where counterfeit products were sold.

"We closely monitor key commodities, use intelligent trademark-recognition tools, and verify authenticity from multiple dimensions including packaging workmanship, anti-counterfeit labels and manufacturing details to cut off the export channels for infringing goods," said Zhao Fangxiao, chief of the Fourth Inspection Section at Waigaoqiao Port Customs.

Sungrow patches cloud vulnerability affecting solar inverters

Chinese solar PV inverter and energy storage manufacturer Sungrow has patched a vulnerability in its iSolarCloud platform that allowed access to platform accounts without the required authentication, according to the company.

The vulnerability was made public earlier this month by German cybersecurity firm Jakkaru, which said on LinkedIn that it had been able to gain access to "all Sungrow solar systems installed worldwide", accounting for gigawatts of power generation capacity. Jakkaru's Marlon Starkloff noted that on the Sungrow platform, "normal user accounts and administrative user accounts share the same management platform", which means that accessing a normal user account could leave an administrative account exposed and create a "dangerous scenario".

Starkloff explained in a blog post that the Sungrow platform has at least eight types of login process and that by setting the process to number five, "we were immediately logged in".

"The password field is ignored," wrote Starkloff. "This was a critical finding. What made it worse was the fact that no notification was sent to the user. No login notification by email or similar.

An independent security researcher working with Jakkaru informed Sungrow of the vulnerability on 22 August. Sungrow reproduced the attack and deployed an emergency patch across all iSolarCloud levels on 25 August, resolving the underlying issue the same day.

EUROPE

Recurrent Energy begins commercial operations at 200MW Villameca solar project in Spain

Canadian Solar's owner-operator subsidiary Recurrent Energy has announced the start of commercial operations at the 200MWp Villameca Project in Castilla y León, Spain.

Recurrent Energy said that it expects to have 1GW of operational solar capacity in Spain by the end of this year, alongside the company's 426MWp Rey Solar Project in Andalucía and the 315MWp Tordesillas Project in Castilla y León.

Dylan Marx, CEO of Recurrent Energy, said: "We are particularly proud of this project's impact and the high level of social and biodiversity commitments achieved throughout its development."

The Villameca Project is expected to be hybridised with the addition of battery energy storage systems (BESS), the company says, an addition that is more usually part of a large-scale facility's design.



Credit: Recurrent Energy

Recurrent Energy is aiming for 1GW of operational PV in Spain by the end of 2026

German industry groups oppose proposed solar prosumer grid surcharge

An alliance of 11 German associations representing the energy, housing, real estate and skilled trades sectors has urged the Federal Network Agency to scrap a proposed grid surcharge on solar prosumers, warning it could undermine rooftop solar economics, deter investment and slow Germany's solar expansion.

A legal opinion commissioned by BSW-Solar, the German solar association, has also questioned the surcharge's legality, citing potential conflicts with EU law and constitutional protections for existing solar installations.

The proposed surcharge forms part of a wider debate over electricity grid charges, including whether households that generate and consume their own solar power should contribute more towards grid costs, irrespective of the grid capacity they actually use.

The associations argue that such a system could increase costs for solar households and weaken the financial case for installing new systems. The impact could be compounded by planned reductions in solar power subsidies by the German federal government.

HoloSolis appoints former rail executive Henri Poupart-Lafarge as CEO

French solar manufacturer HoloSolis has appointed former rail executive Henri Poupart-Lafarge as its new CEO.

Poupart-Lafarge replaces former CEO Bertrand Lecacheux, who stepped down on 10 September to take the position of deputy managing director of business at French engineering company CAP INGELEC. Lecacheux spoke on a panel hosted by PV Tech at least year's Intersolar Europe event, and Holosolis said at the time of his departure that it remains "fully focused" on its project to rebuild solar manufacturing in Europe.

"All the major economic powers, such as China, the US and India, have built up a sector in this strategic field to ensure their energy sovereignty," said Poupart-Lafarge. "This project is taking shape at a time when Europe is becoming acutely aware of how far behind it is and of the urgency to act on solar energy issues, so I am excited to be able to play my part in this endeavour."

Prior to his appointment at HoloSolis, Poupart-Lafarge worked at French rail transport systems manufacturer Alstom in a number of roles, including a decade as CEO.

Pexapark: September 2026 PPA prices rise 5% across Europe

The prices of European renewable energy power purchase agreements (PPAs) rose by 5% in September, according to monthly figures published by Pexapark.

PPA prices rose in most European markets, most notably in the UK, which saw the strongest monthly increase of 10.9%. Spain and Portugal experienced declines in prices, with average prices falling 3.5% and 1.4% respectively.

The Swiss price intelligence platform company's September analysis notes that its re-calibration of the Danish PPA fair values contributed to some of the statistical changes. In Denmark, the ten-year annual baseload fair values, starting in 2028, were lowered by around €5/MWh (US$5.6/MWh) as "offtakers widened the risk discounts embedded in their pricing."

The composite PPA price figures have seen a rebound from this summer, reaching an average price of €48.34/MWh (US$54.12/MWh) in September, compared to €46.02/MWh (US$53.1/MWh) in August.

ESMC calls for EU policy support to 'rebuild the full PV value chain'

The European Solar Manufacturing Council (ESMC) has called on the European Parliament, European Council and individual member states to rebuild the European PV industry across its entire value chain.

The council has argued in favour of this in an open letter, sent to the European Parliament's Industry, Research and Energy (ITRE), Internal Market and Consumer Protection (IMCO) and International Trade (INTA) committees. The ESMC quotes figures from the Fraunhofer Institute for Solar Energy Systems (ISE), saying: "A European solar PV manufacturing value chain at 30GW per year would create around 80,000 jobs and add €4 billion (US$4.48 billion) to EU GDP."

The position paper and joint letter, signed by European manufacturers from eight member states, Switzerland and the UK, set out three demands: a strict 'Made in Europe' definition for the EU's Industrial Accelerator Act (IAA), adequate market protections and investment and operating support to scale the value chain and attractive private investment.

The ESMC calls for the EU's IAA to include a strict definition of the 'Made in Europe' moniker that would cover the entire solar hardware value chain, to be established in the next five years. This would include European-made production equipment used to manufacture PV components. The marking would be an opt-in for companies of EU origin rather than an automatic extension for free-trade-agreement partners such as Switzerland.

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IDOM to undertake site studies and design for 500MW Shanxi solar project in Oman

Chinese construction company the Shanxi Installation Group has selected Spanish engineering consultancy IDOM to design its 500MW Al Kamil I Solar Project in Oman.

IDOM will define the initial site studies and provide detailed designs of the proposed solar plant, which is part of Oman's strategy to increase the share of renewable energy in its power generation mix and advance its long-term sustainability objectives.

The company said that it has provided engineering services for several Spanish PV plants with a total capacity of over 250MW, including feasibility studies; engineering, technical and financial due diligence; and permitting management.

The Shanxi collaboration will also not be IDOM's first work outside of Spain; construction company Engie Energía Perú contracted the firm to provide engineering services during the planning, design and construction phases of its 40MW Intipampa PV power plant in Moquegua, Peru.

Oman has seen a surge in gigawatt-scale solar procurement in the last two years, most notably the commissioning this year of the Manah Phase I & II solar projects, with a combined capacity of 1GW.



Credit: IDOM

IDOM is to undertake design work on a 500MW PV project in Oman for Chinese contractor Shanxi Installation Group

EBRD provides US$265 million loan for 1.2GW solar-plus-storage project in Egypt

The European Bank for Reconstruction and Development (EBRD) has announced a US$265 million loan for a new 1.2GW solar PV plant, to be co-located with a 600MWh battery energy storage system (BESS), in Minya, Egypt.

The EBRD loan will be made to Nefer Menya for Renewable Energy, a special purpose vehicle (SPV) created by African independent power producer (IPP) Infinity Power and Egypt-headquartered Hassan Allam Utilities (HAU) Energy.

The facility will be the largest solar power plant in Africa, and electricity generated at the Minya facility will be sold under a 25-year power purchase agreement (PPA) to the Egyptian Electricity Transmission Company.

The project is one of several to combine solar generation with on-site battery storage in Egypt, and joins projects owned by Norwegian IPP Scatec and UAE-based AMEA Power.

Axian, Africa GreenCo ink 240MW PV PPA in Zambia

Pan-African renewables developer Axian Energy has signed a power purchase agreement (PPA) with energy aggregator and trader Africa GreenCo in Zambia.

The offtake agreement will cover the 240MW Kudu solar PV plant, which has been financially backed by African bank Standard Bank and its Zambia subsidiary, Stanbic Bank Zambia, as the project moves towards financial close and the construction phase.

Axian Energy entered into Zambia's energy market last year with the acquisition of a 85.6% stake in a 54.3MWp PV project. Located in the southern Lusaka Province in the Kafue District, the Bangweulu Solar plant was the first utility-scale solar PV project to begin commercial operations in Zambia and was developed by French independent power producer (IPP) Neoen.

Saudi 250MW solar PV site is base for endangered species breeding programme

The 505-hectare site of operational solar park in Saudi Arabia is to host a breeding programme for an endangered species.

The site of the 250MW solar park in the Prince Mohammed bin Salman Royal Reserve is considered to be an environment in which sand gazelles can establish a viable herd.

The solar PV facility is built and managed by the Amaala Sustainable Company for Energy (ASCE), a joint venture of the EDF Group, Masdar and SUEZ and Korea East-West Power (EWP).

A seven-month proof-of-concept was launched in October 2025 involving several species, and sand gazelles were selected for their ecological importance and suitability for the site's environment. Thirty-eight sand gazelles were introduced into the solar plant in May 2026 and are expected to produce offspring by December this year.

US PV capacity buildout: technology, supply chain gaps, policy challenges

Manufacturing | The US is witnessing an explosion in domestic PV manufacturing activity as policy carrots and sticks drive a huge capacity buildout. Moustafa Ramadan and Joe Hennessy of PV Tech Research look at the latest trends and future challenges in America's solar gold rush

The United States solar manufacturing sector stands at a critical juncture. After years of import dependency, a wave of domestic capacity announcements has reshaped the landscape, driven by federal incentives and trade policy. Yet beneath the headline figures lies a more complex reality: a supply chain being built downstream-first, technology fragmentation driven by intellectual property concerns and a policy environment that supports production but leaves demand exposed.

Understanding where US solar manufacturing capacity is headed by 2030 requires looking beyond announced gigawatts to examine what is actually under construction, which technologies are being deployed and whether the policy framework can sustain the market these facilities are being built to serve.



Credit: Qcells

Qcells is a notable player in the new generation of US-based PV manufacturers, with a newly completed integrated plant in Georgia

The current state: downstream saturation, upstream constraints

US module manufacturing capacity has expanded dramatically, reaching over 85GW in total nameplate capacity (including thin film) and 66GW on a crystalline silicon basis as of 2026, with production at approximately 46GW. This represents nearly an 800% increase since the Inflation Reduction Act's (IRA) manufacturing tax credits were implemented in August 2022. The country now ranks as the third-largest module producer globally, surpassing the 50GW target the Solar Energy Industries Association (SEIA) set for 2030—four years ahead of schedule.

However, this rapid module capacity growth masks significant imbalances further up the value chain. Current US polysilicon capacity stands at 35GW, but only 12GW is allocated to PV production, with the remainder serving semiconductor-grade applications. This shared-capacity dynamic creates a structural constraint: any increase in semiconductor demand would further squeeze PV allocation and impose a harder ceiling on domestic solar supply-chain integration.

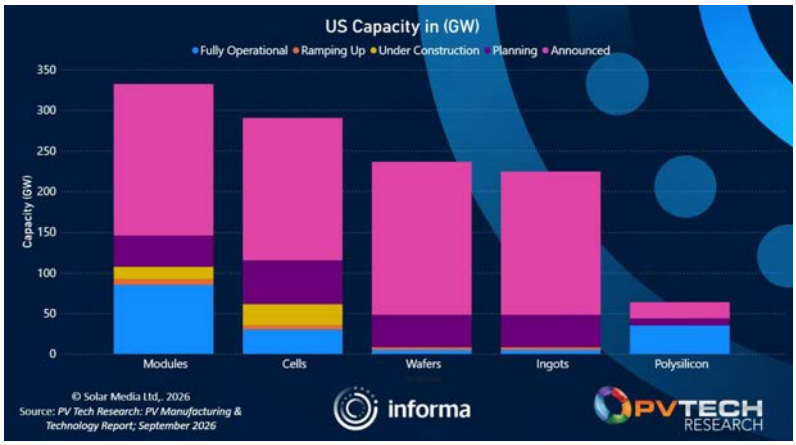
Wafer production represents the most acute bottleneck. Solar-dedicated wafer capacity totals just 5GW against 3GW of production—a 64% utilisation rate that reflects facilities still ramping up. While utilisation is expected to exceed 70% from 2027 onward, wafer capacity remains the smallest segment by volume and the most directly exposed to upstream polysilicon constraints.

Cell manufacturing shows the clearest capacity-production split. Including First Solar's thin-film operations, total cell capacity reaches 30GW compared with 21GW of production—a 70% utilisation rate reflecting mature cadmium telluride-driven operations. Strip out thin film, and crystalline silicon (c-Si) cell capacity falls to 10GW with only 5GW of production, roughly 50% utilisation. This is the segment where the announced construction pipeline is most aggressive relative to existing capacity.

The technology-specific data reveals the depth of the cell-module mismatch. Passivated contact and rear cell (PERC) module capacity stands at 27GW year-end capacity against 15GW yearly production, while PERC cell capacity is just 7.5GW year-end against 4.6GW yearly production. Domestic PERC cell capacity covers only about 30% of domestic PERC module capacity, meaning well over half of the silicon going into US-assembled PERC modules must originate as imported cells. Heterojunction (HJT) shows an almost identical pattern at a smaller scale: module year-end capacity of 7GW versus 1.3GW of yearly production, and cell year-end capacity of 2.3GW versus 1GW of production. HJT cell capacity covers roughly 30% of HJT module capacity—essentially the same shortfall as PERC.

The construction pipeline

PV Tech Research's US Domestic Solar Manufacturing Tracker currently records 31GW of cell manufacturing capacity under construction or ramping up—by far the largest single buildout of any segment (Figure 1). Module capacity under construc-



Source: PV Tech Research

Figure 1. The current US PV manufacturing pipeline by supply chain segment and stage

tion or ramping up adds a further 22GW. Behind both, wafer and ingot capacity have no capacity under construction but have just 3.3GW currently ramping up. The imbalance is stark: for every dollar of committed cell capacity, comparatively little capital flows to the wafer-to-polysilicon stages that must scale in parallel if that cell capacity is to rely on domestic rather than imported inputs.

The timing of this buildout is critical. The bulk of construction is concentrated in 2026 and 2027, and that timing is not incidental. Section 232's polysilicon investigation, layered on top of existing tariff and Foreign Entity of Concern (FEOC) compliance regimes, has pushed manufacturers across the chain to bring capacity onshore ahead of policy deadlines rather than in response to demand signals alone. This creates genuine risk that the current wave of announcements reflects a rush to be compliant and eligible for support under the 45X, 45Y and 48E credit structures, rather than a durable, demand-matched expansion.

A fragmented technology picture

The technology split within the pipeline reveals a market that is not converging on a single dominant crystalline technology, as most of the rest of the world has (Figure 2). At the cell stage, tunnel oxide passivated contact (TOPCon) leads newly announced capacity with 10.1GW, HJT at 18GW, PERC at 13.8GW and the remainder distributed across other technologies, including perovskite. At the module stage, HJT dominates announced capacity at 21GW, significantly outpacing TOPCon at 5GW and PERC at 4GW.

This divergence is worth examining closely. TOPCon remains a technology that manufacturers are willing to build new cell capacity around, likely because it is the most commercially proven route and offers a clear efficiency advantage over PERC. However, when it comes to new module capacity, HJT is where the announced pipeline is concentrated—a signal that a meaningful share of US manufacturers are positioning module assembly around a technology they view as further removed from the patent risk building up around the TOPCon-to-back-contact transition, even while a separate cohort continues building TOPCon cell capacity in parallel. An argument made at a CellTech USA event by HJT manufacturers is that the US is a premium market and thus should be getting the most efficient technology.

This technology divergence is not simply a transitional phase. It reflects a structural feature of the US solar manufacturing landscape, one shaped as much by legal strategy as by technical or economic logic. The result is a market hedging across multiple technology pathways simultane-

US policy, workforce challenges and space-based solar lead PV CellTech USA discussions

Jonathan Touriño Jacobo reports from this year's PV CellTech USA conference, where policy and labour shortages dominated discussions

PV Tech's annual PV CellTech USA conference is an ideal opportunity to take the temperature of America's PV manufacturing industry. Given the huge level of activity seen this year, the 2026 event, hosted in early October, was especially well-timed.

PV industry experts, from leading manufacturers to legal experts, gathered in San Francisco to discuss the current and future landscape of US domestic solar manufacturing. Policy, particularly the Section 232 tariffs on polysilicon and the future of tax credits, featured prominently in discussions. Other noteworthy takeaways this year were the workforce challenges facing US manufacturing and the industry's next frontier: space-based solar power.

Policy at the forefront: Section 232, 45X

Undoubtedly, policy was a key topic of conversation at the conference, especially Section 232 and the possibility of extending tax credits for manufacturing through Section 45X and the Investment Tax Credit (ITC).

Regarding Section 232, there are still some uncertainties regarding the state of affairs post-4 December 2026 when it will kick in, but the Trump administration has already taken steps to minimise opportunities to exploit loopholes in the legislation, such as anti-stockpiling measures imposed in September.

"The current administration will aim to make examples of people who try to avoid or circumvent the restrictions through very strict enforcement," said Moustafa Ramadan, head of PV Tech Research. We heard that attempts to bring in semi-finished components, such as blue wafers, would not succeed as the administration is closely monitoring the entire solar value chain. There are already mentions of dozens of importers who have been barred from importing solar products before 4 December.

However, the tariffs are not fully set in stone and will likely need to be modified in the coming months, especially to allow time for solar manufacturers to onshore domestic solar cell manufacturing and further upstream in the supply chain.

On the extension of tax credits for manufacturing, the consensus was this would be desirable, with optimism that there is room to revisit the expiration date. On top of that, and certainly tied to Section 232, is the need to ensure that other parts of the supply chain receive sufficient financial support to build domestic manufacturing capacity.

Until now, the majority of the domestic manufacturing has been towards modules and cells, but more could be done to help other parts of the supply chain, including other components that are still scarce in the US, such as silver paste, encapsulants and glass, and to ensure manufacturers receive the financial support necessary to build manufacturing capacity.

Maintaining and training skilled workers

Another much-discussed issue among PV manufacturers across the value chain was the difficulty of hiring and retaining skilled workers.

The lack of current know-how for PV manufacturing, especially solar cells, is making it much harder for manufacturers to find and keep skilled workers. Considering that the US only began producing solar cells again in 2024 after a five-year hiatus, the pool of workers with the necessary know-how is limited.

However, manufacturing hubs such as Texas, where many companies have built or are building PV manufacturing facilities, could help create an ecosystem with a pool of workers trained or experienced in solar manufacturing.

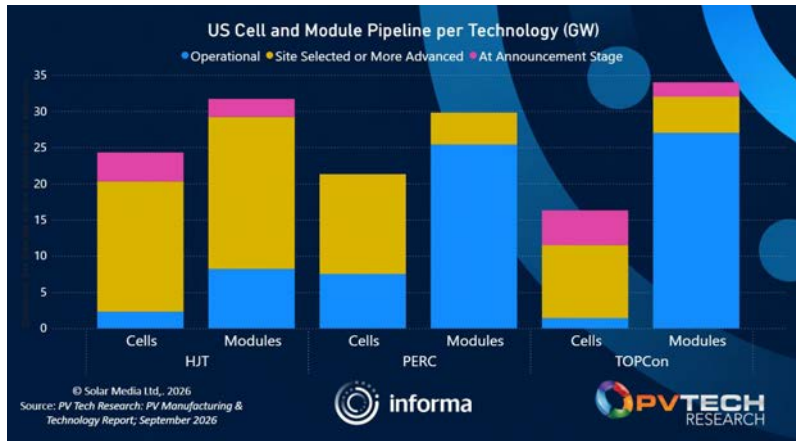
ously, creating a cell-to-module capacity gap that appears set to persist across all three technologies through 2030, regardless of which one ultimately prevails.

HJT is emerging as the n-type technology of choice as US manufacturers seek to minimise intellectual property-related risks. TOPCon's compatibility with existing PERC production lines makes it attractive from a capital efficiency standpoint, but the patent landscape surrounding TOPCon and its evolution toward back-contact architectures has created uncertainty that HJT, with its distinct manufacturing process and IP structure, partially sidesteps.

The 2030 outlook

By 2030, PV Tech Research expects the US to have built out most of its currently announced capacity, and for the gap between module and cell capacity to have substantially closed. That is a meaningful shift from today's market, where cell capacity accounts for 33% of module capacity (including thin film). If the pipeline converts as expected, the module-cell mismatch that currently forces import dependency at the cell stage should no longer be the binding constraint it is today.

The situation remains less definitive further up the supply chain. US polysilicon capacity allocated to PV is projected to reach approximately 40GW by 2030. Ingot and wafer capacity are expected to add an extra 43GW each, a substantial increase from the current 5GW, though most of that capacity will sit with one or two integrated manufacturers. It remains to be seen how much of that capacity will be available to the rest of the market.



Source: PV Tech Research

Figure 2. The technology picture is fragemented, with TOPCon leading in module assembly but HJT building a pipeline of cells and modules concurrently

The most significant structural weakness in the US value chain expected to emerge by 2030 is the constraint of domestically manufactured polysilicon that frequently lacks domestic pulling and wafering options. The resulting supply chain by 2030 will still be downstream-concentrated: the bulk of manufacturing investment and capacity growth continues to be concentrated in cells and modules, while polysilicon-to-wafer capacity remains the stage most likely to require imports to complete the chain.

It is also worth noting that the core value chain—polysilicon through to modules—is not the entire ecosystem. Equipment, materials and the broader supporting infrastructure remain comparatively underbuilt relative to the core manufacturing stages, and represent a second, less visible gap alongside the wafer shortfall.

Three factors that will determine conversion rates

Three factors will determine how much

Marvin Yang, business development manager at Texas-based manufacturer Imperial Star, spoke about the challenges of building a robust domestic supply chain and said that "developing people early" is a priority to ensure a skilled workforce.

"We plan for expansion by developing people early," he told *PV Tech*, speaking about the company's module manufacturing plant in Tomball, Texas. "During Phase 1 in Tomball, we hired and trained 20% additional staff in key engineering, quality and operations roles. They gain hands-on experience in the existing factory so they're ready to lead as we bring Phases 2 and 3 into production. That gives us an experienced team in place before the new lines start and ensures a smooth ramp-up to 5GW in 2027."

Space-based solar: from fiction to reality?

The final key takeaway from this year's PV CellTech USA relates to space solar. This looks set to become a new frontier for the PV industry as a boom in the satellite business creates new market opportunities for solar cell technology.

Whereas last year, all the attention was on perovskite, this year, space-based solar was a recurring theme throughout the conference, with the second day featuring a session on how space solar is driving the next generation of PV innovation.

Even though gallium arsenide solar cells have been the predominant space PV technology until recently, silicon cells are making a comeback, with PERC, TOPCon, and HJT favoured due to limited gallium availability and insufficient capacity to supply the market. Among these, p-type heterojunction (P-HJT) seems to have an advantage over others, as recently demonstrated by the first in-orbit test of P-HJT modules by Chinese PV manufacturer JA, which was successfully launched on a Chinese satellite.



PV CellTech USA 2026 was a chance to take stock of the US PV industry's successes and challenges

Perovskite solar cells could even work well in space, since the vacuum there avoids the durability problems they face on Earth. Space missions also only need solar panels to last under a decade, far less than the 25-30 years required for utility-scale solar projects.

Despite increased interest in space solar applications, with talk of hyperscalers exploring the possibility of building data centres in space, the market is still expected to remain quite niche and much smaller than the hundreds of gigawatts installed on Earth every year. The forecasted demand for solar cells in space in the coming years would be around 100MW, falling well short of the gigawatt scale.

of the announced pipeline converts into operational capacity by the end of the decade. First, whether polysilicon expansion, currently lagging in both PV availability and construction timing, can accelerate enough to feed the wafer and cell capacity being built ahead of it. Second, whether the crystalline silicon cell buildout, which accounts for the largest share of capacity currently under construction, avoids the kind of overbuild that outpaces both polysilicon supply and end-market demand. Third, whether the policy environment that triggered this wave of investment—Section 232, FEOC restrictions and the tax credit framework—remains stable enough that projects greenlit in 2025 and 2026 remain economically viable when they reach commissioning.

The data reveals a supply chain being built out up the value chain: downstream capacity racing ahead while upstream bottlenecks persist, construction timelines clustering around policy deadlines rather than demand cycles and headline announcements masking an imbalance that threatens to leave cell and module capacity starved of feedstock, markets, or both.

The policy environment: support for production, exposure on demand

The clearest recent example of policy intervention came in August 2026, when Minimum Import Pricing (MIP) under Section 232 was announced—a price-floor mechanism extending across the entire solar value chain. Effective from 4 December 2026, the following minimum import prices apply: US$21 per kilogram for polysilicon, US$100 per kilogram for polysilicon ingots and wafers, US$0.22 per watt for solar cells and US$0.38 per watt for solar modules. Additionally, a 15% ad valorem tariff applies to polysilicon ingots and derivatives.

MIPs are an effective short-term correction, giving domestic manufacturers room to compete against import pricing that would otherwise undercut the buildout. But a price floor is a short-term tool, not a long-term industrial policy, and it does nothing on its own to support the deployment side of the market.

The survival of the 45X manufacturing credit is encouraging because it is durable and directly supports the manufacturing base. The Section 45X Advanced Manufacturing Production Credit, established under the Inflation Reduction Act, has been instrumental in driving the manufacturing capacity expansion documented throughout this analysis. Since the tax credit was enacted in 2022, the US has risen from 14th to third globally in solar panel manufacturing capacity.

However, the One Big Beautiful Bill Act (OBBBA) enacted in 2025 significantly tightened timelines for solar projects. Under the new requirements, any solar project that begins construction after 4 July 2026, must be placed in service by 31 December 2027. The OBBBA also introduced complex Prohibited Foreign Entity requirements that taxpayers must comply with beginning in 2026 for the Investment Tax Credit (ITC), Production Tax Credit (PTC) and manufacturing tax credit.

What remains missing is an equivalent downstream policy to govern and sustain deployment. The foundation has been laid for a domestic manufacturing base capable of producing every major component of the solar supply chain. Whether it supports a thriving domestic industry or becomes stranded capacity will depend on sustaining robust end-market demand for modules in the coming years, particularly as existing tax credits phase out and the industry transitions from policy-driven growth to market-driven momentum.

The demand-side gap: manufacturing without markets

What could derail the 2030 forecast is less a manufacturing question than a policy one: a MIP regime and a 45X credit that support production but not deployment leave the demand side of the market exposed. It is ultimately demand, not announced capacity, that determines whether the projections in this analysis are realised or not.

The accelerated phase-out of the ITC for solar projects started after 2027 under OBBBA, combined with increased Domestic Content Bonus requirements, creates a compressed timeline for project development that may not align with the manufacturing capacity coming online. While the bill maintains the Section 45X credit for solar manufacturers, the conflicting signals—supporting manufacturing while constraining project deployment timelines—create uncertainty about whether sufficient domestic demand will materialise to absorb the production capacity being built.

Industry experts have noted that these conflicting political decisions are causing collateral damage to the solar industry. The US solar manufacturing and supply chain saw major gains in 2025, but faces an uncertain market heading into 2026 and beyond. The challenge is not simply building factories; it is ensuring those factories have customers.

A manufacturing base in search of market certainty

The US solar manufacturing sector has achieved remarkable capacity growth in a compressed timeframe, driven by federal incentives and trade policy that have successfully catalysed investment across the value chain. By 2030, the country is positioned to have substantially closed the cell-module capacity gap that has defined the current market, with meaningful expansion in polysilicon and wafer capacity as well, though upstream constraints will persist.

However, the success of this buildout ultimately depends on factors beyond manufacturing capacity itself. The technology fragmentation across PERC, TOPCon, and HJT reflects a market hedging against intellectual property risk rather than converging on technical or economic optima. The concentration of construction timelines in 2026-2027 reflects policy deadline-driven investment rather than demand-matched expansion. And most critically, the policy framework that has successfully supported manufacturing investment has not been matched by equivalent long-term support for deployment.

The resulting supply chain by 2030 will be downstream-concentrated, with cells and modules representing the bulk of capacity growth while polysilicon and especially wafer capacity remain the stages most likely to require imports. Equipment, materials and supporting infrastructure remain comparatively underbuilt. And the entire ecosystem faces the fundamental question of whether domestic demand will be sufficient to absorb the production capacity being created.

The foundation has been laid. Whether it supports a thriving domestic industry or becomes stranded capacity will depend on policy choices made in the coming years—not about manufacturing tax credits or import price floors, but about sustaining the deployment-side demand that gives those manufacturing investments a market to serve. Without long-term downstream policy to maintain demand for the PV hardware being manufactured on US soil, the impressive capacity buildout documented in this analysis risks becoming a supply chain in search of customers. ■

Turn to p.20 to meet some of the new generation of US PV producers

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Meet the new generation of US PV producers

Manufacturing | Seven leading figures in the emerging wave of US solar technology manufacturers share their strategies, technology choices and views on building a domestic supply chain amid shifting policy landscapes, geopolitical tensions and surging power demand

'Workhorse' PERC technology to drive Suniva's scaling up of US solar cell production

PERC technology still has key role to play in US cell manufacturing, says Suniva's Matt Card



Despite technical advancements through tunnel oxide passivated contact (TOPCon) and heterojunction technologies (HJT), passivated emitter rear cell (PERC) has the potential to be a "workhorse" in the US cell manufacturing space, where simply producing cells at volume is the priority.

This is according to Matt Card, president and COO of US cell manufacturing veteran Suniva. The company's plans took a significant step forward in early September, when it announced US$835 million of new capital to support the development of a new cell manufacturing plant in South Carolina that will push its cumulative annual manufacturing capacity to 5.5GW.

"Suniva will continue to produce PERC cells," Card says. "What this announcement validates is that PERC remains a workhorse product, particularly in the US market."

PERC has been a key component of the company's return to cell manufacturing, which began with the relaunch of its manufacturing facility in Georgia in 2024. Card says this period was a "highly dynamic regulatory environment for the use of TOPCon", which improved the business case for other types of cell technology.

"PERC was tried and true," he explains, pointing to the plethora of legal disputes that have embroiled the world's leading TOPCon manufacturers in recent months. "What we did not want to do was build a facility and then immediately get enjoined by someone saying 'you have a patent violation here, you have a patent violation there.'"

Card says there were "three pillars" behind the company's decision to use PERC. The first was the legal landscape in the US. The second pertains to technology, as Card argues that "TOPCon is a much more volatile substance to build than PERC".

The third pillar is the economic reality of producing PERC cells versus other cells. "The reality is that, assuming PERC looks good and TOPCon looks good, TOPCon has multiple additional manufacturing steps that PERC does not have," explains Card. "It physically takes several [more] hours to make a single TOPCon cell than a single PERC cell. You can simply create more physical units of solar cells on PERC than you can on TOPCon."

This difference in scale is significant in the US where there is much more module deployment and module manufacturing capacity in operation than cell manufacturing. "There had been such a headstart in deployment and module manufacturing, and a lack in cell manufacturing, [and] what I think we correctly ascertained was that the challenge in the US, in the intermediate term—meaning one to five or six years—was not power per unit, but it was sheer number of units," explains Card.

Card says that if his company had 5GW of cell manufacturing capacity "I'd be sold out"; Suniva's capital announcement came with the news that Suniva has secured offtake agreements for the "majority" of the output of the new 4.5GW facility.

The Biden-era Inflation Reduction Act drove an 800% increase in US solar manufacturing capacity and even the more recent One Big Beautiful Bill Act (OBBBA) "didn't kill the 45X advanced manufacturing credit". While Card is less optimistic about the impacts of the policy landscape on deployment, he agrees that opportunities remain for manufacturers.

"We needed a policy framework that supported growing US manufacturing. There is much with OBBBA that supports US manufacturing growth in solar," he says. "You've seen a great uptick in announcements of factories since OBBBA."

The disparity between module and polysilicon production in the US is even greater than between module and cell production. Suniva has already signed a deal with domestic polysilicon provider Corning, and while Card did not comment on the source for the South Carolina facility, he says Corning "continues to be a valued supply chain partner".

When asked about the US polysilicon landscape more broadly, Card was bullish. "It's robust on poly," he says. "Certainly when you look at the US poly players, there's more than enough polysilicon created in the US to support the US industry."

By JP Casey

DYCM bets on integrated US solar manufacturing as demand and policy shift



DYCM's co-founder Sriram Das talks about US solar manufacturing, domestic supply chains and navigating shifting policy

Washington's solar policies may be ever-changing, but DYCM Power's central proposition has remained remarkably consistent. Co-founder Sriram Das believes the next phase of the US solar boom will reward companies that can deliver something the industry has long struggled to build: a reliable, domestically integrated supply chain for cells and modules.

Founded in December 2022 by Das and co-founder Jay Sharma, DYCM entered the US market with a straightforward proposition: to build an integrated domestic solar manufacturing business. In 2024, the company announced plans to develop a 6GW solar cell and module manufacturing facility backed by US$800 million in partnership with Macquarie Capital.

Das acknowledges that the company has adjusted its plans in response to changing policy and market conditions but says its end goal remains the same. "The overarching goal and the premise of the business haven't changed," he says. "We think the need for a reliable supply chain partner is pressing for our customers."

That reliability is central to DYCM's pitch. Das says the company has "prioritised transparent negotiations and consistency with customers", arguing that "module buyers have experienced delays, changing contract terms and other difficulties from suppliers in the past."

Located in Morgan Hill, California, the company's 150,000-square-foot module assembly plant is expected to begin commercial module shipments from its first heterojunction (HJT) production line in the fourth quarter of 2026. The next major piece is cell manufacturing, with the company set to outline its technology choice in due course.

Das says the company is making good progress on this but is not yet ready to disclose the technology. The decision is strategically important, as DYCM currently sees a gap in the US market for high-efficiency domestic cells, particularly for leading technologies such as HJT and TOPCon.

The company is deliberately limiting its module portfolio to around 720-730W for utility-scale, a 640W class and a residential class around 450-500W. Utility-scale products are expected to represent roughly two-thirds to three-quarters of output.

For DYCM, domestic sourcing is not a reaction to every new policy announcement. Das says he "instructed his team more than two years ago to develop US suppliers for every module component where possible." The company has now developed multiple suppliers for roughly 15 module components, with three or four sources for each item and at least one domestic option in most cases.

European equipment is being used for DYCM's manufacturing line, reflecting a strategy designed from the outset to avoid problematic supply-chain dependencies. Das views the policy environment as broadly positive because incentives encourage customers to buy domestic products, but argues that DYCM ultimately needs to be cost-competitive without relying on incentives to generate profits.

India is an obvious potential next step. Das says DYCM initially explored partnerships with Indian companies, but there is no immediate India expansion commitment. "India remains 'the obvious place'," Das says, "but it comes after the US manufacturing platform is established."

The immediate evidence that DYCM's strategy is gaining traction is customer demand. Das says the company's order book has increased almost tenfold in three months compared with the previous year, prompting him to begin looking for another building.

Das now has ambitions well beyond a small initial operation, saying DYCM ultimately wants to become a 10GW company. That ambition is also shaped by what Das sees happening beyond conventional utility-scale demand. Data centre developers need new power quickly, and he argues that solar remains one of the fastest routes to deployment.

By Shreeyashi Ojha

ES Foundry backs PERC despite US PV manufacturing shift to n-type



ES Foundry's Alex Zhu outlines how the US cell maker is betting on PERC while navigating shifting regulations and supply-chain constraints

ES Foundry is taking a cautious approach to US cell manufacturing, betting on established PERC technology as the foundation for its strategy today, while preparing to transition to a next-generation n-type technology as market conditions, intellectual property considerations and supply-chain availability become clearer.

ES Foundry CEO Alex Zhu says the company's strategy is centred on delivering commercially bankable US-made cells today. The company recently completed a 2GW expansion of its solar cell manufacturing capacity in Greenwood, South Carolina, taking its total capacity to 3GW. ES Foundry began operations with its first 1GW of capacity in 2025, and expects to have the expanded capacity fully ramped by October.

"In terms of actual production, we are the largest crystalline solar cell manufacturer in the US," Zhu says, contrasting this with a US solar manufacturing landscape characterised by numerous large announcements, some of which have not translated into operating capacity.

Zhu acknowledges that PERC does not offer the same efficiency potential as newer cell technologies, but argues that efficiency is only one part of the equation. "The reason we chose PERC is that it is very reliable and has a robust process window," he notes.

For ES Foundry, that maturity provides two important advantages. The first is bankability—financial institutions and customers are already familiar with PERC. The second is manufacturing. The US is rebuilding a solar manufacturing workforce after years in which much of the global cell production base migrated to Asia.

"Using PERC as a starting point is very good for us to train the local labour force without causing a significant loss of efficiency or reliability."

PERC is the starting point rather than the destination. Zhu says ES Foundry will eventually move from p-type to n-type technology, but the company has not yet decided which specific n-type architecture it will adopt. "We will move to n-type technology. However, we haven't decided which n-type technology we will go with because this depends on multiple things like IP issues, the supply chain and equipment availability."

Recent TOPCon disputes involving First Solar, JinkoSolar, Trina Solar, Maxeon and Canadian Solar underline the litigation risks facing manufacturers adopting the technology in the US.

President Trump's introduction of a 15% tariff on imports of polysilicon and its derivatives under Section 232 will significantly increase ES Foundry's wafer costs. "Our current wafer cost is, for example, from 4 cents to 7 cents imported from overseas. And after that, our cost will increase to like 15 cents plus 2 cents tariffs," Zhu says.

However, the higher cost of imported wafers could ultimately be offset by stronger demand for domestic-content modules as the price gap with imported products narrows. Domestic-content modules can benefit from an additional 10% investment tax credit, potentially reducing the overall cost of a solar project.

Zhu also points to the rapid growth of solar projects associated with AI data centres as another source of demand. "We see so many more project developers selling their projects to support the growth of AI data centres. At the same time, those customers also require domestic content because that will reduce the overall costs."

For ES Foundry, scaling US cell manufacturing goes beyond adding capacity—the company still faces gaps in both its upstream supply chain and local workforce. The company currently sources Chinese and non-Chinese polysilicon, with wafers produced in Southeast Asia. The workforce presents another challenge, prompting partnerships with MIT's Initiative for New Manufacturing and a local community college in Greenwood.

By Shreeyashi Ojha

'Every module will have perovskite in the 2030s'—Caelux on the impact of next-gen PV



Scott Graybeal, CEO of Caelux, discusses the company's unique perovskite technology approach and ambitious expansion plans

"We're talking about a step change in module performance without compromising lifetime," claims Scott Graybeal, chief executive officer of Caelux. The company produces perovskite solar products that are incorporated into solar module glass—a unique approach that allows their technology to fit into existing module supply lines, rather than requiring entirely new production processes.

Graybeal is confident that his company's tech will be part of a fundamental shift in solar technology over the coming years. "Every module in the world in the 2030s will have perovskite," he predicts.

Caelux puts perovskite material onto the solar glass directly, leaving the silicon cell within the module untouched. The reasons for pursuing this approach are both technical and financial. "One of the metrics we drive the business towards is the return on invested capital," Graybeal explains. Building out a module line would have extended the revenue horizon and increased costs to levels that would compromise returns on capital investments.

Traditional perovskite architecture can offer higher total efficiencies than Caelux's glass solution, Graybeal admits. However, he claims that if perovskite degrades in a traditional format, the whole product can be compromised, whereas the separation in Caelux's product means the underlying cell can still function.

Graybeal says the company's decision to "laser focus" on the perovskite material on solar glass means it has "developed expertise… and then [can] work with folks that make modules day in and day out, harness their knowledge, and use our technology to make their product better".

Over the summer, the company announced two 5GW "commercialisation" deals with Indian manufacturers Rayzon Solar and Navitas Solar, where it will aim to integrate its perovskite glass with the manufacturers' n-type TOPCon modules over a five-year partnership.

India is a "key strategic market" for Caelux, Graybeal says, highlighting policies such as India's Approved List of Models and Manufacturers (ALMM) and Production Linked Incentive (PLI) as effective in encouraging regional manufacturing.

The goal with the Rayzon and Navitas deals is to "build a backlog of business" that will one day justify an investment or co-investment in an Indian manufacturing facility. The partnerships are both aiming to begin producing TOPCon modules with perovskite glass in 2028-29.

While Caelux will expand in India and plans to bring some R&D staff there, its model focuses on developing processes at its headquarters in Baldwin Park, California and copying those exactly at "satellite" manufacturing locations. Graybeal confirms that Caelux's first manufacturing location will be in the US, with India likely to host the second.

Graybeal has been in the solar module technology business for 19 years and sees the coming generation of technology as a "step change". "We used to grind one-tenth of a percent, two-tenths of a percent…a half percent would be a huge innovation," Graybeal says. "This technology is five to six to seven percent absolute efficiency improvement."

He believes that every module in the 2030s will contain perovskite largely because there "isn't a path for silicon to have a significant boost in its output", and growing demand from electrification will call for more efficient solar installations.

On durability concerns, Graybeal claims the company has addressed fundamental chemistry issues. "We've done a lot with the fundamentals of the chemistry, whether it's through additives, different structures or different process techniques, which has enabled us to really achieve the durability results," he says, claiming the company is "already in the process of qualification and certification of the technology" and that its tech can "support 25-year lifetimes".

By Will Norman

'We'll be producing heterojunction this year in the US,' says SEG Solar CEO



Jim Wood, SEG Solar's CEO, explains the company's US manufacturing roadmap and why it chose heterojunction technology for its new facilities

Domestic PV manufacturing activity in the US has continued to grow this year, with many announcements from companies building new facilities or starting commercial production. One of those companies is Houston-based manufacturer SEG Solar, which announced in May a second module assembly plant and a third in June. Both will add a combined 8.6GW of annual nameplate capacity, bringing the company's total module nameplate capacity in the US to 10.6GW.

Jim Wood, CEO at SEG Solar, says the second module assembly plant, which opened in August, is set to begin commercial operations in the fourth quarter of 2026. Construction of the third facility is expected to finish in March or April of 2027. With module production beginning in the coming months, this will bring heterojunction (HJT) module production online. "We'll be producing heterojunction this year in the US," Wood says.

The company is also working on building a 2GW HJT solar cell processing facility in the US. Until the solar cell processing plant is up and running, Wood says the company will use solar cells from its Indonesia facility for part of this year, then pivot to the facility in the Philippines. This comes as preliminary antidumping and countervailing duties on imports from Indonesia were issued earlier this year.

"With IP and policy and those types of things, we want to just make sure that we still can produce solar panels for our customer if there's an injunction on n-type TOPCon that could freeze the US market"

"Prior to the AD/CVD [anti-dumping and countervailing duty case, we shipped enough cells to kind of keep us going until sometime in Q3 of this year," explains Wood. The Philippines facility is a short-term solution, while the Indonesia facility continues to operate due to continued demand for domestic content in Southeast Asia.

Also in Indonesia, the manufacturer is building an ingot and wafer manufacturing plant with 3GW annual nameplate capacity, which will supply both the Indonesian and Philippines solar cell processing plants. Wood forecasts that production will begin at the end of this year or by Q1 2027.

When asked about building an ingot and wafer facility in the US, Wood did not discard the possibility. "Ingot and wafer [manufacturing] is expensive. It's a huge and significant investment," he says. "We tend to build things first outside of the US, learn how to do it, make our mistakes where they're going to be cheaper, and then we build it in the US after we know what we're doing."

Building ingot and wafer capacity in the US will take time and policy support that extends beyond 2030. "If we could get an extension of the incentives here in the US, then it would give us a clear pathway to continue to go down the path of doing ingot and wafer in the US."

Behind the company's technology roadmap, the technology of choice is HJT. Wood explains the reason is due to IP issues around TOPCon in the US, with two lines in the Houston factory dedicated to that technology.

"With IP and policy and those types of things, we want to just make sure that we still can produce solar panels for our customer if there's an injunction on n-type TOPCon that could freeze the US market," says Wood, adding that "the IP around the actual product of heterojunction is expired, so there's a lot of safety around heterojunction in the US."

When asked about the fact that HJT seems to have lost favour in China, Wood explains the reason was cost. "Our estimates are that it's about a penny more to produce it. When you look at the US market, it's different from the rest of the world. It's one of the few havens of margin left on the planet for PV."

The module price difference in the US versus the rest of the world could help reduce the cost difference of manufacturing HJT modules over TOPCon, and help make the bridge from PERC to n-type technology before the next generational jump to perovskite.

According to Wood, more recent announcements to build HJT capacity might find difficulty in procuring the necessary equipment from China. "I could definitely see companies that didn't already secure their HJT equipment having issues, because China hit the brakes very recently in the last 30 days on heterojunction exportation of equipment to the US."

By Jonathan Touriño Jacobo

'Crystalline silicon is the future'

T1 Energy's CEO Daniel Barcelo explains his optimism about US solar manufacturing and how it can deliver on power demand growth



Despite policy setbacks solar PV faced last year in the US, the technology keeps on shining. Despite witnessing a year-on-year drop in Q1 2026, solar PV along with energy storage still accounted for 91% of all new power additions to the US grid in the first three months of the year.

Daniel Barcelo, CEO of US manufacturer T1 Energy, shares this optimistic spirit. "Crystalline silicon is the future. Silicon is this century, oil is last century," Barcelo says.

"We, as a society, need to develop all of the infrastructure in the ecosystem around crystalline silicon, which is foundational for semiconductor manufacturing," explains Barcelo, noting that solar's growth creates demand for lower-grade polysilicon, allowing producers to make higher-quality polysilicon for the semiconductor market.

Barcelo's optimism extends to the industry as a whole. He draws a parallel with the US natural gas market in the 80s, noting that deregulation enabled market growth. "This was all about letting the market go, allowing technology, allowing capital and allowing risk-taking, and that's not going to be an issue."

He adds that Tesla's announcement to build a 100GW annual nameplate capacity cell and module plant in the US or Corning entering the wafer manufacturing scene are the types of action needed for the industry to grow. The outcome of the Section 232 investigation for polysilicon could create strong incentives for the US to build more polysilicon production, which will have a domino effect down the supply chain.

T1 Energy's story did not start in the solar industry, but with energy storage. Barcelo explains that the company raised financing in 2019 and entered the European scene with lithium iron phosphate batteries before moving to solar PV in the US two years ago.

"We saw that the need for the American grid was more profound. We actually pivoted from storage to solar, because we saw that solar in the United States had a much more open market for American companies," Barcelo says, adding that solar PV and energy storage are the only technologies that can meet today's power needs.

The company shifted when it acquired Trina Solar's US assets in 2024, which included a module assembly plant in Dallas, Texas, under construction at the time, as well as a polysilicon supply agreement with Hemlock Semiconductor. Since the acquisition, the module assembly plant reached full operations last November with 5GW annual nameplate capacity, while the solar cell plant in Austin, Texas, began construction in December 2025.

The cell plant will be completed in two phases, the first bringing 2.1GW annual nameplate capacity with operations set to begin in Q4 2026. A second phase will expand capacity to 5.3GW, with potential for a third phase increasing capacity to 8GW.

"If the market demand is there and the demand signals from the hyperscalers, or through the utility-scale developers, are there and we have access to capital, we're going to grow," says Barcelo.

For Barcelo, increased power demand growth in coming years is key for continued appetite for solar modules once investment tax credits expire. "That demand is going to drive a market response," he says, with solar and storage at the forefront.

Another key advantage of acquiring Trina Solar's assets was the TOPCon technology used to produce modules, not PERC as many US players have adopted to avoid legal disputes. "When we bought these assets, what we

"We actually pivoted from storage to solar, because we saw that solar in the United States had a much more open market for American companies"

were able to do was get in the market with the best commercial tech right now," says Barcelo.

In an interesting development, T1 Energy came full circle in June with the acquisition of Kore Power's NRI division, which specialises in utility-scale battery energy storage systems. "We felt that NRI offers a very strong engineering platform that we wanted to incorporate into T1 Energy in order to have a better customer focus," Barcelo says.

His vision is to sell a partnership with large-scale utility developers and offer the best products for both solar PV and energy storage, capitalising on the urgent need to meet massive power demand from data centres as quickly as possible.

By Jonathan Touriño Jacobo

Leapfrogging perovskite from Silicon Valley to the mainstream



Scott Wharton, CEO of Tandem PV, discusses his company's plans for perovskite tandem solar modules and its roots in Silicon Valley

Scott Wharton, CEO of Tandem PV, believes perovskite-tandem solar technology will "dominate the market" within six years—and he credits Silicon Valley's culture of innovation for making that possible. Naysayers who doubt the technology's long-term impact, he argues, "don't understand economics".

The past 18 months have been transformative for the Silicon Valley startup. In March 2025, Tandem PV raised US$50 million from venture capital firm Eclipse to fund a commercial-scale tandem module production line. By April, it had launched operations at a demonstration facility in Fremont, California, and in August it secured a US$7.7 million grant from the US Department of Energy (DOE) to accelerate rollout of its tandem modules, which the company claims achieve 29.7% conversion efficiency.

In June, former US energy secretary Jennifer Granholm joined Tandem PV's board—a move Wharton describes as a strong vote of confidence. "Jennifer Granholm is not on many boards at all, so it's a real honour to have her participating with us. Same with the DOE—I think we were the only company in the solar space that won a grant for that particular programme."

Wharton, a serial entrepreneur rather than a solar specialist, sets out three requirements for commercialising perovskites: efficiency, durability and manufacturability.

Tandem PV has shown efficiency, he says, with its 29.7% demonstration modules, and he claims that the company has achieved less than 1% degradation per year on its products. Those claims have apparently been verified by bodies including the National Renewable Energy Laboratory (now the National Laboratory of the Rockies) and Renewable Energy Testing Centre (RETC), though that certification has been absent from the company's public announcements.

"I think there have been a bunch of announcements in the industry, but they don't really mean anything unless you have the durability to be commercially viable," he says.

"And then the third thing is, can you take all that and not just make it on a small form factor, but can you do it on something bigger? And I think that's where we've gone recently. In our demo facility, we're now showing that we're making large things that are about as good as what we did in R&D."

On overcoming the degradation problem that has plagued perovskite developers for years, Wharton credits his team—including roughly 20 PhDs and CTO Colin Bailie, who helped develop one of the world's first silicon-perovskite tandem cells at Stanford. "A couple of years ago we basically got the perovskite stable enough that we could start seeing other failure conditions. It's kind of like peeling away layers of an onion—unless you get your core perovskite layer stable, you never see all the other failure conditions."

Tandem PV expects to begin paid trials with more than a dozen major US independent power producers before year-end, aiming not for profit but to prove the product's bankability in the field. A gigafactory-scale facility is planned by 2028.

Tandem PV is targeting the utility-scale sector—a departure from perovskite's reputation as a niche technology for space or small rooftop applications. Wharton pushes back firmly against sceptics who argue that perovskite development is a wasted effort given silicon PV's maturity.

"If you have a 22% efficiency panel and it works, great. No arguments there." But he argues that higher efficiency fundamentally changes the economics: "The more efficiency you have, you need less labour, less land, less balance of system, and that lowers the overall cost. The whole reason the world went from PERC to TOPCon was to get a 2% efficiency boost. Tandems are 7-12%."

Crucially, he frames tandem as additive rather than disruptive to existing infrastructure: "Unlike the shift from PERC to TOPCon; this is not a replacement. Because they're tandems, you could leverage all of the existing TOPCon infrastructure. Once you have products out there that are at 30% that are cheaper for customers, no one will buy a 22% panel anymore. If you're not at 30%, you're out of business—it's a fundamental economic shift."

Wharton frames the technology's rise in pragmatic rather than environmental terms, even as he acknowledges its climate significance. "It doesn't matter what your ideology is... I picked it because it had better economics and physics—because you can ask people to do something that is good for the environment, but if it's not cheaper, most people will not do it. I'm counting on people doing this because they're greedy, and then solving climate change is a nice little after-benefit."

Wharton sees perovskite's momentum on the US West Coast—alongside companies like Caelux and Swift Solar—as evidence of a distinctly American "culture of leapfrogging". Rather than compete directly with China's dominance in silicon manufacturing, he argues the US advantage lies in jumping to the next technological frontier, much as it did with mobile phones and AI.

"It's very hard once you've lost an industry... I think the culture in the US is more like, well, we lost that—let's leapfrog and go to the next level. We know how to innovate and go faster and leapfrog in a new area."

Looking ahead, Wharton is confident in the trajectory: "I think we have a pretty well-trodden path to becoming a multi-billion-dollar company and a leader in this space by scaling up. We just have the small matter of doing the work, but that's the fun part."

By Will Norman

How can the US build a full domestic PV ecosystem? Turn to p.26 to find out.

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More than module assembly: building a resilient solar ecosystem in the US

Supply chain | As the United States races to establish a domestic solar supply chain, manufacturers face complex decisions around technology selection, equipment sourcing, workforce development and long-term sustainability. Markus Beck of RCT Solutions tells Ben Willis how US PV manufacturing can be sustained beyond the current boom



The rapid expansion of solar manufacturing in the United States represents one of the most significant industrial buildouts in recent memory. Yet beneath the headline announcements of multi-gigawatt facilities lies a complex web of challenges that will determine whether this manufacturing renaissance achieves long-term sustainability or becomes another cautionary tale of misaligned incentives and missed opportunities.

Markus Beck, who leads the US operations of RCT Solutions, a German-founded engineering and consulting firm that advises on building PV manufacturing lines, and previously served as a programme manager in the US Department of Energy's Solar Energy Technologies Office, offers a clear-eyed assessment of the current trajectory. His perspective, informed by decades in the industry and recent government service, reveals an ecosystem struggling with fundamental questions about technology choices, supply chain resilience, workforce readiness and the policy frameworks needed to support truly domestic manufacturing.

The IRA's unintended consequences

The structure of the Inflation Reduction Act (IRA) has profoundly shaped—and in some ways distorted—how the US solar supply chain is developing, Beck says. He notes that the legislation provided the highest incentives for module assembly while offering diminishing support as complexity and capital requirements increased further up the supply chain.

"The Inflation Reduction Act … unfortunately was not structured the way it could have been," Beck observes. The result is a surge in module assembly capacity that has reached approximately 100GW nameplate—far exceeding realistic market demand—while cell manufacturing has lagged significantly behind.

This situation began shifting only after the One Big Beautiful Bill Act reduced the runway for advanced manufacturing production credits, and Section 232 tariffs and numerous rounds of anti-dumping and countervailing duties created additional pressure and added sticks to tax credit carrots. This has triggered investment in cell production, and that buildout is now happening, "which is great", Beck says. But inevitably, the focus is now shifting still further upstream, to ingots and wafers.

Here, the challenges multiply. Beck characterises investment in ingot and wafer production as "certainly complex", requiring substantially higher capital and technical expertise. While companies like Hanwha and Corning have announced plans, progress remains insufficient. Meanwhile, upstream equipment manufacturing has seen virtually no development: "We have done nothing, literally, on the equipment side. Nothing."

The equipment sourcing dilemma

One of the most consequential decisions facing US manufacturers involves equipment sourcing—a choice that carries implications extending far beyond initial capital costs to encompass operational efficiency, supply chain security, innovation potential and long-term competitiveness.

Chinese equipment dominates the US market, driven by several factors. Beck acknowledges there exists "a perception that Chinese equipment is the best equipment", supported by the reality that much of it operates at scale globally. Price competitiveness remains significant factor for Chinese producers, to the extent that "they now are selling equipment under terms which if you and I could buy a car or a house like that, we would be thrilled". Chinese suppliers also offer turnkey solutions that simplify procurement and reduce risk for manufacturers lacking deep technical expertise.

However, Beck argues this equipment sourcing strategy overlooks critical considerations. While Chinese equipment may offer lower upfront capital costs, he suggests that total operational costs over a facility's five to seven-year lifespan could favour alternative suppliers when factoring in electricity consumption, water usage, chemical consumption and maintenance requirements. Additionally, concerns around cybersecurity, spare parts availability and the technical workforce needed to maintain equipment should influence sourcing decisions.

European equipment producers or consortia offer alternatives, though they remain relatively unknown in the US market. On the module side,



Credit: Fraunhofer ISE

US PV companies are working with European research institutes such as Fraunhofer ISE due to the lack of domestic R&D expertise

companies such as Ecoprogetti and Mondragon provide turnkey solutions. For cell manufacturing, a consortium led by Von Ardenne offers TOPCon and heterojunction lines. For ingot and wafer production, Rena, PVA TePla and others have formed partnerships.

Yet these options face significant barriers. Higher capital costs create challenges in a capital-constrained environment where manufacturers must raise funds not only for equipment and facilities but also for operational cash to sustain operations during ramp-up periods.

The equipment sourcing decision becomes even more critical when considering future-proofing and innovation potential. Beck advocates for manufacturers seeking differentiation to build relationships with equipment vendors across individual process steps—screen printing, diffusion and other stages—enabling collaborative innovation rather than accepting turnkey solutions as fixed systems.

He illustrates the risk of inadequate planning with the example of cell-cutting technology. Facilities designed only for full-size cells cannot easily adapt to half-cut, third-cut or quarter-cut cells without edge passivation technology, adequate floor space and properly sized utilities. "If you don't have edge passivation technology in your cell line, you have no space, you know, your utilities aren't sized to handle that... you may have shot yourself in the foot," Beck warns.

The workforce crisis: an overlooked challenge

Perhaps Beck's most striking observation concerns workforce development—or rather, the lack of it. Despite widespread acknowledgement that skilled workforce shortages are among the top three challenges facing US solar manufacturers, he reports that RCT Solutions receives very few takers for its workforce training offerings in the United States.

"It's mind-boggling because when I was in the government, I would hear from everyone we talked to, one of the top three problems was always workforce, or lack of a skilled workforce," Beck notes. He created a workforce training programme during his time in government that attracted numerous applications before the current administration discontinued funding.

This stands in stark contrast to India, where workforce training forms a component of virtually every project RCT undertakes. The consequences of inadequate training manifest in quality issues and suboptimal uptimes in module assembly operations—problems that proper workforce development could address.

RCT Solutions has developed comprehensive training programmes spanning online learning, classroom instruction and hands-on equipment training, with content that can integrate into clients' learning management systems. Yet US manufacturers have shown limited interest, even as they struggle with operational challenges, Beck says.

This workforce gap reflects broader structural challenges in US manufacturing. Beck notes that less than 10% of US GDP derives from manufacturing, and cultural resistance to shift work and weekend schedules creates additional hurdles. The US has also failed to maintain its technical knowledge base in solar manufacturing, having lost much of its DNA in advanced manufacturing. Research institutes and universities have been underfunded, equipment vendor capacity has atrophied and the manufacturing workforce has dispersed.

Building a resilient domestic ecosystem

Beck argues for developing a more complete domestic solar ecosystem in the US that extends beyond assembly operations to encompass R&D, equipment manufacturing and the full depth of the supply chain. His vision of supply chain resilience emphasises diversity across multiple dimensions: technology,

geography, sourcing and suppliers.

Current US manufacturing lacks this resilience. While manufacturers can source equipment from different Chinese companies, geographic concentration creates vulnerability to disruptions—whether from natural disasters, port closures or geopolitical tensions. "There can be things that happen that make your source inaccessible, and then you have no alternative to fall back on," Beck explains.

The Inflation Reduction Act's treatment of "substantial transformation" illustrates how current policy fails to incentivise true domestic value addition. Under existing rules, importing aluminium module profiles from Vietnam but then cutting the corners and drilling the holes in the US qualifies the frame as domestic content. Similarly, assembling imported wire, junction boxes and diodes creates a "domestic" junction box despite minimal US value-add beyond labour.

Beck advocates for a more strategic approach to building domestic capability, potentially modelled on Sematech, the semiconductor industry consortium that successfully advanced US competitiveness. He proposed a US$200 million budget for such an initiative during his government service, though Congress did not approve the funding. Such a consortium could enable companies to share R&D costs, develop shared intellectual property under appropriate protections and provide hands-on workforce training.

The challenge of building domestic equipment manufacturing capability illustrates the chicken-and-egg problem facing the ecosystem. Equipment vendors need multiple customers to justify investment in US production, but individual manufacturers cannot single-handedly support such investments. Beck suggests that co-financing arrangements among manufacturers could help overcome this barrier.

He identifies specific opportunities for near-term progress: "Let's make screens in the United States. How complicated can it be? Let's make crucibles. It's not that complicated, right? We have the international roadmap for solar; it would be nice to have a roadmap that the US industry could come together around and say, this is the roadmap for how we build out our ecosystem." This phased approach to supply chain development could create momentum while managing capital requirements.

Beck also highlights opportunities in areas where the US could "out-compete" through innovation rather than cost reduction. Kerfless wafering technology, for example, could dramatically improve polysilicon yield. Alternatively, kerf recycling—the approach taken by Highland Materials—could recover significant value from Corning and Hanwha operations.

The vertical integration imperative

Beck advocates vertical integration, arguing it offers the best path forward for US manufacturers despite inherent challenges. Vertical integration addresses the financing difficulties that plague piecemeal development: cell factories need bankable offtake agreements from module manufacturers while also requiring secure wafer supply. These interdependencies create barriers when approached one segment at a time.

Vertical integration also enables more flexible business models where profitability concentrates at the end product rather than requiring every segment to generate margins independently—a structure that may prove more viable given market conditions. The trend is already visible: Hanwha Qcells now has vertically integrated operations, SEG Solar is expanding from modules into cells and others such as Inox (formerly Boviet) are pursuing similar strategies.

However, vertical integration requires substantial capital and the ability to convince financial markets of long-term viability—resources not available to all manufacturers. This reality suggests the market will likely support some merchant cell and wafer providers alongside vertically integrated players.

Technology choices and innovation imperatives

The rush toward heterojunction technology among US manufacturers concerns Beck, who suggests these decisions may be driven more by perceived intellectual property issues around TOPCon than by comprehensive analysis of all relevant factors. He advocates for technology diversity, arguing that different cell architectures serve different applications and market segments.

More fundamentally, Beck questions whether US manufacturers are thinking strategically about innovation and differentiation. Most module manufacturers in the US lack R&D and engineering capabilities, simply assembling bills of materials provided by others. "That's, in my mind, not sustainable, given that you have this massive overcapacity," Beck argues.

He envisions application-specific innovation as a potential differentiation strategy: modules optimised for specific environments, designed for particular lifetime requirements, or engineered for unique mechanical or electrical demands. A rooftop system, for example, does not benefit from bifaciality but could leverage the highest efficiency back-contact cells with conductive backsheets instead of traditional stringing.

Such differentiation requires engineering capability and willingness to invest in R&D—resources that current business models struggle to support. The challenge extends to partnerships with research institutions. While companies like Talon PV are partnering with Germany's Fraunhofer ISE, and Suniva is working with ISC Konstanz, such collaborations remain relatively rare in the US, and are notably with European rather than US institutions.

Policy and market outlook

Looking ahead three years, Beck anticipates the US will have 30-40GW of crystalline silicon cell capacity by nameplate, with production matching market demand. He expects 10-15GW of ingot and wafer capacity, with existing operations achieving sustainability and new facilities completing their ramps. Polysilicon may see modest capacity additions, potentially from kerf recycling operations.

However, Beck emphasises the need for an honest assessment of structural challenges. The United States has lost much of its solar manufacturing expertise, underfunded research and education, lacks equipment vendor infrastructure and maintains a manufacturing sector that represents less than 10% of GDP.

Policy stability would help, though Beck acknowledges the political reality of 10-year limits on tax incentives. He suggests that annual reviews of incentive levels—similar to the adjustable minimum import price mechanism—could provide more responsive policy while maintaining some predictability.

On the demand side, Beck questions whether utility-scale ground-mount deployment can continue indefinitely given land constraints and grid infrastructure limitations. He advocates for greater emphasis on distributed generation—rooftop systems, agrivoltaics, floating solar, infrastructure integration and vertical installations—that could reduce dependence on federal tax credits while easing grid constraints.

"If we can question the status quo and the market, yes, it would be great if we could deploy 100GW or utility-scale per year, absolutely. But, you know, maybe if we shift a little bit and we do a little bit more of PV everywhere, there are still applications that are just different that we could do that may not have to depend so much on federal tax credits and are more driven by the fact that an individual, a family, or a corporation can then self-consume the electricity."

The path forward requires honest assessment of current limitations, strategic investment in ecosystem development, and recognition that building a resilient domestic supply chain demands more than assembling imported components on US soil. As Beck's analysis makes clear, the decisions manufacturers make today about technology, equipment, workforce and partnerships will determine whether the current manufacturing buildout creates lasting competitive advantage or simply replicates vulnerabilities in a different geographic location. ■

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From megawatts to gigawatts: how space is pulling silicon PV off the ground

Space | A boom in the satellite business is creating new opportunities for terrestrial PV manufacturers in space. Catherine Early explores the challenges of adapting crystalline silicon solar technology to the demands of operating in space



Credit: NASA

Solar cells in space have a long heritage. Vanguard 1 became the world's first solar-powered satellite in 1958, and remains in orbit today, the oldest artificial object to do so. Solar cells also made it to the Moon in 1969, to the surface of Mars in 2004 and orbited Jupiter in 2016.

For most of the decades since, space photovoltaics has been a boutique trade. Cells have been made in tiny numbers for a handful of very expensive spacecraft, where longevity in orbit and a few extra percentage points of efficiency justified the high price.

Space PV applications have long been dominated by 'III-V' cells, a reference to the placing of raw material elements gallium and arsenic on the periodic table.

NASA's Orion spacecraft is powered by a huge gallium arsenide solar array, but silicon PV manufacturers are now eyeing the opportunities in space solar

These cells have prevailed due to their high conversion efficiencies, exceeding 32%, and ability to tolerate the extreme space environment, where radiation and temperature extremes can degrade cells rapidly and shorten their working life.

But the status quo has been turned upside down by the proliferation of spacecraft now being sent into low-Earth-orbit

(LEO). Goldman Sachs forecasts that as many as 70,000 satellites will launch over the next five years.

Spacecraft launched into LEO mostly serve applications in satellite internet, remote sensing and space communications. Elon Musk's internet network Starlink already has more than 11,000 spacecraft in orbit, while Amazon's rival LEO network has permission to launch roughly 7,700 by 2035.

Such volumes are rewriting the arithmetic of power. A 2024 Caltech presentation estimated that a Starlink satellite costs roughly US$300,000 and draws about 6kW. At around US$100 per watt, traditional III-V cells would add US$600,000, twice the cost of the satellite. "This is why Starlink uses silicon cells at US$0.5/W," the presentation states.

Supply matters as much as price. Commercial satellite companies need a manufacturing scale that specialist III-V producers cannot easily provide. Many such commercial satellites being sent up today are designed to last just five years, making expensive solar panels designed to last much longer even less viable.

Manufacturing remains a challenge

But manufacturing is challenging, and volumes are small, relative to the size of the burgeoning market. III-V suppliers produce about 2MW of cells a year—enough to power just a small fraction of the space industry's current annual demand, according to venture capitalist firm Shield Capital. This shortage will only grow as the satellite industry is projected to grow by seven times by 2035, Goldman Sachs predicts.

In addition, 98% of the world's supply of raw gallium is produced by China, which, in 2024, banned the export of gallium to the US as part of a larger critical minerals ban. It also produces more than 60% of the germanium required for III-V solar cells.

Boeing subsidiary Spectrolab has supplied the market since 1956. The manufacturer can produce nearly 500kW a year, enough to power around 30 satellites, according to its website.

New Mexico-based SolAero has supplied missions including Parker Solar Probe and Mars InSight Lander. Now owned by Rocket Lab, SolAero's production line has an annual production capacity of more than 1MW. Terrestrial heterojunction (HJT) cells, by contrast, are produced at gigawatt scale.

Incumbents are responding to the challenges. In September, Rocket Lab released the latest iteration of its Inverted Metamorphic (IMM) Apex III-V cell, dropping the supply-constrained germanium from the design.

The cell is a mechanical and electrical drop-in replacement for heritage solar cell products, meaning customers can integrate it into existing systems without major investments to re-tool for new cell technology, according to the company. The firm says it will be able to manufacture in 'multi-100kW volumes' to meet growing demand.

Silicon steps into the gap

However, many believe that the headwinds facing III-V cells are creating a gap that could be filled by the massive manufacturing output of the mainstream crystalline silicon PV sector.

The question is to what extent the economics of terrestrial silicon can adapt to meet the extreme environments of LEO. Several manufacturers are working on adaptations for terrestrial silicon technologies.

In August, US-based Source Energy and the Fraunhofer Institute for Solar Energy Systems (ISE) announced a new product line for satellites based on silicon solar cells. The partners say they can manufacture panels for under US$5 per watt and deliver within six months.

They can achieve this price and speed due to using 'shingle matrix' manufacturing process, where cells are cut into strips and overlapped like brickwork and bonded with conductive adhesive, allowing current to flow around any area damaged by debris.

Prototypes reached 18.8% efficiency under AM0 (the sunlight spectrum outside Earth's atmosphere) and 252W/kg. Lab test results project that the cells can retain 76% of power after seven years.

"Three features make the shingle-matrix interconnection perfect for space," explains Najwa Abdel Latif, project manager at Fraunhofer ISE: "Resilience to localised physical damage from impacts by small objects in space, flexibility in layout and tolerance to extreme temperature differences."

The shingle-matrix technology is compatible with wafer-based solar cells featuring front and back contacts, such as PERC or silicon HJT, without having to adapt production lines, and will also be able to integrate perovskite silicon tandems in future, she adds.

'Moving away from the older generation'

California-based Swift Solar is looking to combine HJT silicon with perovskite technology in tandem cells both for terrestrial applications and space-based uses. The company believes the space solar sector will converge on heterojunction silicon and tandem perovskite technology, explains Geoffrey Dunican, Swift Solar's vice president of commercial strategy and partnerships.

"We are at the nexus of moving away from the older generation silicon PERC technology and the III-V technology to meet somewhere in the middle. HJT and tandem perovskite are going to really be high volume, minimal cost and better performance," he says.

Swift Solar's technology has flown on three space flights, with "essentially no degradation" after around nine months in space, Dunicane says. "We're in the process of working with the commercial sector as well as the federal sector on additional test flights and getting cells tested," he adds.

In March, the firm acquired manufacturing assets and intellectual property of European solar manufacturer Meyer Burger, putting the company on track to operate gigawatt-scale solar manufacturing in the US, from 2028.

Fellow US-based manufacturer Ascent Solar's thin-film modules have been tested on the International Space Station (ISS) by NASA's Marshall Space Flight Center. Its assemblies include copper indium gallium (di)selenide cells (CIGS), inverted metamorphic multi-junction cells and various protective coatings.

In 2026, its thin-film solar modules encapsulated in fluorinated ethylene propylene (FEP)—a high-performance fluoropolymer film rather than heavy glass or standard ethylene-vinyl acetate—underwent accelerated atomic oxygen exposure testing equivalent to approximately six months of operation in the LEO environment.

Post-test inspection and electrical performance characterisation showed no measurable performance degradation, and no observable atomic oxygen damage to the encapsulated modules, according to its CEO Paul Warley.

Side effects from an experiment by NASA on Corin coatings for CIGS cells, which used a polymer layer made of colourless polyimide layer to coat and protect cells, found that the cells possi-

bly self-annealed, or 'healed' damage sustained by radiation, Warley explains.

Warley is considering a further test to certify that finding. But if it is true, the company's technology will be in a "different ballpark" to other silicon technologies, whose efficiency typically falls from around 22% to 11-14% after five years due to radiation, he says.

Initiatives in the US, China and Europe

The US government is keen to support a domestic supply of PV cells for space, and has made domestic sourcing a requirement for federal contracts. In August, the Department of Energy (DOE) Integrated Energy Systems Office (IESO) announced a grant pot totalling US$12 million for research and development (R&D) projects supporting solar panels in space applications.

University and industry research laboratories can win up to US$1.5 million for projects advancing manufacturing methods and improvements in performance of durability of solar cells, and up to US$2 million for projects focusing on manufacturing processes capable of scaling to high-volume production of module prototypes for space or near-space environments.

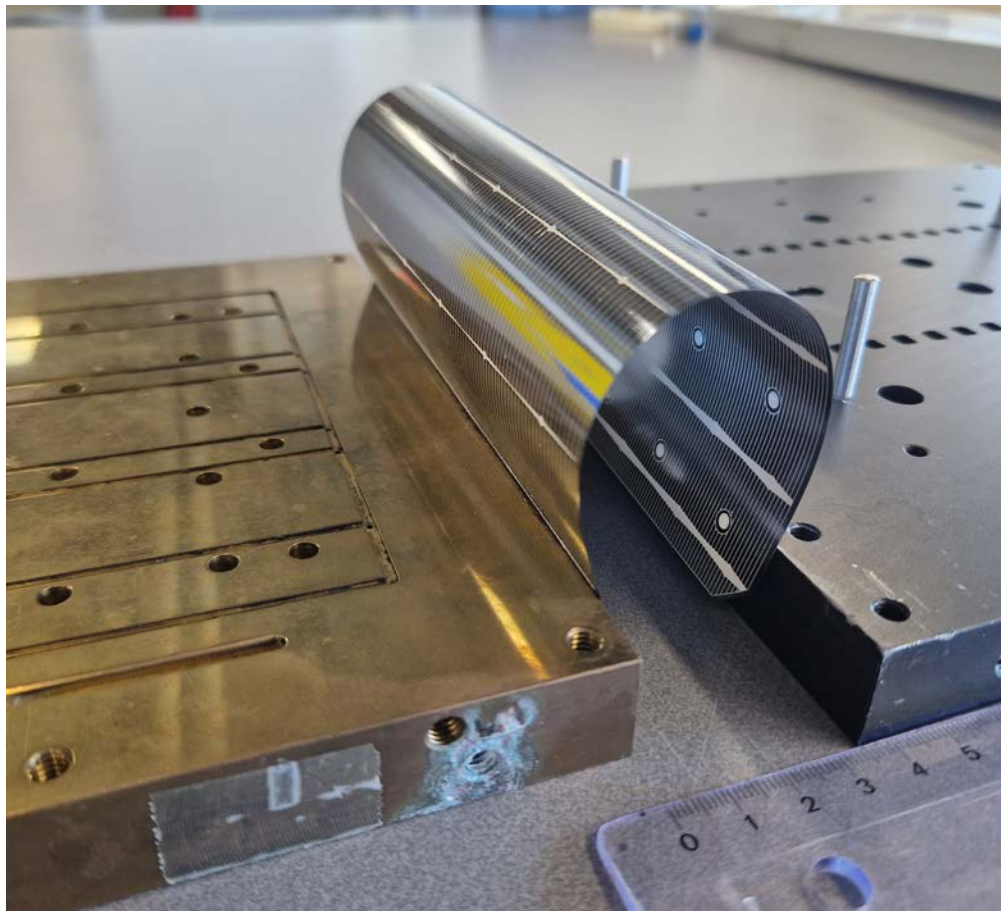
The DOE's grant is an "exciting" development, according to Yao Yue Lao, senior project engineer at the Aerospace Corporation. She says that the department, along with the National Laboratory of the Rockies (NLR) (formerly known as the National Renewable Energy Laboratory, or NREL), was very much involved in developing the gallium arsenide technologies currently used in space

"The DOE was critically involved in the previous iteration of space PV so it's great to see the department leveraging its PV expertise to develop the PV next technology for space," Lao says.

Meanwhile in China, JA Solar is testing HJT modules in LEO aboard a Kuaizhou-11 rocket, launched from the Jiuquan Satellite Launch Center in September.

By comparing in-orbit performance data with results from ground-based simulations, the company will assess the long-term reliability and degradation of its technology for both space exploration and commercial space applications.

"The technology will require long-term validation, but we believe it is a direction worth pursuing," says Dr Ouyang Zi, chief technology officer of JA Solar.



Credit: TNO

Dutch research organisation TNO is exploring combiniations of terrestrial PV and advanced space solar technologies

The EU is also in the line-up for the solar space race. The European Space Agency (ESA) has several routes for early technology development and de-risking of new technologies for space-grade solar cells, and has expanded its budgets and financial instruments to support R&D, according to Harald Kerp, senior business developer at Dutch research organisation TNO.

However, though the EU has satellite building companies, and solar panel producers, it is lagging the US and China slightly on development of space-grade solar cells, he says.

To help fill the bloc's gap, TNO is partnering with various companies including Airbus Netherlands GTM Advanced Structures, the European Space Agency and its lab ESTEC, European research and development institutes, material suppliers and other companies along the value chain to explore innovations in combining terrestrial PV with advanced space solar technologies.

"It is very important that the whole ecosystem will team up to get these European factories off the ground," he says.

It plans to develop ultra-thin HJT silicon solar cells combined with back-contact architecture, enabling low weight, high radiation hardness and compatibility with automated, high-precision 'pick-and-place' manufacturing, an approach known for its flexibility in product design and compatibility with automated industrial processes.

The organisation has produced first prototypes and completed early tests such as thermal cycling, and is now working toward scaling up manufacturing, explains Kerp.

Testing and certification: slow and expensive

Testing and certification are some of the biggest barriers for PV manufacturers entering the space solar market, according to Lao. To conduct full qualification testing in-house, a manufacturer would need expensive facilities, including large thermal-vacuum chambers, equipment for extreme thermal cycling and infrastructure to assess outgassing, radiation, UV and atomic oxygen exposure, she says.

According to Lao, who chairs the panel of the American Institute of Aeronautics and Astronautics' (AIAA) standard S-111A-2014, which covers solar cell testing, many commercial players do not fully complete the tests, instead prioritising only the most critical risks and relying on in-orbit performance to flag any problems.

"A lot of the testing involves characterising how panels will perform in the space environment, under radiation, UV and atomic oxygen. But if all they care about is whether the panel deploys and produces power, they might just say, 'this is good enough, we'll launch it and see how it performs'," she says.

This is the strategy used by Musk's SpaceX, according to many commentators. "They simply started with taking earth-grade cells and putting them on the satellites. They have their own launch capacity, so it's easy for them to do frequent launches to test a new batch of cells," Kerp says.

Testing also has to be adapted to the specific challenges of space, Lao explains. For example, radiation testing for new solar cell materials, such as perovskites, is still at an early stage, because their behaviour under different particle energies does not map cleanly onto the long-established standards used for crystalline silicon and III–V space cells.

In addition, module integration needs its own tests for issues, such as stack design and adhesives, which will not outgas or fail under extreme thermal cycling. While commercial companies are now focused on solving these module-level engineering problems, university research has only partially progressed beyond cell-level testing, she says.

Gigawatts in orbit

The trend towards silicon could face even steeper challenges in the near future. If talk of power grids in space to supplement power from degrading solar cells, and space-based data centres come to fruition, gigawatts of demand in space will be created—levels "unheard of" in the current megawatt space solar market, Lao says.

"Space data centres would mean an insane increase in power—around a three orders of magnitude jump," she says.

The solar arrays on data centres would need to be really large to make up for the lack of efficiency of silicon cells, she points out. And the larger the arrays are, the higher the chances that they will be hit by space debris, she adds.

"If you're going to scale up to that level, you're going to have a lot of new challenges to consider," she says.

Dunican is already talking to customers about the potential for space-based data centres. "We're optimistic, but also cautious that there's a lot of work that has to be done collectively as an industry to see the type of scale that we've been seeing in headlines about this," he says.

A takeover, or a new market?

Despite those challenges, commentators largely agree that silicon will become mainstream for space applications in LEO, likely within the next five years.

"I would not have predicted when I first joined aerospace 12 years ago how big the space market would become," says Lao.

However, conditions in deep space are even more extreme than in LEO, making adaptations from silicon an unlikely contender for missions further from Earth. The solar panel for the ESA's Juice mission to collect data from Jupiter's moons was tested for its ability to withstand -230 degrees Celsius to +110 degrees Celsius.

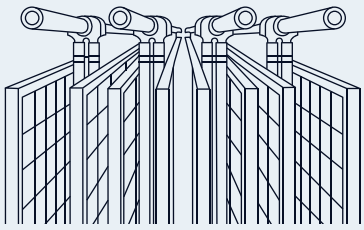
The real story is therefore not silicon replacing III-Vs, but the LEO boom creating a new market that wants cells that are cheaper, faster to procure and made in far greater volumes. Whether that market is met depends on how well terrestrial technologies can be adapted for orbit. ■

Catherine Early is a freelance journalist.

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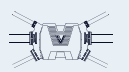
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India's solar sector: scaling capacity, strengthening manufacturing

Policy | India's solar ambitions are accelerating capacity additions, expanding household access and strengthening domestic manufacturing. But infrastructure constraints, financing risks and supply-chain gaps will shape the sector's next phase of growth, writes Shreeyashi Ojha



Credit: Kushagra Dhall

India's energy landscape is undergoing a major transition, with solar power playing an increasingly central role in capacity expansion and energy security. Total installed power capacity reached around 552GW in July 2026, including 300.50GW of non-fossil capacity.

Solar capacity has climbed to 164.59GW, up from 2.8GW in 2014, driven by utility-scale projects and with supportive residential initiatives such as PM Surya Ghar: Muft Bijli Yojana (PMSGMBY), a programme to install rooftop solar PV on ten million households in India.

Yet sustaining this momentum will require more than adding capacity. Transmission bottlenecks, storage requirements, financing challenges and gaps in domestic manufacturing remain significant hurdles.

As India pursues its 2030 ambitions—anchored by a target of 500GW of non-fossil capacity, a massive acceleration in solar power and a projected 208GWh requirement for battery energy storage systems (BESS)—the challenge is to translate rapid expansion into reliable projects, accessible clean energy and a competitive, resilient domestic solar industry.

India's installed solar PV capacity has increased from 2.8GW in 2014 to over 164GW today

Utility-scale solar: India's growth ambitions meet the realities of delivery

India's utility-scale solar capacity stands at 125.65GW, forming the backbone of its renewable energy expansion. By region,

Rajasthan leads with 42.17GW, followed by Gujarat (32.30GW), Maharashtra (20.27GW), Tamil Nadu (13.90GW) and Karnataka (11.34GW). As deployment accelerates, the focus is shifting from tender awards to execution, with transmission constraints, domestic cell supply, financing costs and storage needs arising as key challenges.

For Prabhakar Sharma, senior consultant at JMK Research, transmission infrastructure and domestic manufacturing capacity are among the most pressing challenges. India's push to use domestically manufactured solar cells in eligible projects is intended to strengthen the local supply chain, but manufacturing capacity has yet to catch up with demand.

"The manufacturing capacity of cells in India is [far less than needed]," Sharma says, noting that establishing new facilities requires significant investment and time. Based on discussions with manufacturers, he estimates that setting up a cell factory can take at least two years, with substantial capital expenditure and technical complexity adding to the challenge.

India's domestic manufacturing requirements could therefore create a mismatch between project timelines and equipment availability. Although the government has extended its Approved List of Models and Manufacturers (ALMM) List-II requirements for certain projects, Sharma says uncertainty remains over how new projects will be affected.

The implications could extend across the project development cycle, from bidding to installation and commissioning. Sharma points to the potential combination of higher module prices and limited supply as a concern, particularly until domestic cell manufacturing expands sufficiently to meet annual demand. He says that without further extensions or regulatory flexibility, "then definitely the pace will slow down". India's domestic PV manufacturing supply chain will be explored in greater depth later in this article.

From capacity additions to round-the-clock renewables

Supply chain constraints are only one part of the picture. The scale and composition of India's project pipeline are also evolving as the sector moves towards renewable energy backed by storage.

Harshul Kanwar, research analyst for solar and storage in APAC at Wood Mackenzie, points to a change in tendering and commissioning trends. While the government has set an annual renewable energy tendering target of 50GW, tender volumes have declined over the past year, even as projects awarded in 2023 and 2024 have moved towards commissioning.

At the same time, grid curtailment and the need for storage are becoming more prominent in project planning. Kanwar highlights the increase in battery installations, which he says rose from 0.8GWh installed as of 2025 to 10GWh within six months. He also points to a battery storage project pipeline exceeding 140GWh under construction, illustrating the growing scale of investment in flexibility.

For Kanwar, the shift towards storage-backed generation marks an important development in how India approaches renewable energy procurement.

"The intent of the government to pair [solar] with high [levels of] storage and look at this from a firm and dispatchable point of view, not just plain vanilla solar projects, is a very good intent," he says.

The direction of travel is increasingly towards hybrid projects that combine solar with battery storage and, in some cases, wind power. Such configurations can help address the variability of solar generation and provide electricity at times when demand cannot be met by solar alone.

"Solar coupled with storage is going to be the future," Kanwar says, pointing to the role hybrid projects are likely to play in the coming years.

However, it should be noted that their deployment introduces additional considerations around project costs, system design and the commercial structures needed to support investment.

Corporate PPAs broaden the demand base

Alongside government-led tenders, corporate procurement is creating another avenue for utility-scale solar development in India. Ankita Chauhan, director at market analysts Wood Mackenzie, says demand is growing among energy-intensive industries, including metals, mining and manufacturing and emerging sectors such as data centres.

This demand extends beyond standalone solar to include hybrid renewable energy projects combining solar, wind and storage. Corporate buyers are also exploring different procurement structures, including direct and virtual power purchase agreements (PPAs), broadening the potential market for developers.

"There is an increasingly growing segment of corporate PPAs, which will create demand for solar and not just solar, but hybrid solar plus wind plus energy storage projects," Chauhan says.

However, converting this demand into commissioned capacity will require action from both central and state governments. Chauhan highlights the need to address regulatory barriers affecting open-access projects, arguing that policy and market structures must allow projects to progress without unnecessary obstacles.

"The role of the government, not just federal, but also state governments, is to make sure that the hurdles [and] regulatory barriers which are there for open access projects are removed," she says.

Renewable consumption obligations could stimulate further for demand, particularly as penalties are introduced to encourage compliance. Yet the economics of procurement remain uncertain. The transition towards domestic modules is expected to increase capital expenditure for some projects, potentially pushing tariffs higher.

"The cost of the capex is going to increase, and that would have to translate in your tariffs," Chauhan says.

The question, she adds, is whether buyers will be willing to accept those higher tariffs. The answer will influence how quickly the growing demand for renewable electricity translates into new project commitments.

Bankability remains central to deployment

For Gaurav Upadhyay, lead energy finance specialist for India's Just Transition at the Institute for Energy Economics and Financial Analysis (IEEFA), the challenge is increasingly about execution rather than the availability of technology or project development expertise.

"India has done very well on utility-scale solar, and we now have a fairly mature project development and financing ecosystem," Upadhyay says. However, meeting the country's 2030 ambitions will require deployment to remain at a high level and potentially accelerate further.

The critical steps lie between a project being awarded and becoming operational. Developers must secure PPAs, obtain transmission connectivity and reach financial close. Delays at any of these stages can slow commissioning, even where projects have been competitively bid.

Upadhyay identifies land availability, transmission constraints, delays in signing PPAs and the financial health of distribution companies (DISCOMs) as persistent obstacles. From a financing perspective, he places particular emphasis on offtake and counterparty risk.

"A project may have very competitive tariffs, but if the payment security or PPA arrangements are uncertain, it becomes much harder to raise affordable finance," he says.

This makes project bankability as important as the pace of capacity additions. Developers and lenders need confidence that contracted electricity will be purchased and payments made reliably. Without that assurance, low tariffs alone may not be sufficient to secure financing on favourable terms.

"So, improving the bankability of projects is just as important as adding capacity," Upadhyay says.

Rooftop solar: from subsidy-led growth to a sustainable market

While utility-scale solar faces challenges around transmission, project execution and storage, India's rooftop solar market is gaining momentum, with cumulative grid-connected capacity reaching 33.41GW as of September 2026, according to the Ministry of New and Renewable Energy (MNRE).

Residential solar installations are gaining momentum, driven by government subsidies and growing consumer awareness of the benefits of rooftop solar. The challenge now is to sustain this growth through reliable system performance, accessible financing and long-term savings.

JMK's Sharma says residential solar has grown rapidly since the launch of PMSGMBY, bringing households closer to the centre of India's rooftop market. "Earlier, it used to be only the industries and commercial entities setting up solar on rooftops. Now the home segment is the dominant segment, or just about there," he says.

PMSGMBY was launched in 2024 by the government of India to accelerate rooftop solar adoption among residential households. The scheme aims to provide free electricity of up to 300 units per month through rooftop solar installations, supported by government subsidies to reduce household electricity costs and promote clean energy.

Government support has helped accelerate adoption, but Sharma believes the underlying economics will continue to attract households. Savings on electricity bills remain a key incentive, while inverters, hybrid systems and small batteries can help households use solar power when grid supply is unavailable.

System performance under scrutiny

As installations rise, Sharma warns that quality and system performance need greater attention. Poor-quality equipment, inadequate installation and insufficient maintenance can undermine generation, affecting consumers, vendors and the wider sector.

"You can set up a 1kW system, but if your system is not performing well, then ultimately it's the loss of subsidy, it's the loss of the capex that is felt by the consumer," he says.

He argues that future policy should place greater emphasis on how well systems perform, rather than focusing primarily on installed capacity. "If the government comes up with a plan of aligning the subsidy with the performance rather than the capacity installation, that will be a major, major step," Sharma says. He also highlights the need for national monitoring of residential systems to track generation and identify underperforming installations.

Subsidies drive adoption, but for how long?

For Chauhan, subsidies remain central to the current growth trajectory. She estimates that government support covers around 40% of residential rooftop solar capital expenditure, making installations more affordable for households. State-level initiatives and efforts to accelerate approvals have also contributed to deployment.

Kanwar points to the pace of recent installations as evidence of the market's acceleration. He notes that approximately 7GW was installed in the previous year, with a comparable amount reportedly added in the first six months of the current year. Anticipated module price increases and the approaching subsidy deadline may be encouraging households to install systems sooner.

"The process has smoothed out," Kanwar says, referring to the consumer experience compared with earlier rooftop solar programmes. However, the extent to which current growth reflects lasting demand remains an important question.

Building a market beyond subsidies

IEEFA'S Upadhayay believes the market has reached a meaningful turning point. "PMSGMBY has helped create awareness, reduce the upfront cost for households and make the payback economics much more attractive," he says.

Bridging the gap between tenders and projects

India's ambitious target of awarding 50GW of renewable energy tenders annually has created a substantial project pipeline, but awarded capacity does not automatically translate into projects under construction. The gap reflects challenges in power procurement, transmission infrastructure and domestic manufacturing.

Sharma explains that buyer preferences are shifting away from standalone solar towards round-the-clock and dispatchable renewable power. "They want power in the nighttime and the periods when solar is not available," he points out, noting that buyers are increasingly seeking battery storage and more complex contracts. Expectations of falling solar tariffs can also delay power purchase agreements, while transmission connectivity remains a significant bottleneck, with some developers facing waiting periods of several years.

Meanwhile, India's push for domestic manufacturing presents both opportunities and constraints. Chauhan highlights potential supply-chain pressures as domestic content requirements expand from modules to cells and, eventually, wafers. Targeted exemptions could help keep projects on schedule.

Despite these hurdles, the outlook remains positive. Kanwar notes there are more than 150GW of utility-scale renewable energy projects in the pipeline, including over 100GW of solar. He argues that annual installations of 50GW remain achievable if the government addresses bottlenecks and strengthens domestic manufacturing.



Credit: Premier Energies

Subsidies will remain important, particularly for households facing longer payback periods. But Upadhyay argues that the priority should be to build a market that can sustain itself beyond short-term policy incentives.

That will require more accessible consumer finance, longer-tenure loans and greater participation from banks and non-banking financial companies (NBFCs). Upadhyay also points to renewable energy service company (RESCO) and operating expenditure (opex) models, which can allow households to adopt solar without bearing the full upfront investment.

"The objective should be to combine policy support with a stronger financing ecosystem so that rooftop solar remains attractive based on its lifetime economics and not only because of the subsidy," he says.

India's residential rooftop market has gained considerable momentum, but sustaining it will require a shift in focus. Subsidies can help households make the initial move to solar; reliable installations, measurable generation, accessible financing and long-term savings will determine whether they stay invested in it.

Government manufacturing incentives should be gradually phased out to protect Indian manufacturers

Building a domestic PV manufacturing industry beyond module assembly

India's solar manufacturing sector has expanded rapidly, driven by government incentives, domestic-content requirements and rising renewable energy demand.

Sharma notes that India has advanced faster than many industry participants expected following the introduction of the Production Linked Incentive (PLI) scheme. While module manufacturing has grown significantly, the challenge is to extend capacity across the value chain, from polysilicon and wafers to cells and finished modules.

Amit Manohar, secretary general of the Indian Solar Manufacturers Association (ISMA), highlights the growth in module and cell manufacturing and rising investment in wafers and ingots. He sees vertical integration as essential to improving cost control and supply-chain security.

The uneven progression from modules to polysilicon

Nonetheless, India's manufacturing growth remains uneven, with module assembly significantly ahead of upstream production.

Wood Mackenzie's Ankita Chauhan attributes this imbalance to lower barriers to entry in module assembly. Producing cells, wafers and polysilicon requires greater capital investment and technical expertise, leaving gaps across the domestic supply chain.

Chauhan also highlights India's reliance on technologies commercialised elsewhere, particularly in China. While technology transfers have supported expansion, limited domestic research and development (R&D) could constrain independent innovation.

Manohar points to growing interest in wafer and ingot manufacturing, but Sharma notes that polysilicon production remains particularly challenging due to its capital requirements and dependence on overseas minerals and industrial inputs.

The technology gap: scale without sufficient R&D

India's ability to keep pace with global innovation remains a concern. Chauhan notes that manufacturers have largely adopted established international

"The objective should be to combine policy support with a stronger financing ecosystem so that rooftop solar remains attractive based on its lifetime economics and not only because of the subsidy"

technologies rather than developing their own, risking a continued technology gap with China.

The transition from PERC (passivated emitter and rear cell) to TOPCon (tunnel oxide passivated contact) cell technology illustrates the need for continued investment. Adopting heterojunction and back-contact technologies will require further equipment upgrades and technical expertise.

Manohar offers a more positive assessment, pointing to the growing presence of TOPCon alongside PERC, thin-film and other technologies. However, sustained competitiveness will require manufacturers to upgrade production lines while strengthening domestic R&D.

ALMM and PLI: Balancing protection with industry readiness

The PLI scheme has encouraged manufacturing investment, while the ALMM framework has supported demand for domestic products. However, cell manufacturing has struggled to keep pace with module production.

Chauhan questions whether manufacturers had sufficient time to establish the capacity needed to meet newer requirements, while acknowledging that demand certainty is essential to investment.

Kanwar notes that PLI investment was concentrated on modules because barriers to entry were lower. He argued that localisation policies are necessary to encourage investment further upstream.

Manohar describes ALMM as a means of providing predictable demand and encouraging backward integration. Sharma, however, cautioned against withdrawing protection too quickly, advocating a phased transition towards international competitiveness.

The challenge is to strengthen domestic manufacturing without creating supply constraints or increasing costs for project developers.

Manohar identifies scale, competitive financing, affordable electricity and reliable feedstock as key factors in narrowing the gap. Sharma advocates gradually reducing protection as domestic manufacturers become more competitive.

Meanwhile, Chauhan notes that Indian modules can remain substantially more expensive than Chinese products, limiting access to price-sensitive export markets. Closing the gap will require greater efficiency, consistent product quality and reliable delivery.

Polysilicon: the missing link in self-reliance

Polysilicon production remains a major obstacle to building a fully integrated domestic industry. Recently, the government of India announced plans for a PLI scheme to support domestic polysilicon manufacturing, potentially covering more than 10GW of production capacity, as it seeks to reduce import dependence and build an integrated solar PV supply chain.

Talking about polysilicon production, Manohar points to competitive capital, affordable power and dependable feedstock as essential to commercial viability. Initial government support could help facilities improve yields and reach scale.

Sharma calls for polysilicon development to be integrated with India's National Critical Minerals Mission, highlighting the need to secure minerals and industrial inputs.

Chauhan and Kanwar are more cautious, noting that announced plans have yet to produce a substantial manufacturing base. Reducing import dependence will require investment in technology, financing and raw-material supply. They agree that the goal should be greater supply-chain resilience rather than complete insulation from international markets.

Module overcapacity and the search for new markets

India's expanding module capacity has raised concerns about whether demand can absorb future production.

A joint report by IEEFA and JMK, published in September, found that India's solar module manufacturing capacity had reached approximately 233GW, with factories operating at just 35–40% utilisation. It estimated that a further 135GW of capacity was in the pipeline, raising concerns about overcapacity as manufacturing expansion outpaced demand.

However, Chauhan argues that headline capacity can be misleading, given low utilisation rates, older PERC technology and changing product requirements. US trade restrictions and investigations have also encouraged manufacturers to focus on domestic demand.

Manohar views the industry as ahead of the domestic demand curve rather than fundamentally overcapacity. He highlights potential growth from solar-plus-storage projects, green hydrogen and data centres.

He also stresses the need to diversify exports towards Europe, the Middle East, Southeast Asia and Africa. However, Chauhan cautions that Chinese manufacturers' established positions and lower prices could limit India's gains. Export diversification must therefore be supported by stronger cost competitiveness.

Policy certainty and the road ahead

India has made considerable progress in solar manufacturing. Its next test is to build an industry that is technologically capable, cost-competitive and resilient to global supply-chain disruptions. That will determine whether it becomes a major global manufacturing hub or remains primarily a module assembly market.

India's next manufacturing phase must prioritise commercially sustainable production alongside capacity expansion. Manohar stressed the importance of scale and stable policies, particularly for capital-intensive upstream investments.

Sharma's call for a gradual easing of protection and Chauhan's emphasis on technological development underline the need to move beyond capacity creation alone. ■

Data centres are Australia's next big solar and storage customer, and the rulebook is still being written

Data centres | George Heynes explores how Australia's push to make large data centres net generators of renewable energy is splitting the states, and what the rules, demand forecasts and firming requirements mean for solar and storage developers, regulators and grid operators



Credit: FRV Australia

FRV Australia's Walla Walla project is supplying Microsoft under a 15-year PPA

When Australia's prime minister Anthony Albanese announced on 15 July that large-scale data centres would be legally required to become "net-generators, not net-users", the aim was clear.

Facilities that draw power from the grid would have to put back at least as much renewable energy as they take, on top of any renewable energy capacity already being built. Turning that into law is proving harder; the policy has since been endorsed by most energy ministers and extended by at least one state, but rejected by two jurisdictions.

Albanese said the government would create a legal obligation for large data centres to underwrite a new power supply. They would also pay their full share of grid connection costs, with nothing passed on to households or businesses, and cut their power use when the grid is under strain. The obligation includes firming, which could give battery storage a route to count towards compliance.

For solar developers and storage suppliers, the stakes are practical. If the obligation is written as intended, it could change who signs off-take agreements, how large those projects are and how much battery storage capacity is built alongside them.

No numeric definition of "large-scale" has been published, and the announcement created an Office of AI within the Department of the Prime Minister and Cabinet to design the standards. Albanese planned to seek National Cabinet agreement in August and to introduce legislation in early 2027, although the outcome of the August meeting was not available at the time of writing.

The Commonwealth sets the floor, the states test the ceiling

The first test came on 28 July, when the Energy and Climate Change Ministerial Council (ECMC), which brings together federal and state energy ministers, agreed to progress nationally consistent rules. The Commonwealth would legislate the standards while states and territories stay free to add stricter local requirements.

Data centres would have to offset their demand with new renewable energy generation in the same jurisdiction, with an opt-out for jurisdictions too small to host their own. Rule change requests were due to go to the ECMC in September to treat data centres in the National Electricity Market (NEM) as market participants that must demonstrate they can offset demand with new renewables, adequate firming and demand flexibility.

The agreement was not unanimous. Queensland and the Northern Territory opposed the framework at every substantive vote, while the other six jurisdictions backed it; their reasons were not reported in the meeting's reports. The Climate Council, a community-funded research body, said opposition was out of step with public opinion, citing polling showing that 82% of Australians agreed that governments should require new data centres to pay for additional renewable energy and storage to match their consumption.

Climate change and energy minister Chris Bowen took the dissent head-on at the National Press Club in August, saying states can add stricter requirements but cannot weaken the federal minimum.

The government would use its powers over the Australian Energy Market Operator (AEMO) and the Australian Energy Market Commission (AEMC) to require new data centres to connect only on terms consistent with the national framework. Bowen put the national data centre pipeline at AU$150 billion (US$99 billion), which goes some way to explaining why the Commonwealth is unwilling to leave the terms to individual states.

Some states are already moving past the floor. On 22 September, Victoria released rules requiring new data centres to supply their own renewable energy and battery storage, to match new demand with new generation, and to pay their own connection costs.

Planning minister Sonya Kilkenny said: "Data centres must bring their own supply to protect our energy costs, and they cannot be built near homes."

New South Wales has taken a third route, with a bill that gives the energy minister renewable energy zone-style powers over large-load grid access for facilities capable of drawing 5MW or more.

Western Australia sits outside the NEM, and because the ECMC rule changes target NEM participants, it is not clear how the framework would apply there.

The effect is a national floor with a patchwork above it, and until the legislation is drafted, projects in Victoria, New South Wales and Queensland may face different tests for what counts as new, local and firm.

Regulators and untrusted demand figures

Alongside the offset obligation sits a stack of technical rule changes. The AEMC released a draft rule in March that would require large data centres to remain connected during voltage and frequency disturbances, replacing the current 5MW threshold with three tiers and automatically applying the access standards to loads of 100MW or more.

AEMC chair Anna Collyer has previously publicly said: "Data centres aren't passive loads anymore; they're active grid participants", and the commission points to a July 2024 incident in Virginia in which 60 data centres pulled 1,500MW off the grid during a single fault.

AEMO has since lodged its own rule change request on grid-supportive behaviour, covering fault ride-through and ramping. A final AEMC rule was expected in mid-2026, but its current status has not been confirmed.

However, on cost, AEMC commissioner Lana Stockman tells *PV Tech Power* that "the starting point for the AEMC is simple: consumers cannot be left worse off".

The commission has advised ministers to consider two reform streams: one requiring data centres to fully offset their demand by bringing forward new renewables and securing firm capacity through contracts, storage or demand flexibility; and the other reviewing who bears network costs if expected demand does not materialise.

She is also wary of the headline demand numbers. "A connection queue is not a demand forecast," she says, citing AEMO analysis that actual demand can sit well below installed or contracted capacity because facilities take years to ramp up.

Carly Wishart, managing director for corporate and international at data centre operator AirTrunk, goes further, and has previously said that more than 85% of Australian data centre energy applications are considered "phantom demand".

What solar and storage can offer

Whatever the true demand figure, the offset obligation translates into capacity that has to be built. Wishart estimates that each additional gigawatt of data centre demand needs around 3GW to 4GW of new renewable energy capacity to support round-the-clock operation.

Operators are already signing deals to

"There are a lot of unused electrons sitting in the Australian grid in the form of curtailed energy. Battery storage is a great way to absorb those electrons and reapply them into the data centre"

this end: Amazon is committing around US$13.9 billion to expand its Australian data centres, backed by utility-scale solar PV; and Microsoft signed a 15-year power purchase agreement (PPA) with FRV Australia for a 353MW solar plant in New South Wales in 2025.

Battery integrator Fluence sees storage as the piece that connects the policy threads. Jeff Monday, the company's senior vice president and chief growth officer, divides the opportunity into three use cases.

The first is load smoothing. AI workloads draw power in ways that are hard for grid operators to manage in real time, and Monday says a Fluence SmartStack battery energy storage system (BESS) "can act as basically a shock absorber between the data centre and whatever the generation asset is".

The second is cold-start backup, which replaces diesel generators to help hyperscalers meet carbon-neutral commitments made before the AI surge.

"Now they're in this interesting place where they're still needing to meet their carbon neutral goals while also bringing a lot more power consumption," Monday says.

The third, which he describes as potentially Fluence's largest application globally, is speed-to-power. In the US, he says, a 100MW data centre filled with GPUs but waiting for a grid connection loses about US$100 million in revenue a month, and co-locating batteries as peak-shaving assets has cut a three-year interconnection wait to 15 months. Both are US figures supplied by Fluence, and no Australian equivalents were given.

Sam Markham, the company's senior manager for policy and strategy in Australia, argues the logic carries over to Sydney.

"We don't have interconnection queues in the same way, but for Sydney, we're just out of transmission infrastructure right now, and the Sydney Ring isn't built until 2032 or 2033, and that's just too long," she says.

"You can get more out of your existing transmission infrastructure by using a data centre to do that peak shaving."

Fluence calls the common thread a "ratepayer shield". "Batteries are unique. They can act as both a transmission and a generation asset," Monday says.

"That agility allows us to address the key needs of the data centre while also protecting consumers through the grid resiliency that we're driving."

He also points to the supply already in the grid. "There are a lot of unused electrons sitting in the Australian grid in the form of curtailed energy. Battery storage is a great way to absorb those electrons and reapply them into the data centre," he says.

Markham extends the argument to ancillary services. If data centres exhibit grid-supportive behaviour under clearly defined requirements, AEMO gains a clearer real-time view of changing demand, which could reduce the frequency control ancillary services it needs to hold in reserve.

"That's just one market and one example, but it has so many downstream consequences," she says. Monday adds that Fluence's SmartStack has been integrated into Siemens and NVIDIA's AI data centre reference architecture.

He expects battery duration to rise from 2-4 hours over time. He urges developers to model returns over ten years, because power-smoothing demand may fall as chips and software improve, freeing capacity to trade back into the grid.

Where industry and academics draw the line

Both Fluence and AirTrunk back the policy direction, but each attaches conditions. Markham worries about the complexities of a patchwork legislation.

"We've got the NEM implementation now. We've got new directives coming from ECMC, and it's at risk of creating a really complicated patchwork for what is ultimately a government commitment to decarbonise by a certain date," she says. On the offset rule, she wants it to bring new capacity.

"I'm really concerned about making sure that any requirements are focusing on firm renewables, not just renewables in isolation," she says, since a data centre that buys certificates from existing solar farms could meet a renewability test while adding no new generation.

AirTrunk's concern is commercial. Sabooh Whitelaw, its associate vice-president for energy and utilities, states that "Australia needs to build at an unprecedented scale", and sees data centres as anchor tenants for new generation, storage and transmission.

"We, the data centres, are the demand looking for energy infrastructure," she says. But there are limits.

"Long-term data centre demand is very valuable to energy projects. It is not a blank cheque," she says, adding that "strong demand cannot compensate for poor project economics".

Researchers at the University of New South Wales (UNSW) focus on enforcement and where the capacity is built. Greg Leslie, director of the UNSW Global Water Institute, says the Commonwealth's proposed regulations are "a welcome and necessary first step", but state and local governments must embed the requirements in planning approvals and operational oversight.

"It is at that level that we must ensure data centres pay their fair share of infrastructure costs," he adds. He argues that "export-scale facilities" must be "built on new, clean energy and help expand the system, rather than relying on an already stretched grid".

Markham closes on coherence, not on any single rule. "We've got a fracturing already happening, looking at connections as discrete from operations, discrete from the bring-your-own renewables requirement, and they are all interrelated," she says.

For developers, the open questions include the size threshold for "large-scale", whether compliance is measured annually or hourly, how the "new" generation is verified, what counts as firming and whether Queensland and the Northern Territory comply or are overridden. The next signals will be the rule change requests, the AEMC's final standards and the legislation targeted for early 2027. ■

China's soaring clean power curtailment highlights regulatory gaps

Policy | In the first half of 2026, China rejected enough solar and wind power to supply Mexico for a year. Carrie Xiao looks at what is being done to tackle the country's escalating curtailment problem



Credit: chungking, Adobe Stock

Under China's plans to achieve carbon neutrality by 2060, PV and wind power have become indispensable pillars of its new energy mix. As of the end of July 2026, China's installed PV capacity had reached 1,286GW, surpassing coal power for the first time to become the country's largest power source by installed capacity.

Despite the rapid expansion of PV installations, curtailment challenges have become prominent in certain regions, bringing renewable curtailment rates back into the spotlight.

A joint monitoring report by two international non-profit energy organisations—the Centre for Research on Energy and Clean Air (CREA) and Global Energy Monitor (GEM)—shows that in H1 2026, China's combined wind and PV curtailment—where solar or wind power is pre-emptively rejected due to grid incapacity—reached 360 billion kWh, up 49% year-on-year.

In addition to third-party agencies, recent corporate reports from power utilities also corroborate the wind and PV curtailment problem.

CECEP Wind-Power Corporation, a listed subsidiary of China Energy Conservation and Environmental Protection Group, disclosed in its 2026 semi-annual report that from January to June, the company lost a total of 1,506,870,000kWh to wind curtailment and output restrictions. The group-wide wind curtailment rate stood at 20.84%.

Curtailment of PV and wind power in China has become a critical issue, requiring a coordinated regulatory response

Table 1 below shows the company's indirect generation losses due to wind curtailment and output restrictions from 2024 to 30 June 2026.

Meanwhile, H1 2026 filings from other central state-owned power generators show sharp profit declines, epitomised by the paradox of "generating more yet earning less". Based on disclosed H1 2026 performance figures, China Three Gorges Renewables projected a net profit attributable to shareholders of the parent company of RMB1.045 billion to RMB 1.295 billion (US$155.6 million to US$192

million), down 66-73% year-on-year; Datang Renewable Power's net profit fell 58-60%; CGN New Energy posted a 49.8% year-on-year decline; GD Power Development reported a 67.3% drop in first-half net profit, with its PV segment's net profit plunging 62.94%.

Notably, official H1 2026 statistics put the national wind curtailment rate at 9.1% and the PV curtailment rate at 8.6%. Both corporate-reported figures and estimates from overseas research institutions are higher than the official figures.

Experts attribute the sizable gap between CREA/GEM estimates and official statistics to differing calculation methodologies. Official curtailment and utilisation rates are calculated from data reported by grid-connected power plants and serve as the benchmark for policy-making. By contrast, research bodies such as GEM and CREA use weather-based models to estimate potential generation.

Regardless of the methodology, all datasets indicate rising wind and PV curtailment rates. It has become imperative to systematically and comprehensively boost renewable energy consumption.

Specific distribution of wind and PV curtailment

Data released by the National Energy Administration (NEA) show that in H1 2026, the national wind power utilisation rate stood at 90.9%, and the PV utilisation rate at 91.4%, down 2.3 and 2.6 percentage points year-on-year, respectively. These rates have fallen for three consecutive years. Apart from these national averages, several major provinces with large-scale PV capacity recorded utilisation rates below the national average (see Table 1).

According to data from the Power Industry Planning Research and Monitoring and Early Warning Center under the China Electric Power Planning & Engineering Institute (EPPEI), provinces with PV utilisation rates below 91% in Q1 2026 included Shaanxi (89.8%), Gansu (82.5%), Qinghai (76.8%), Ningxia (89.5%), Xinjiang (83.2%), Tibet (63.8%), Hainan (86.5%) and Yunnan (84.8%).

From a regional perspective, provinces with relatively low PV utilisation rates are concentrated mainly in northwest and southwest China—regions that have seen rapid roll-out of utility-scale PV projects, including Qinghai, Gansu, Yunnan and Xinjiang. Compared with provinces suffering from insufficient consumption capacity, these regions host a large installed base of PV capacity. This indirectly points to substantial volumes of wind and PV curtailment across these provinces.

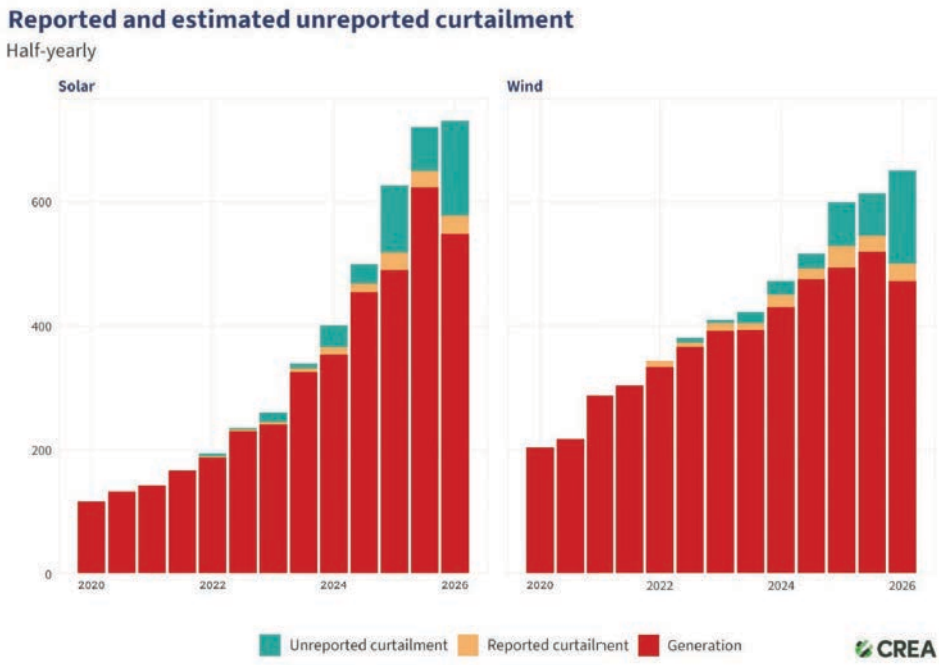


Figure 1. Reported and estimated unreported wind and solar curtailment in China in H1 2026. Source: CREA

According to disclosures from CECEP Wind-Power Corporation, its wind farms in Qinghai recorded nearly 150 million kWh in curtailed electricity during H1 this year. The curtailment rate reached 29.45%.

Qinghai's disproportionately large new-energy installed base has driven high curtailment rates and low power prices. Figures released by the NEA show that as of end-June 2026, Qinghai's cumulative new energy installation stood at 63.1702GW, accounting for 74.06% of the province's total power-generation capacity. Within this total, wind power installation has surpassed 16GW.

In addition, Lambda spot-market data indicates that since January 2025, actual grid-dispatched PV output in major new-energy provinces participating in the spot market has generally been lower than forecast, marked by notable PV curtailment and output constraints. The data shows that the ratio of actual to forecast PV generation generally hovers

Table 1. CECEP Wind-Power Corporation disclosed province-level curtailment figures in its semi-annual report. Source: company filings

Unit: 10,000 kWh

Region	Jan-Jun 2026		2025		2024	
	Electricity Loss	Share	Electricity Loss	Share	Electricity Loss	Share
Hebei	17225	15.42%	28602	13.04%	18054	9.20%
Gansu	34640	23.08%	63391	22.01%	44535	16.89%
Xinjiang	51312	41.10%	83039	35.78%	43460	18.31%
Inner Mongolia	9997	17.31%	15852	13.64%	10094	10.56%
Qinghai	14989	29.45%	22698	24.49%	14022	14.57%
Hubei	4821	12.68%	11951	13.53%	3352	4.96%
Henan	3367	11.19%	4174	6.37%	3324	6.00%
Shanxi	1892	6.85%	2254	3.51%	986	1.91%
Shandong	2382	14.94%	1260	4.13%	224	0.84%
Shaanxi	1476	21.25%	1339	9.94%	0	0.00%
Sichuan	60	0.23%	0	0.00%	0	0.00%
Guangxi	7478	14.83%	16599	15.30%	2895	3.24%
Guangdong	1048	3.20%	1075	1.40%	25	0.03%
Total	150687	20.84%	252234	17.41%	140970	10.33%

around 70% and has never exceeded 80%. In certain provinces such as Shandong, this ratio can drop to nearly 66% in low-output months—equivalent to a curtailment rate of close to 40%.

Grid bottlenecks

Why is the PV consumption dilemma growing more severe? The first and unavoidable reason is that capacity additions have outpaced grid build-out.

As is widely recognised, intermittency and volatility are inherent characteristics of PV generation, which are not problematic in themselves. The real bottleneck lies in grid construction failing to keep pace with the rapid expansion of PV installations.

The joint report by CREA and GEM explicitly identifies inadequate grid development—unable to keep pace with green energy capacity growth—as the leading cause of large-scale renewable curtailment in China.

The northwest region serves as the country's core hub for new energy development under the "sand, gobi and desert" initiative, an effort to build new renewable energy capacity in regions with significant solar and wind potential and abundant land, such as Xinjiang and Inner Mongolia. While large-scale base projects under the initiative continue to advance, the region is constrained by the delayed construction of outbound transmission corridors and insufficient local power demand. Consequently, surplus renewable power cannot be fully consumed or exported in a timely manner.

Experts from State Grid Corporation of China highlight two dimensions of curtailment patterns. Spatially, curtailment remains concentrated in the Three-North Region, which includes northern, northwestern and northeastern China. By 2030, curtailed power within this region is projected to account for roughly 80% of total curtailment across State Grid's service territory. Temporally, spring and autumn curtailment accounts for 74% of annual curtailment, while mid-day curtailment represents 74% of daily curtailment.

Sharp supply-demand mismatches in system flexibility and regulation capacity, coupled with strains on multi-level grid configuration capability, constitute the core bottlenecks holding back renewable consumption today. Retrofit potential for flexible-operation upgrades on conventional thermal power units is shrinking. Pumped-storage projects feature long construction lead times, while new energy storage capacity still suffers from weak economics at the current stage. Wide-range optimal resource allocation via large-scale grids also faces hurdles such as scarce transmission corridor resources and steeply rising construction complexity.

Beyond grid-infrastructure constraints, electricity prices represent another critical challenge weighing on renewable energy consumption.

Following the implementation of Document No. 136, which promotes full market participation of renewable energy, PV projects have lost fixed feed-in tariff (FIT) protection. With spot market prices remaining relatively low—compounded by consumption constraints in certain regions—project returns are under sustained pressure.

According to May electricity market data released by State Grid Shandong Electric Power Company, the reference settlement price under the PV pricing mechanism stood at a mere RMB51.042/MWh. This translates to approximately RMB0.051/kWh—less than RMB 0.1.

Statistics from the NEA show that nationwide newly installed decentralised PV capacity tumbled 60% year-on-year in H1 2026, with Shandong alone recording an 84% drop. Installed capacity for C&I decentralised PV fell by over 61% year-on-year. For certain decentralised PV projects, January on-grid tariffs ranged from RMB0.013/kWh to RMB0.3232/kWh, representing a drop of up to 97% compared with the local coal-fired benchmark on-grid tariff.

Depressed electricity prices, compounded by steep declines in grid-connected electricity volumes due to curtailment, have systematically undermined the revenue models of existing power plants. Some generators saw their PV on-grid volumes plunge by as much as 36.74% in Q1. This partly explains the widespread profit downturn across power generation firms.

Caught between electricity that cannot be dispatched and power that cannot fetch viable prices, China's PV plants are trapped in a predicament.

Region	Wind Utilisation Rate	PV Utilisation Rate
Tibet	67.1%	63.8%
Qinghai	92.0%	76.8%
Gansu	90.8%	82.5%
Xinjiang	88.0%	83.2%
Yunnan	91.5%	84.8%
Hainan	86.5%	86.5%
West Inner Mongolia	85.0%	90.8%
Shaanxi	94.5%	89.8%
Ningxia	90.5%	89.5%
Hebei	87.7%	90.0%

Table 2. Provinces with low PV utilisation rates, Q1 2026. Data source: Power Industry Planning Research and Monitoring and Early Warning Center, EPPEI

Solving the consumption dilemma: a systemic roadmap

To address renewable energy consumption challenges during China's 15th Five-Year Plan period (2026-2030), the 15th Five-Year Plan for the Development of the New Power System, jointly issued in June by the National Development and Reform Commission (NDRC) and the NEA, lays out a systematic roadmap. Centred on coordinated management across power generation, grids, loads and energy storage, the plan marks a strategic shift away from the single-minded pursuit of scaling installed capacity toward system coordination and efficient renewable energy consumption.

First, regarding energy storage, the goal is to transform its role from "playing catch-up" to serving as a stabilising anchor for the power system. The plan sets a target for total new energy storage capacity to reach 300GW by 2030, including roughly 160GW of new capacity added during the 15th Five-Year Plan period.

Key measures include: rational energy storage deployment at large-scale projects in desert areas; adding approximately 80GW of standalone storage resources for peak-shaving and supply guarantee, targeting a 4-hour discharge duration; advancing retrofits for existing storage assets; and exploring applications for grid-forming technologies.

Meanwhile, pumped-storage installed capacity is targeted at 160GW.

Second, regarding the coordination of power generation, grid, load and storage, the approach must shift from "working in isolation" to "coordinated operation". The old model—in which each link was planned in isolation—must be replaced by end-to-end coordination across power generation, grid, load and storage. The demand side should no longer function merely as a passive power consumer but as a flexible resource participating in system regulation. Specific targets include: over 100GW of demand-side peak-shaving capacity; more than 50GW of maximum adjustable capacity from virtual power plants; and leveraging electric vehicles as mobile storage to deliver 50GW of adjustable capacity via vehicle-to-grid (V2G) integration.

Third, regarding market signals, the approach is to leverage them to optimise resource allocation. The overarching goal is to substantially establish a nationwide unified electricity market system. Regional differentiated utilisation-rate targets will guide investment. Authorities will fully roll out the power spot market and refine ancillary-service markets, while putting in place a robust capacity-compensation mechanism to incentivise thermal-power units to provide peak-shaving support for renewable energy generation.

Fourth, regarding power-grid upgrades, the focus is on strengthening both the "arteries"(backbone transmission) and "capillaries" (distribution networks). This means boosting long-distance transmission capacity—targeting west-east electricity transmission capacity above 420GW—alongside upgrading distribution networks to accommodate decentralised energy interconnection. For instance, State Grid is prioritising ultra-high-voltage (UHV) corridors to deliver wind and PV output generated from desert and barren land resources to major load centres across eastern and southern China via high-efficiency long-distance transmission. In addition, Gansu Province already operates multiple UHV transmission lines that deliver Gansu-generated power to Shandong, Sichuan and Zhejiang, accelerating progress for west-east electricity transmission initiatives.

Fifth, regarding model innovation, the focus is on local consumption and "computing-power coordination". New business models—including direct green-power interconnection, smart microgrids and zero-carbon parks—will be vigorously promoted. In parallel, artificial intelligence will be deployed to improve renewable energy generation forecasting and grid-dispatch performance, guiding energy-intensive data centres to increase their uptake of green electricity. ■

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Policy upheaval and manufacturing transformation leaves US inverter market at a crossroads

Inverters | The US inverter market is caught in the midst of global supply chain challenges, policy reform and shifting technological trends. PV Tech Research's Mollie McCorkindale considers the factors affecting the US inverter space and what the future could hold for the industry



Credit: SMA Solar

European inverter companies such as SMA Solar are bolstering their manufacturing operations in the United States through new facilities and partnerships with local companies

The US solar inverter market is experiencing its most dramatic transformation in decades. A confluence of aggressive policy interventions, supply chain restructuring and geopolitical tensions is fundamentally reshaping who manufactures inverters, where they're made and which companies will dominate the US' renewable energy infrastructure for years to come.

For an industry that has long relied on imported equipment, particularly from Chinese manufacturers that control nearly 85% of global inverter capacity, the changes underway represent nothing short of a revolution. But whether this revolution will strengthen or destabilise the US solar sector remains an open question.

The perfect policy storm

The US government has deployed an unprecedented combination of incentives and requirements to reshape the

inverter supply chain. On one side, the Inflation Reduction Act (IRA) offers generous incentives: a base 30% Investment Tax Credit (ITC) for solar projects, with an additional 10% bonus for projects meeting domestic content requirements. On the other, Section 301 tariffs impose duties ranging from 7.5% to 25% on Chinese-manufactured inverters, making imports significantly more expensive.

But the most consequential policy shift came in January 2026 with the implementation of Foreign Entity of Concern (FEOC) restrictions. These rules restrict tax credit eligibility for projects using components from Chinese or other prohibited entities above specified thresholds, thresholds that tighten progressively each year. The message to developers is clear: shift away from Chinese supply chains or forfeit substantial tax benefits.

Then came the decision of the Federal Communications Commission (FCC) to ban the imports of foreign inverters in July 2026. Initially focused on inverters with wireless connectivity, the ban was quickly expanded following input from the Department of War to include any inverters with wired communication capabilities, Ethernet or similar connections that enable remote monitoring, control or data collection. This expansion dramatically broadened the ban's scope, potentially excluding a large portion of the utility-scale market, which primarily relies on wired communications.

The ban introduced two pathways for inverters to qualify as "domestic": meeting the 65% US content threshold under the Buy America Act—a threshold set to rise to 75% in 2029—or qualifying for Section 45X tax credits for domestic production. Critically, the ban applies only to new models not yet certified by the FCC, leaving existing approved models and already installed equipment unaffected, at least for now.

A manufacturing landscape in flux

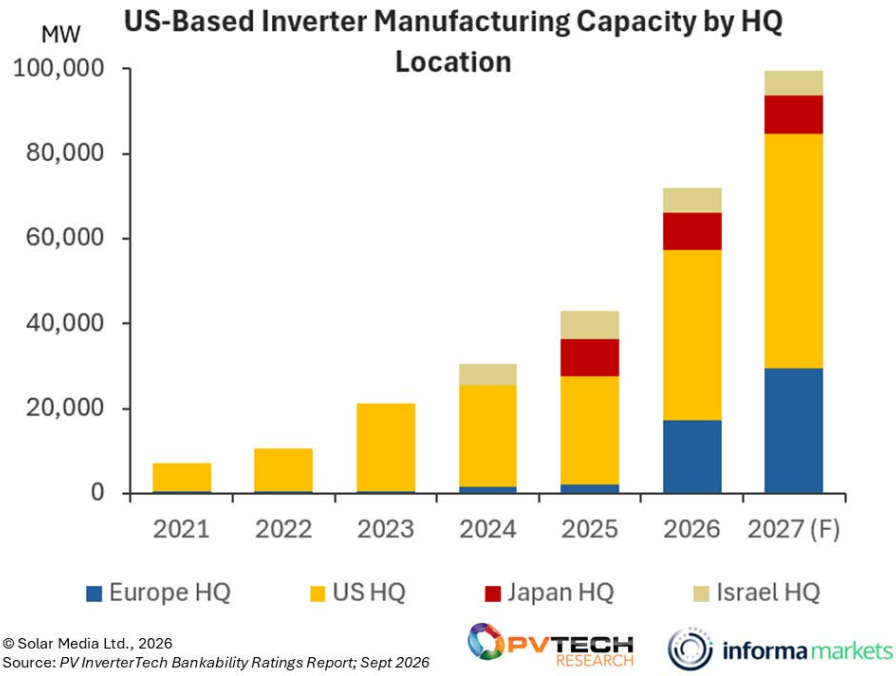
The policy pressure is working. US-based inverter manufacturing capacity has grown dramatically, from around 7GW in 2021 to over five times that in 2025, with forecasts of 70GW by the end of 2026 and 100GW by 2027. But the composition of this capacity tells a surprising story.

US-headquartered companies, which controlled 90% of domestic manufacturing capacity in 2021, are projected to hold 55% by 2027. European manufacturers, meanwhile, have surged from 7% to an anticipated 30% of US capacity over the same period.

Companies such as Germany's SMA Solar, which opened a 3.5GW+ facility in Portland, Oregon in partnership with the US' Create Energy and Spain's Power Electronics are leading this European expansion. The latter is also expecting to scale to 40GW of annual capacity at its Texas facility.

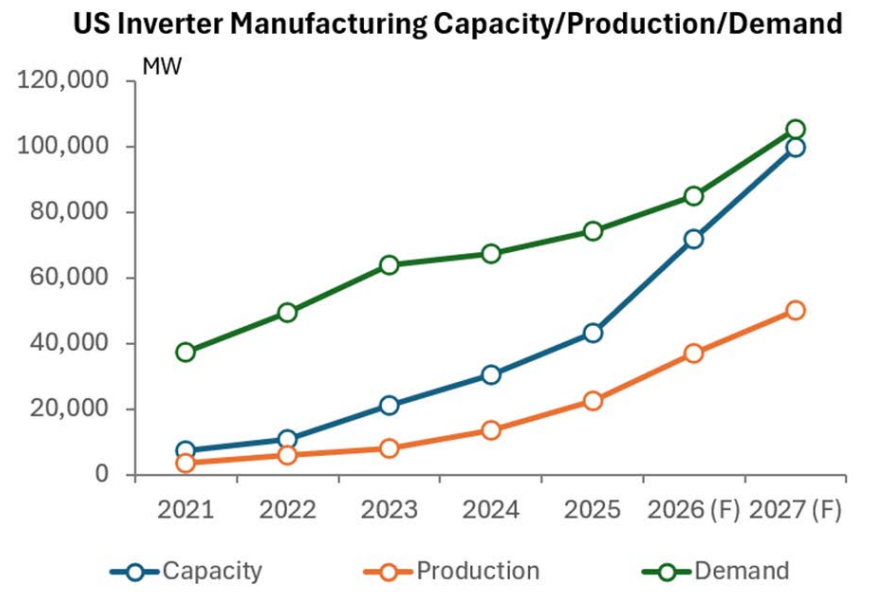
EPC Power's recently opened 27GW PCS production facility in the US, scalable to 40GW, has increased the share of domestically owned manufacturing capacity. However, once Power Electronics' 40GW facility becomes operational, European-headquartered and US-headquartered manufacturers will hold nearly equal shares of US capacity between 40% and 45% each.

The same trend is true for companies based outside of Europe. Japanese manufacturer TMEIC operates a 2.25GW facility that opened in 2025, while Israeli company SolarEdge established its Austin, Texas facility by the end of 2023. Even some Chinese manufacturers are adapting; Sungrow, despite facing increasing restrictions, continues to evaluate its options for serving the US market.



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Source: *PV InverterTech Bankability Ratings Report; Sept 2026*

Figure 1. By the end of 2027, US-based inverter manufacturing capacity is projected to reach close to 100GW



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Source: *PV InverterTech Bankability Ratings Report; October 2026*

Figure 2. US inverter manufacturing capacity, production, and demand are converging as domestic facilities ramp up

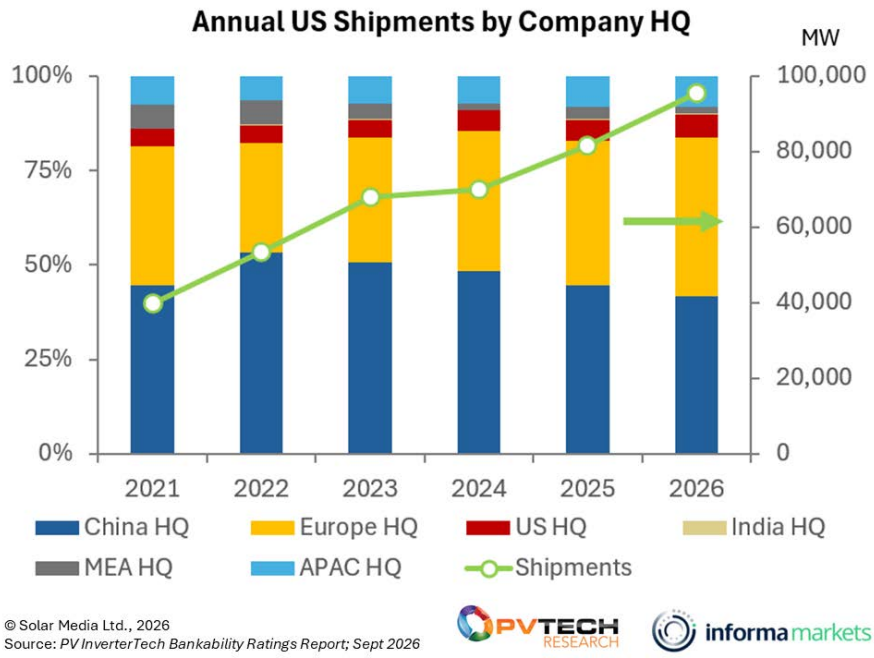


Figure 3. Annual US inverter shipments by company headquarters location reveal persistent Chinese dominance, but a growing European presence

This represents a fundamental shift in the industrial landscape. European companies, leveraging decades of engineering expertise and established customer relationships, are positioning themselves as the primary alternative to Chinese dominance. Their success in the US mirrors their even more dramatic expansion at home, where Europe has surpassed 100GW of inverter manufacturing capacity, over 90% owned by European-headquartered companies.

Perhaps more significant than who owns the capacity is how rapidly domestic production is catching up with US market demand. In 2021, the disparity was stark: US inverter supply reached nearly 40GW, predominantly imported from overseas, while US-based manufacturing facilities produced just 3.5GW. Of this domestic production, a portion was exported to other markets, meaning even less than 3.5GW actually served the domestic market, barely 10% of total US supply.

By 2026, this gap has narrowed considerably. Total US inverter demand is expected to reach approximately 90GW, while US-based production is projected to climb to around 35GW. Though some of this production will serve export markets, the vast majority is now destined for domestic use, representing roughly 40-43% of total US demand.

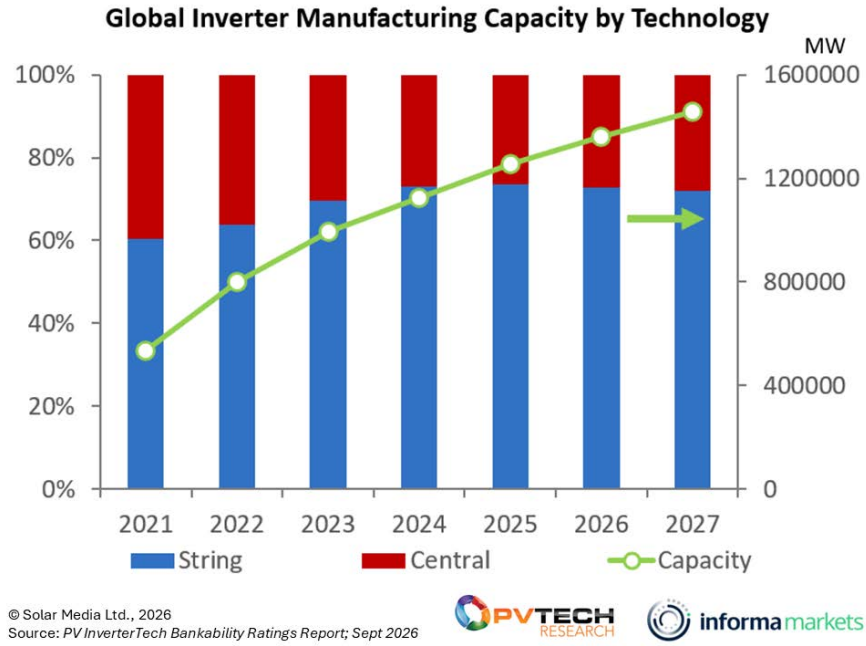


Figure 4. The global inverter market is shifting toward string technology and away from central inverters, particularly for utility-scale projects

With total manufacturing capacity approaching 70GW by year-end, domestic production could potentially satisfy an even larger share of demand if utilisation rates improve.

However, capacity utilisation has remained relatively stable at around 50% throughout this expansion period, suggesting that manufacturers are building ahead of demand or facing ramp-up challenges. This utilisation rate means that while installed capacity reaches 70GW in 2026, actual production output sits closer to 35GW. If facilities can increase utilisation toward industry-standard levels of 75-85%, domestic production could approach 60GW or more, further reducing reliance on imports.

The trajectory is clear: what was once an almost entirely import-dependent market is rapidly transitioning toward domestic self-sufficiency. If current trends continue, US-based production could satisfy the majority of domestic inverter demand by 2028-2029, fundamentally reshaping supply chain dynamics and reducing vulnerability to international trade disruptions.

Chinese manufacturers still dominate supply

While US-based manufacturing capacity is expanding rapidly, the composition of actual inverter shipments tells a different story. Chinese-headquartered companies have maintained a remarkably consistent grip on the US market, accounting for over 40% of annual shipments throughout recent years, albeit with a gradual decline.

This dominance persists despite escalating trade restrictions and tariff pressures, underscoring the competitiveness and established market position of Chinese manufacturers.

European-headquartered companies represent the second-largest source, supplying a projected 40% of the US market in 2026 and narrowing the gap with Chinese competitors.

Critically, as European manufacturers commission new US-based facilities, an increasing share of these shipments now originates from domestic production rather than imports. Companies like SMA Solar and Power Electronics are transitioning from serving the US market through imports to manufacturing locally, meaning that 40% of the European share increasingly represents US-made products from European-owned facilities.

US-headquartered companies, meanwhile, are gradually increasing their share of domestic supply, approaching 6% in 2026 compared to just 4% in 2021. While this represents a 50% increase of market share, the pace remains relatively slow. Domestic manufacturers face intense competition from both established Chinese suppliers and rapidly scaling European competitors that benefit from decades of global market experience.

This creates an intriguing dynamic: while European companies are projected to control 30% of US manufacturing capacity, they currently supply 40% of actual shipments in 2026. This suggests European manufacturers are operating at high utilisation rates and may need additional capacity to maintain market share. Conversely, Chinese companies' supply has dropped to 40% of US demand while they hold no domestic manufacturing capacity, making their market position increasingly vulnerable to policy interventions.

The coming years will likely see a dramatic shift in these proportions. As European-owned US factories reach full production and domestic content requirements tighten, the 40% Chinese share faces inevitable erosion. The question is not whether this shift will occur, but how quickly, and whether US-headquartered companies can capture a meaningful portion of the market their own government policies are reshaping.

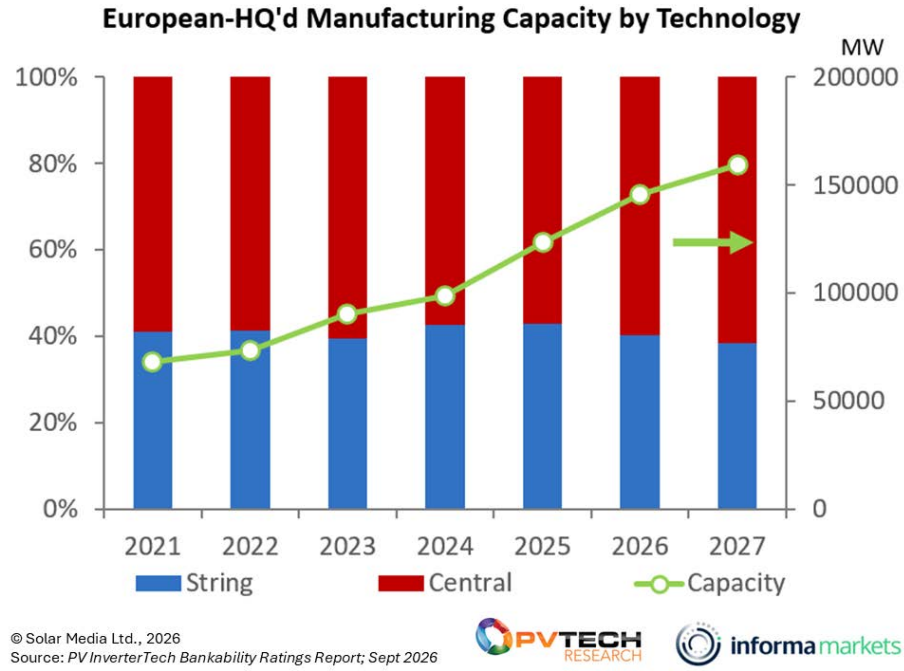


Figure 5. European manufacturers are favouring central inverter technology over string technology, with much of this capacity focused on newer modular central designs

String inverters versus central inverters

The European manufacturers establishing US production capacity bring with them a distinctive technological approach that sets them apart from the broader global market, and this difference may significantly influence the competitive landscape.

String inverters have historically accounted for more than half of inverter technologies, and this trend is only continuing. In 2021, string inverters accounted for approximately 60% of total global manufacturing capacity. By 2026, this figure is projected to exceed 70%.

This transition reflects compelling operational advantages: modern high-power string inverters deliver superior energy yields, modular reliability and significantly lower lifetime operating costs. When a central inverter fails, megawatt-scale blocks of a solar farm go offline simultaneously. In contrast, a single string inverter failure affects only a tiny fraction of total capacity, minimising downtime and financial impact.

Maintenance considerations further favour string technology. On-site staff can quickly swap a failed string inverter with a spare unit within hours using standard tools. Central inverters require heavy machinery, concrete pads and specialised engineers, translating to extended downtime and higher labour costs.

Chinese manufacturers, which account for approximately 90% of annual global inverter manufacturing capacity, have driven this global shift by concentrating heavily on string technology. They recognised early that string inverters aligned well with distributed generation trends and rooftop solar expansion, and their aggressive investment in string production capacity, combined with competitive pricing and rapid innovation cycles, has reshaped global market dynamics.

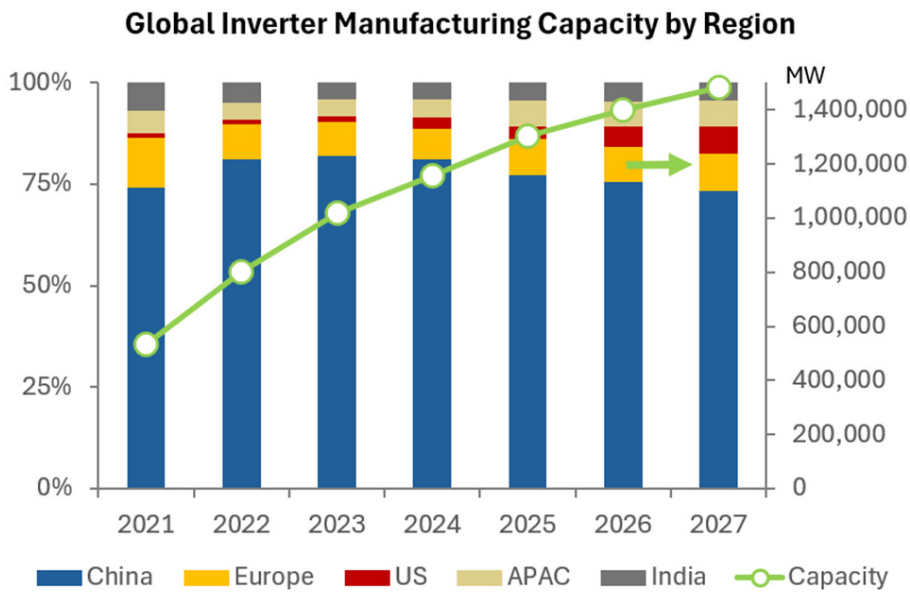
European manufacturers, however, present a notable exception to this global trend. Annual manufacturing capacity data for European-headquartered companies shows string production has remained relatively stable at approximately 40% each year, with central inverters continuing to dominate their portfolios.

Several factors explain this European positioning. Companies such as SMA Solar and Switzerland's ABB built their reputations around utility-scale and commercial projects where central inverters dominated for decades. Significant capital invested in central inverter production lines creates financial inertia that discourages rapid technology shifts.

Many European manufacturers position themselves as premium suppliers offering high-reliability central and modular inverters with advanced grid support functions, longer warranties and superior service for harsh environments. European utility-scale customers were also slower to adopt string inverters, maintaining demand for proven central and modular solutions.

An important nuance in this landscape is the emergence of modular inverter technology, which blurs the traditional distinction between string and central systems. While technically classified as central inverters in industry data, modular inverters represent a hybrid approach that captures advantages from both technologies. They employ multiple smaller, swappable inverter blocks housed together in a single large skid or station at multi-megawatt scale. Rather than relying on one massive monolithic core, they distribute power conversion across independent modular sub-units.

This architecture delivers the redundancy and multi-MPPT (Maximum Power Point Tracking) benefits characteristic of string arrays while maintaining centralised infrastructure and scale advantages.



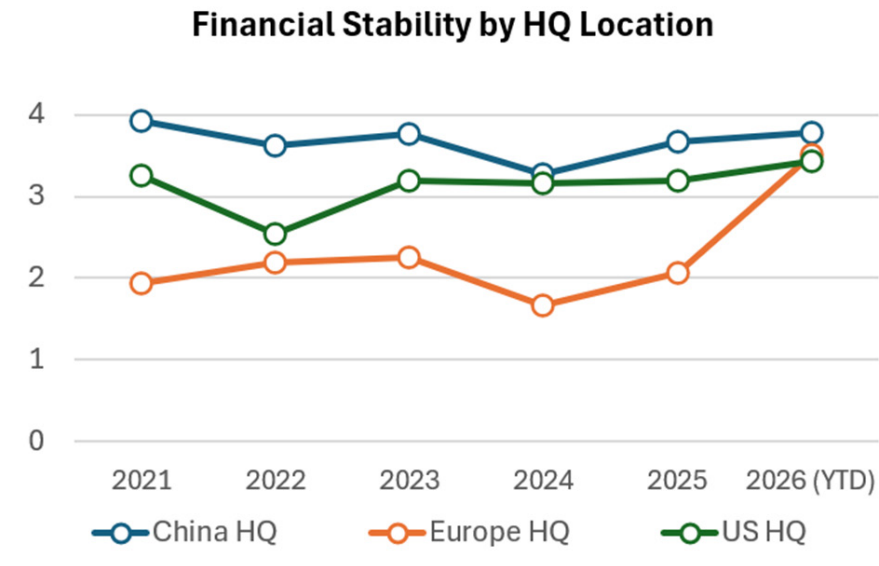
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Source: *PV InverterTech Bankability Ratings Report; Sept 2026*

Figure 6. Global inverter manufacturing capacity is shifting as China's share gradually declines while other regions expand

Both European and Chinese manufacturers have invested in modular inverter technology, recognising its potential to bridge the gap between traditional central and string approaches for utility-scale applications.

Not all European manufacturers have maintained the same focus. Companies such as Austria's Fronius and Germany's KACO have primarily concentrated on string technology and are well-positioned if the trend toward string continues. Meanwhile, manufacturers including SMA Solar and Spain's Ingeteam have begun diversifying their portfolios, shifting some focus toward large-scale string inverters in recent years.

This technological positioning has significant implications for the US market. As European manufacturers establish substantial production capacity in the US, they are bringing with them a portfolio weighted toward central and modular inverters, a different technological mix than the string-dominated approach of Chinese competitors. Whether this represents a strategic advantage or disadvantage depends on how US utility-scale preferences evolve.



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Figure 7. While Chinese inverter manufacturers have long led in financial stability, European and American competitors have narrowed the gap in 2026

If US developers continue favouring string technology for its operational flexibility, lower maintenance costs and faster deployment, advantages that align well with aggressive renewable energy targets and accelerated deployment timelines, European manufacturers may find themselves competing with a product mix that doesn't match market demand. Conversely, if large-scale utility projects prioritise the advanced grid support functions, proven reliability and sophisticated capabilities that European central and modular inverters offer, their strategic positioning could prove prescient.

The critical question concerns which technology will be preferred by the US utility-scale solar sector. The answer likely depends on project scale, grid requirements, total cost of ownership, policy frameworks and risk tolerance.

The conditional approval bottleneck

While existing inverter models remain compliant with US policy requirements, the future hinges on how quickly new models can receive FCC approval, a process shrouded in uncertainty.

The FCC's inverter ban closely mirrors an earlier policy applied to consumer-grade internet routers. In that case, conditional approvals for large manufacturers were granted within weeks. However, notably, no Chinese companies received conditional approvals, suggesting the process may effectively exclude Chinese manufacturers regardless of their technical compliance.

The approval process requires manufacturers to demonstrate "serious effort" to onshore production, though it remains unclear whether every approved model must actually be manufactured domestically. The Department of War and Department of Homeland Security play key roles in determining conditional approvals and can reverse them if onshoring commitments aren't met.

This creates a potential innovation bottleneck. New inverter models could face extended development cycles of 6-12 months, delaying advanced features precisely when the industry needs them most. The impact may be particularly acute for battery energy storage systems (BESS), where rapid innovation is ongoing and developers risk being locked out of state-of-the-art

technology.

If European manufacturers with established US facilities receive faster approvals for their central and modular inverter models while Chinese string inverter manufacturers face delays or denials, the policy framework could inadvertently favour one technology approach over another, regardless of technical merit or market preference.

Can US manufacturing meet demand?

On paper, the numbers look promising. The US is forecast to reach 60GW of annual inverter manufacturing capacity by 2027, figures that appear to align with annual solar installation volumes. A substantial portion of Europe's inverter production is also exported to the US, providing additional supply.

This US manufacturing expansion is part of a broader global shift in inverter production. China's share of global manufacturing capacity peaked at 81% in 2023 but is declining to a projected 75% by 2027, as Europe, the US and India have steadily increased their production footprints. This diversification reflects both policy interventions across multiple markets and strategic decisions by manufacturers to establish regional production hubs closer to demand centres.

But several critical challenges remain. Concerns exist about shortages in inverters with advanced networked communication features and grid-interactive capabilities, precisely the sophisticated equipment that utility-scale projects require. Limited availability of specialised products for energy storage integration could constrain BESS deployment, and gaps exist in residential versus utility-scale product portfolios among domestic manufacturers.

The technology mix of US manufacturing capacity adds another layer of complexity. With European manufacturers establishing substantial capacity weighted toward central and modular inverters while global demand trends decisively toward string technology, a potential mismatch could emerge between what's being manufactured domestically and what developers actually want to purchase.

Perhaps most critically, newly established US facilities lack the operational history of established Asian manufacturers. Early production quality issues could undermine market confidence and slow adoption, creating a vicious cycle that delays the transition to domestic supply.

Even with domestic assembly, true supply chain independence remains elusive. Critical components such as semiconductors, capacitors and control boards still often originate from Asia. Moreover, no additional large-scale inverter manufacturing facilities are currently known to be in planning stages beyond those already announced. If the current expansion trajectory doesn't continue, US production could plateau rather than continue growing, leaving the market vulnerable to supply constraints.

The China question

While the FCC ban applies to all non-US manufacturing regardless of country of origin, Chinese companies face unique challenges. The conditional approval process evaluates corporate structure, suggesting Chinese-owned companies will encounter greater difficulty than their European or American counterparts.

Chinese manufacturers dominate solar PV inverter imports to the US, with Sungrow as the largest single importer. While Sungrow operates manufacturing facilities across China, Europe and the broader APAC region, a portion of its US imports originates from European production sites, a strategy that may provide some flexibility under current rules.

The regulatory environment differs notably from Europe, where restrictions focus more on headquartered location. In the US, the emphasis is on manufacturing location, theoretically allowing Chinese companies to shift production to US soil or non-FEOC countries. However, practical barriers, including the conditional approval process, political sensitivities and the need to demonstrate serious onshoring commitments, make walking this path considerably more difficult for Chinese firms without an established US presence.

Companies with existing US manufacturing capacity can scale more quickly by hiring additional contractors within their existing facilities. Those without a US footprint face the considerably more complex challenge of establishing entirely new operations in an unfamiliar regulatory and business environment.

The technology dimension adds further complexity. Chinese manufacturers have invested heavily in string inverter production, the technology segment experiencing the strongest global growth. If they are effectively excluded from the US market through the conditional approval process, American developers may find themselves cut off from the world's leading suppliers of the inverter technology that global markets increasingly prefer.

The financial dimension reinforces these concerns. Chinese inverter manufacturers have demonstrated consistent financial stability, maintaining average Altman Z-scores above 3.0, well within the 'safe zone', throughout 2021-2026. Developed by NYU professor Edward Altman, the Altman Z-score is a financial formula used to predict the likelihood that a company will go bankrupt within the next two years and is the standardised benchmark for comparing the financial health of manufacturers in the PV Tech Bankability Ratings.

This financial strength has enabled sustained R&D investment and rapid scaling of string inverter production capacity. By effectively excluding these manufacturers, US policies may be cutting developers off not only from technology leaders but also from the most financially stable segment of the global inverter supply base.

The 2026 data, however, introduces a complicating factor that transforms this straightforward narrative. European manufacturers' average Altman Z-scores have surged to 3.51 in 2026 year-to-date, finally converging with the financial stability that Chinese manufacturers have consistently demonstrated. US-headquartered manufacturers have similarly strengthened to 3.43, creating an unprecedented alignment in financial health across all three regions.

This convergence suggests that the combination of IRA manufacturing incentives, domestic content bonuses and FEOC-driven market protection may be successfully enabling non-Chinese manufacturers to build the financial foundation necessary for long-term competitiveness.

Yet multiple factors counsel caution in interpreting this as a definitive turning point. The improvement is directly tied to policy intervention rather than market-driven competitive strength, European manufacturers' scores jumped from 1.66-2.25 in prior years to 3.51 as they commissioned new US facilities and captured market share from restricted Chinese competitors.

Revenue growth and improved margins from premium pricing in a supply-constrained environment are strengthening balance sheets, but this raises a fundamental question: does this represent genuine operational excellence, or subsidy-dependent financial health that could deteriorate if policy support changes? The historical volatility of European manufacturers' financial metrics, swinging from 1.93 to 3.51 over just five years, demonstrates a pattern of instability that one strong partial-year doesn't erase.

Moreover, the 2026 figure represents year-to-date data that may not reflect full-year performance, and could be influenced by seasonal factors or large project timing.

The sustainability of this convergence will only become clear over the next several years as newly-established facilities prove their operational consistency, market dynamics stabilise and the durability of 2026's financial improvements is tested. If European and US manufacturers can maintain financial stability comparable to their Chinese competitors while delivering the technology sophistication and supply reliability that the market demands, then policy interventions will have successfully created the conditions for genuine supply chain independence.

If, however, the 2026 improvement proves temporary or dependent on continued policy protection, US developers may find themselves trading dependence on financially robust Chinese manufacturers for dependence on policy-supported alternatives whose long-term viability remains uncertain.

What happens next?

The US inverter market stands at a critical juncture. Several scenarios could unfold:

The optimistic scenario

Conditional approvals are granted relatively quickly, European and American manufacturers successfully scale production and the US achieves substantial supply chain independence within three to five years. The technology mix of domestic production proves well-matched to US utility-scale preferences, with European manufacturers' premium positioning capturing high-value market segments.

Innovation continues largely unimpeded, and the transition strengthens both energy security and domestic industrial capacity.

The pessimistic scenario

Conditional approvals face significant delays, quality issues emerge at newly-established facilities and developers struggle to navigate interconnection queue complications when switching inverters. A technology mismatch emerges as domestic capacity focuses on central/modular inverters while developers increasingly prefer string technology.

Innovation lags as developers are locked out of cutting-edge technology, particularly for BESS applications. Installation forecasts prove overly optimistic as supply constraints and regulatory uncertainty slow deployment.

The stagnation scenario

Initial manufacturing expansion succeeds in establishing 60GW of capacity, but growth stalls as no additional facilities are planned. The market achieves partial supply chain independence but remains dependent on imports for specialised equipment and upstream components.

A two-tier market emerges: established projects using grandfathered equipment and new projects facing higher costs and limited technology options.

The segmented market scenario

Different technology preferences emerge across market segments. Large utility-scale projects with stringent grid code requirements favour European manufacturers' central and modular inverters, validating their strategic positioning. Residential, commercial and smaller utility projects increasingly prefer string technology, creating sustained demand for products that domestic manufacturing capacity may not adequately supply.

A market in flux

The reality will likely fall somewhere between these scenarios, varying by market segment. Utility-scale projects with sophisticated communication requirements may face different dynamics than residential installations. BESS projects may experience more significant innovation delays than solar PV. Developers with strong relationships with European manufacturers may navigate the transition more smoothly than those heavily reliant on Chinese suppliers.

What's clear is that the US solar inverter market is undergoing a fundamental restructuring with implications extending far beyond regulatory compliance. This transformation affects deployment costs, technology development trajectories, competitive dynamics and the US' broader energy security strategy.

The question isn't whether the market will change; that transformation is already underway. The questions are whether this policy-driven restructuring will ultimately strengthen or weaken the country's renewable energy sector, and whether the technology mix of domestic manufacturing capacity will align with market preferences.

Will the European focus on central and modular inverters match US utility-scale preferences, or will developers increasingly demand the string technology that dominates global markets? Will innovation keep pace despite regulatory hurdles? Will the benefits of supply chain independence outweigh the costs of transition and potential technology mismatches?

The answers will emerge over the next several years as conditional approvals are granted or denied, new facilities ramp production, quality and reliability are proven or questioned, technology preferences crystallise across different market segments and developers navigate an increasingly complex procurement landscape.

For now, the US inverter market remains in flux, caught between the old world of Chinese manufacturing dominance and string technology leadership, and an uncertain future of domestic production dominated by European manufacturers with a different technological approach. The decisions made in the next 12-24 months will shape the US' solar infrastructure for decades to come. ■

The data underpinning this article came from the 'PV InverterTech Bankability Ratings' report. For further information, visit research.pv-tech.org

Author



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PV plant construction in the cyber age

Technology | AI-powered robotics can be harnessed as a workforce enhancement tool for utility-scale solar construction. Adam Bernardi, Jami Stone and Puneet Puri look at how the combined technologies are changing the equation in the field



Credit: Burns & McDonnell

Burns & McDonnell has already deployed a combined AI and robotics system on two utility PV projects in the US

Utility-scale solar construction is built on repetition. Across projects spanning hundreds or thousands of acres, construction teams repeat the same activities thousands of times to transform rows of steel into operating power generation facilities.

Module installation is a prime example. Today's photovoltaic modules can weigh upward of 90 pounds, and thousands may be installed in a day across a large project. Traditionally, that means workers move modules along rows, lift them into position and secure them to the tracker. During a shift, the crews will repeat this process thousands of times.

The repetitive nature of the work makes solar an obvious candidate for automation. It's easy to imagine a solar installation project functioning like a factory. But one major complication stands in the way: a solar construction site is nothing like a factory floor.

Industrial automation succeeds in highly controlled environments where equipment, materials and workstations can be positioned precisely. Construction takes place across changing terrain and in heat, cold, wind, rain, snow, dust and mud. On a construction site, materials and people are constantly moving, and conditions in one area can be very different from those even a few hundred yards away.

This is why construction robotics has been a difficult problem to solve. Today's advances in artificial intelligence are finally changing the equation.

Bringing intelligence into the field

AI-powered robotics offers a way to combine the repetitive capabilities of industrial automation with the adaptability required on a construction site. Burns & McDonnell evaluated companies working on this problem and partnered with Gritt to deploy its technology for solar module installation in the field.

The Gritt product is not a module-installing robot. It is a generalised physical intelligence for construction, a combined AI and robotics system that builds an understanding of the jobsite and supports multiple task models over time. Solar module pick-and-place is its first task model, with the underlying intelligence designed to extend to additional construction workflows.

That intelligence runs on an attachment mounted to equipment already familiar on construction sites, such as skid steers. Rather than requiring builders to adopt a new class of purpose-built machinery, Gritt's platform introduces advanced automation without requiring a new equipment fleet.

In the field, a Gritt-enabled skid steer moves down a row with the supply of modules aboard. A robotic arm mounted to the skid steer picks up each module, identifies its connection points and positions it on the tracker with a high degree of precision, guided by Gritt's AI rather than by an operator manually controlling each movement.

An operator remains in the skid steer to oversee its movement. A technician monitors the robotic system. Craft workers complete the installation once the module is placed.

Gritt designs safety into how the system shares the site with people. Its software defines its work zone as a precise three-dimensional space that follows the actual shape of the work rather than a simple radius. Materials and other objects can enter that space, but if a person steps into it, Gritt's spatial AI pauses the machine until the zone is clear.

The objective is safe, precise, repeatable placement across thousands of installations, freeing skilled workers from the most physically demanding portion of the workflow to focus on higher-value construction activities.

Proving it in the field

Promising performance in a demonstration is different from depending on new technology in production. The only way to close that gap is to put the technology to work on real projects, under real conditions.

Burns & McDonnell has already deployed Gritt on portions of two utility-scale solar projects, Gibson City (a 346MW project in Illinois) and Karn (a 105MW project in Michigan). Each project involved different trackers and different modules, requiring different equipment configurations. The machines installed the modules through high heat, high humidity and lightning stand-downs, and within the

site access windows, crew schedules and logistics of active construction. A third field deployment is planned at Glacier Moraine, a 210MW project in Illinois, for the fourth quarter of 2026.

Nothing in construction goes perfectly, and these deployments were important opportunities to gather feedback from real-world worksites.

Before the industry can depend on robotic systems across the installation of hundreds of megawatts, it needs to know how the equipment behaves in production: what stops it, how quickly it returns to work, where its operating limits are and how people work safely around it.

Tests in a laboratory can't answer these questions. Only repetitions on a jobsite can. Every issue that surfaces at pilot scale must be resolved before it can affect a much larger installation. For example, early pilots provided the opportunity to adjust the speed at which the robot arm worked to establish a comfort level without impacting overall productivity.

The ability to learn from repetitions distinguishes Gritt's physical AI from conventional automation. A traditional automated system can be programmed to perform a defined task repeatedly under known conditions. Gritt's construction intelligence layer uses perception and software to identify what it sees and respond to variations in its environment.

The physical AI is trained to understand the construction environment—not only in the immediate area where it may be working, but the site context around it, including equipment, materials, people, terrain and changing conditions. The machine identifies where a module needs to be placed and adjusts its arm to factor in every relevant variable before placing it. When conditions fall outside the system's operating confidence, it pauses for review rather than proceeding without sufficient certainty.

Every repetition and every new condition provides data that improves the model. Field deployments therefore serve two purposes at once. They test whether the technology can support construction today, and they improve how it will perform tomorrow. With Gritt, updates can be sent directly to machines. Gritt's system is constantly learning from its environment, transferring those learnings into new model weights, then pushing those weights to each machine as an over-the-air update, similar to a smartphone. An update that improves a capability on one site improves it on every site.

That feedback loop is one of the most consequential characteristics of AI-powered robotics. The mechanical equipment is only one part of the system. The intelligence keeps improving as developers and contractors learn from each deployment, so the lessons of one project inform the next.

Expanding what the workforce can accomplish

The industry is tasked with completing increasingly large projects on demanding schedules while skilled craft labour remains constrained. At the same time, modules have become larger and heavier, introducing additional strain on the installers. Finding ways to reduce the physical demands on construction teams while expanding what those teams can accomplish is increasingly driving success in project execution.

As robotics becomes more capable, questions about its effect on the construction workforce are inevitable. Experience to date suggests a more useful and relevant question: how can automation change the allocation of work so construction teams can accomplish more?

Robotic module installation remains a human-machine operation. People operate equipment, monitor robotic systems, manage logistics, respond to exceptions and make decisions about changing field conditions. The robot provides leverage by taking on a particularly repetitive and physically demanding portion of that workflow.

Those roles will evolve as the technology matures. Today, a technician may monitor one robotic unit. As the work scales, each technician may oversee several machines. Construction professionals will need to understand not only traditional means and methods, but also how to operate, supervise and troubleshoot increasingly intelligent equipment.

It is more useful to think of robotics as a workforce enhancement tool than as a substitute for labour. It is a way to expand the productive capacity of construction teams while shifting the most repetitive physical work from people to machines.

The implications extend beyond individual tasks. Once a team understands what automated equipment can do reliably, it can begin planning material staging, logistics and construction sequencing around those capabilities. Engineering and constructability decisions may also evolve. Initially, automation must adapt to the realities of construction. As the technology becomes embedded in work methods, construction processes can begin to adapt to take greater advantage of automation.

Utility-scale solar offers a particularly useful proving ground because the industry's challenge is fundamentally about scale. Enormous amounts of infrastructure must be built, and each project contains hundreds of thousands of opportunities to install, learn, improve and repeat.

That is the trajectory of the partnership between Burns & McDonnell and Gritt. Two projects have demonstrated the technology in production, with a third coming soon. The companies have committed to scaling robotic installation toward a gigawatt of solar construction in a step that will require additional machines and more people trained to work alongside them.

The future of solar construction is unlikely to be defined by choosing between people and machines. Instead, those who build the future will be the ones who learn how to combine skilled craft, construction knowledge and intelligent equipment. In turn, this means project teams can work with less physical strain, greater consistency and the capacity to build more.

For an industry facing the challenge of rapidly expanding energy infrastructure, that ability to do more may ultimately be the most important measure of progress. ■

Authors



Adam Bernardi leads Burns & McDonnell's Solar Business Line, overseeing strategy, growth and project execution. With experience on both the developer and EPC sides of the industry, he has contributed to 5GW of completed and active solar projects nationwide, including the company's first solar-plus-storage projects.



Jami Stone is a construction project manager at Burns & McDonnell, with a current focus on executing utility-scale solar projects. She has a background in preconstruction, estimating, scheduling, project management and electrical systems in large-scale solar projects.



Puneet Puri is CEO of Gritt AI. Puneet is passionate about building a more resilient, sustainable infrastructure future. Drawing on his background in robotics and AI, he develops practical technologies that improve how critical infrastructure is built. His experience spans autonomous drone technology, robotics algorithms and infrastructure solutions.

Underperformance in fielded solar assets

Bankability | Fleet-level data and field experience suggest that availability, degradation, manufacturing variability and other sources of uncertainty deserve closer scrutiny in solar energy models. Taylor Geer of VDE Americas looks at ways to close the gap between modelled and fielded PV system performance



Credit: Vesper Energy

In 2022, the world officially entered the terawatt (TW) era of solar. After Bell Labs discovered the first practical silicon solar cell in 1954, it took 68 years to deploy the first 1TW of global PV capacity. The doubling time to reach 2TW of capacity took only two years. Many analysts expect global annual solar PV capacity additions to reach 1TW by 2030. Future historians will undoubtedly look back at the moment we are living through now as a time of great transition.

Whether the terawatt era for solar energy is truly transformative depends on public trust in our ability to deploy long-lived power systems. In a gigawatt-scale market, performance issues in operating PV power plants are painful. At the terawatt scale, chronically underperforming solar assets and portfolios are a material threat to consumer and investor confidence. To satisfy consumers, an increasingly solar-powered electrical grid must meet customer expectations for resilience, safety and affordability. To satisfy investors, solar assets and portfolios need to reliably deliver predictable cash flows and investment returns while limiting downside risks.

Recognising that accurate PV system performance characterisation is foundational to project financing, development and risk mitigation, here I review recent trends in fielded system availability and performance, based on both published data and direct experience. Moreover, I explore how optimistic PVsyst model input assumptions may be contributing to reports of solar project underperformance. Throughout, I emphasise the critical role of technical due diligence in reducing the uncertainty of lifetime performance projections.

The significance of solar's terawatt era will stand or fall on bublic trust in the longevity of PV power plants

Auditing system availability assumptions

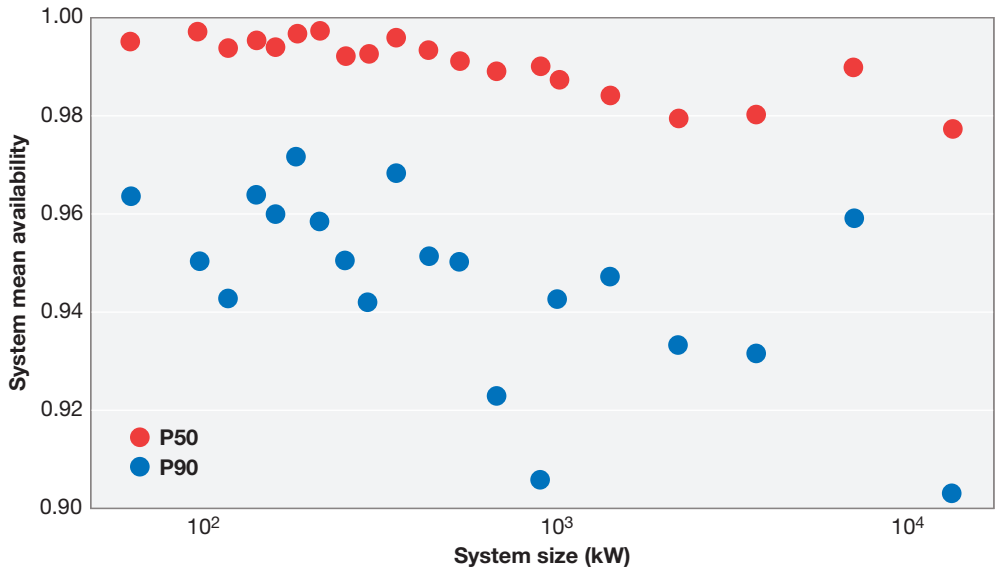
Underperformance in operational solar assets often results from the accumulation of many small losses, some of which are difficult to isolate due to measurement uncertainty. The exception to this general rule is availability, as these losses are often episodic but potentially severe. This is especially true in utility-scale PV power systems, where the loss of a single central inverter can significantly reduce instantaneous power generation capacity and daily energy harvest.

In industrial applications, availability is often defined as the uptime percentage for a specific piece of equipment. In solar applications, availability is more nuanced, as it could be measured at the system, inverter, subarray, tracker block, tracker row or even string level. Moreover, it could be defined strictly according to technical readiness or more holistically to account for planned or unplanned downtime. Availability can also be expressed as a time-based or energy-based metric.

In practice, the solar industry generally defines availability as an inverter-level and energy-weighted metric. In other words, the PV system availability metric is generally insensitive to partial capacity reductions caused by inverter thermal derating, stalled trackers or string-level failures. Even using this relatively forgiving grading system, anonymised fleet-level data suggests that large-scale solar assets are not meeting investors' availability expectations.

Specifically, the PV Fleet Performance Data Initiative (PV Fleet), overseen by the US Department of Energy and the National Laboratory of the Rockies, collects operational PV power data in a secure, central database to benchmark cumulative performance and analyse trends. Since 2020, a team of investigators led by Chris Deline has published technical reports and journal articles on PV Fleet's methodology, insights and metadata analyses.

In a February 2024 technical report titled 'Availability and Performance Loss Factors for US PV Fleet Systems', the PV Fleet team analysed inverter-level availability data for over 1,100 operational PV systems deployed across the contiguous US [1]. Though the high-level processed data shows a median (P50) system-level availability of 0.99, consistent with typical performance model input assumptions, the detailed analysis paints a more complicated picture.



Credit: National Laboratory of the Rockies

Figure 1. The PV Fleet dataset shows a negative trend in system availability with increasing system size

Startup issues in year one

Startup issues result in lower year one system availability. To arrive at a 99% median availability, PV Fleet investigators first filtered out the first six months of performance data to account for system startup issues. In other words, fleet-level data clearly show that availability is low for the first months of operation, presumably reflecting the difficulty of bringing large systems online. Specifically, inverter-level availability rises steeply over the first six months of system operation but does not reach a steady-state level until the end of the first year.

As my colleague Lisa Casey, director of technical advisory at VDE Americas points out, operational readiness is an area the industry needs to take a closer look at. "Industry-wide reliance on optimistic schedules, combined with unexpected delays such as weather events and equipment deliveries to the site, can significantly constrain startup timelines," she explains. "This compression can reduce the opportunity for comprehensive operational testing—including stow verification and full system checkouts—and may also curtail the period of sustained, stable operation needed to confirm consistent and repeatable system performance. As a result, many projects are turned over before full operational readiness and long-term reliability have been adequately validated."

This presents a meaningful opportunity for the industry to strengthen startup planning and testing practices and to ensure sufficient time for operational validation prior to project turnover. Without full availability at system startup, it is difficult for project stakeholders to meet acceptance testing requirements, establish a quality system performance baseline, identify actual performance issues and instill confidence in future system performance.

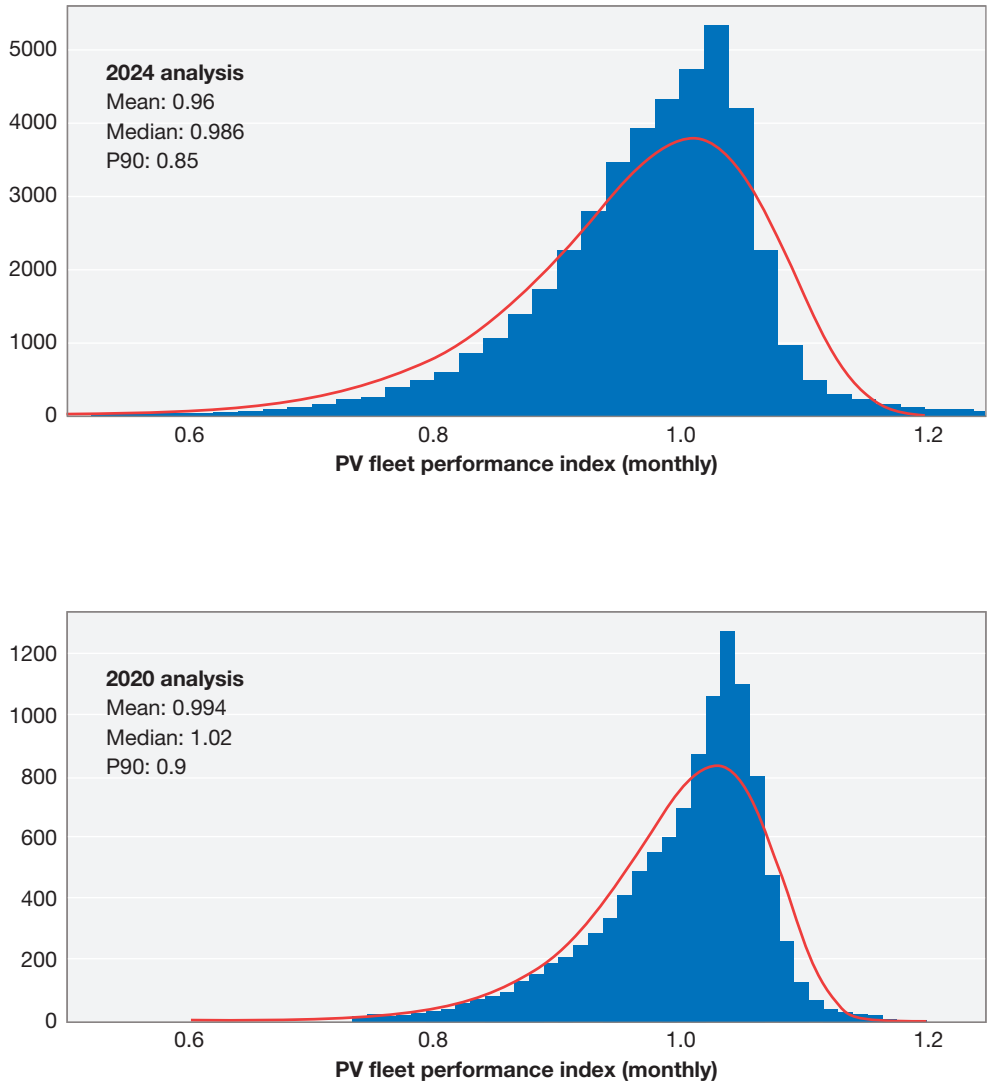
Capacity impacts on availability

Availability tends to drop as system capacity increases. Since the PV Fleet dataset includes a wide range of projects, investigators analysed the relationship between system availability and size. This analysis revealed a negative correlation, indicating that system availability tends to decrease as system capacity increases, as shown in Figure 1. Specifically, after filtering to screen out startup issues and batching the data above and below 1MW, investigators found that the P50 system availability for small systems (20kW–1MW) was 0.994, versus 0.984 for larger systems (>1MW–30MW).

On the one hand, system design architecture and inverter topology could account for this 1% difference in capacity-based median system availability. After all, smaller PV systems often integrate field-swappable string inverters that are relatively easy to replace in the event of a failure. By comparison, utility-scale PV systems generally use central inverters or skid-mounted power conversion systems that can take large blocks of power offline until a specialist can troubleshoot and remedy the problem.

On the other hand, the models used for pro forma financial projections may not account for negative correlations between system availability and system or inverter capacity. Optimistic availability assumptions are especially problematic when replacement parts for central inverters become difficult to source as systems age.

As my colleague Daniel Moghtader, performance engineering manager at VDE Americas, notes, one of the biggest mistakes the industry makes is assuming fielded systems always operate at 99% availability. "In reality, most systems will not operate at 99% availability in perpetuity," he explains. "Some ten-year-old inverter models and brands are not even available today. At some point, the availability of replacement parts will



Credit: National Laboratory of the Rockies

impact system availability. Sophisticated counterparties and diligent independent engineering firms will update their pro forma availability assumptions accordingly to be more conservative."

Indexing PV system performance

Though there are numerous ways to consider and report PV system performance, the PV Fleet team's technical reports generally focus on a performance index metric. This characterises the monthly sum of a system's AC energy harvest divided by a weather-corrected energy production estimate and accounts for both recoverable losses (e.g., availability, curtailment and snow cover) and non-recoverable losses (e.g., PV module material degradation).

One benefit of a holistic performance index analysis—as compared to the more targeted module degradation rate analysis that Dirk Jordan and others described in 'Robust PV Degradation Methodology and Application', in the March 2018 edition of the *IEEE Journal of Photovoltaics*—is that it is sensitive to losses that are recovered in later years [2]. For example, a narrow focus on module-level degradation over time will fail to account for the system-level recovery of temporary inverter clipping losses.

To avoid the complications associated with imperfect on-site sensors, PV Fleet investigators intentionally use satellite-based weather data to assess underperformance across the 1,128 PV systems that comprise its performance index dataset. As a result, the team's findings do not benefit from potentially higher-quality irradiance and temperature data from on-site sensors, which performance engineers and other stakeholders may have access to at the project level. However, high-level trends in the PV Fleet data are consistent with recent field reports from the technical due diligence community.

Trending in the wrong direction

Fleet-level performance index results were lower in 2024 than in 2020. After filtering the raw data to remove snow, availability and startup losses, the PV Fleet team calculated the monthly performance index value for each PV system in its database. Analysing nearly 44,000 system-months of data, investigators found that the P50 fleet-level performance index had dropped from 1.02 in 2020 to 0.986 in 2024. Moreover, the mean and downside (P90) performance index values had also decreased over the same timeframe from 0.994 and 0.9 in 2020 to 0.96 and 0.85 in 2024, respectively, as shown in Figure 2.

Figure 2. PV Fleet's analysis shows decreases in the mean, median, and downside performance index for its 2024 dataset (top) compared with its 2020 dataset (bottom)

Drilling further into the data, the investigators also examined the monthly performance index on a per-system basis. This analysis revealed mean and downside (P90) system-level performance index values of 0.95 and 0.83, respectively. Here again, the 2024 results were worse than those in 2020, when the P90 system performance index was 0.9, indicating that 90% of systems performed within 10% of the expected value.

Though the downward trend in the PV Fleet data may reflect some age-related effects, it is also consistent with recent field forensic reports. Specifically, many in the technical due diligence community are concerned that the PV module value-engineering pendulum has simply swung too far in the wrong direction. Though everyone benefits when manufacturers strip unnecessary costs out of the value chain, the reverse is also true. It hurts everyone involved when cost reductions come at the expense of fielded system reliability and performance.

"At VDE, we are seeing an increase in certain types of field failures, including issues associated with junction boxes and PV connectors," notes Casey. "While these observations can have multiple contributing factors, they raise concerns that ongoing cost and design optimisation efforts may be affecting long-term durability. We are also seeing changes in module construction—such as reduced material thicknesses and tighter component tolerances—that may be contributing to increased sensitivity to field conditions. Overall, these trends highlight the importance of balancing cost optimisation with long-term reliability and performance."

Exacerbating market conditions

Market conditions are amplifying underperformance. For PV module manufacturers, the current global solar market conditions are exceedingly challenging. After years of rapid expansion in manufacturing capacity, the worldwide

PV module supply far exceeds market demand, leading to downward price pressure and shrinking margins. Analysts warn that bankruptcies and consolidation are inevitable.

To remain competitive in this only-the-strong-will-survive market, manufacturers are incentivised to reduce the cost of goods sold. At the same time, market-specific regulatory hurdles—such as the Foreign Entity of Concern (FEOC) requirements introduced in the US as part of the One Big Beautiful Bill Act—and tariff structures are not only forcing Chinese module companies to relocate manufacturing facilities but also dictating PV cell technology decisions.

Cherif Kedir, CEO and president of RETC, part of the wider VDE Group, highlights the recent proliferation of ultraviolet-induced degradation (UVID) in operational systems, linked to rising deployment of tunnel oxide passivated contact (TOPCon) technologies. "We're also seeing an uptick in PID [potential-induced degradation], which is surprising," he adds. "For several years, the industry seemed to have solved PID, then all of a sudden, we saw a resurgence."

"There are steps in the manufacturing process that dictate a cell's ability to withstand some of these light-induced degradation modes," Kedir continues. "Manufacturers need to tightly control these steps. But if you take a highly refined manufacturing process out of China and move it to Africa, Eastern Europe, or the US, plant operators need to substantially revise the process definition. Without adequate batch testing, PV modules from a new factory could have a very different reliability profile, even though companies are nominally using the same manufacturing equipment and an identical BOM [bill of materials]."

Minimising model bias and uncertainty

Industry stakeholders rely on PV system simulation software to estimate energy production over time. These site- and technology-specific energy production models are foundational to early-stage economic viability assessments, post-construction acceptance testing and long-term operations. In the context of large-scale solar project development, PVsyst remains the *de facto* industry-standard software platform for PV system energy modelling.

PVsyst is a deterministic, physics-based model that allows users to account for a wide range of factors, including module quality, string mismatch, DC collection system wiring losses, inverter losses, transformer losses, auxiliary losses, array soiling profiles (including snow) and system shading. The software can also model the effects of ageing and degradation, which materially impact energy production over time and, as a result, long-term financial performance.

Given all these technical input variables, energy production modelling in PVsyst is as much an art as a science. If you give the same project-specific dataset to five qualified performance engineers, you might see a 1-3% spread in the production estimates. Moreover, that range of results will be carefully supported by reasonable model input assumptions derived from rigorous, peer-reviewed studies.

While there are many legitimate ways to justify model output variance from a technical perspective, many factors on the front end of a solar project can influence project acceptance down the road. Specifically, PVsyst's energy production estimates are highly susceptible to garbage-in, garbage-out issues, whether due to overly optimistic model input assumptions or unverified performance data.

Input model assumptions

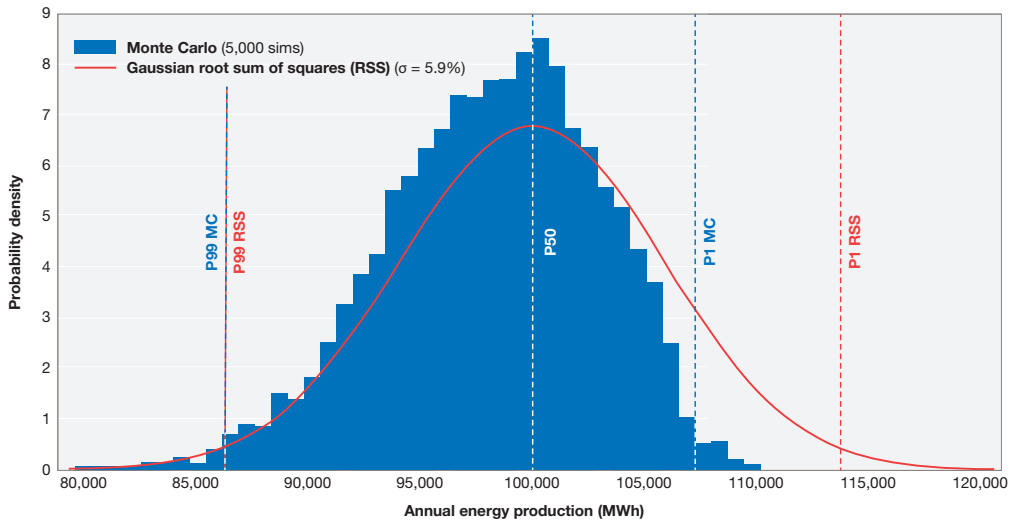
Aggressive model assumptions can bias production estimates. In a 1995 speech on the psychology of human misjudgment, Berkshire Hathaway vice chairman Charlie Munger famously quipped, "Show me the incentive, and I'll show you the outcome." In other words, to understand a specific outcome, it helps to understand what motivates the parties involved.

On the front end of a utility-scale solar project, large developers are incentivised to secure investment capital while minimising the cost of money. These commercial incentives can create pressure for aggressive production assumptions during project development. Therefore, the project developer's pro forma is often aggressive, informed by best-case-scenario model input assumptions.

On the other side of the table, tax equity investors and construction debt lenders understand that the project developer's pro forma is likely optimistic. As a result, owner's engineering firms working on behalf of these institutional investors are tasked with reviewing the independent engineer's energy production model. Therefore, the bank's pro forma is generally conservative, informed by more realistic model-input assumptions and downside risk scenarios.

"When we model things, we not only look at factor effects but also at the uncertainty associated with that effect," explains Moghtader. "With annual performance degradation, as an example, the uncertainty over a ten-year time frame is inherently larger than over a one-year time frame, because modules and other system components do not degrade at identical rates. This mismatch in fielded systems is likely a larger source of underperformance than people realise. Astonishingly, a number of IE firms have historically modelled degradation uncertainty as a constant or omitted it altogether, ignoring differences in degradation profiles and rates, as well as their impacts on module and string mismatch."

"Because capacity test results at handoff rarely exceed 100%, we know that there are optimistic assumptions in the energy models," Moghtader contin-



Credit: VDE Americas

Figure 3. The statistical methods used to assess uncertainty can bias modelled performance

ues. "It's understandable that developers are under pressure to squeeze 1% or 2% more out of a model. However, challenges resulting from aggressive models tend to get passed along through the food chain. An overly optimistic production model can make it difficult to establish an accurate performance baseline, which is critical for mitigating performance risk down the road. Moreover, it can undermine the credibility of the production estimates as a whole and become an impediment to future mergers and acquisitions transactions."

As an example, production models often use a Gaussian root-sum-of-squares (RSS) method to assess how solar project uncertainty affects energy production risk. Because inverter power limiting is a hard physical limit and not a stochastic effect that averages out, a symmetric distribution will tend to overestimate annual energy production in upside scenarios, as compared to a Monte Carlo analysis, which simulates clipping at each hourly step. These structural differences account for the left skew in the Monte Carlo simulation results shown in Figure 3.

Production lot validation

Production lot testing can improve PV module characterisation. In the context of a long-term supply agreement, even seemingly identical PV modules may perform very differently in the real world. Bankability testing of preproduction PV module samples is an ideal way to screen product designs for technical risks and develop a preliminary pro forma during early-stage due diligence. However, periodic production lot testing is required during high-volume manufacturing to prevent systemic issues in fielded systems from eroding investment returns.

"It's not uncommon for developers to sign a 12- to 24-month supply agreement that covers a geographically diverse project portfolio, such as three identical 100MW projects in Florida, Texas and California," says Kedir. "Though the PV modules delivered to these three sites might all carry the same model number, the manufacturer could be shipping from multiple factories. Moreover, manufacturers often have to make material substitutions during an extended commercial production run that are not captured in BOM documentation."

As part of an ongoing production lot testing programme, an independent third party will randomly select crates of modules for follow-up testing to ensure consistent manufacturing quality during high-volume manufacturing. In some cases, factory auditors will send production lot test samples directly from the factory as part of a component-level BOM verification process. In other cases, client representatives will divert test samples from ongoing field deliveries. Depending on the size of the project and duration of the supply agreement, these production lot samples might arrive monthly, quarterly or proportionally (perhaps, one crate out of every 1,000).

Once these randomly selected production lot test samples arrive in the laboratory, RETC will conduct a condensed bankability testing protocol that includes both reliability and performance test sequences. In addition to ensuring that BOM substitutions do not materially degrade reliability, production lot testing also improves the accuracy of the PAN files used to characterise PV module performance.

"Mass-produced modules could perform better or worse than a preproduction design that we evaluated in a bankability report," explains Kedir. "Developers are getting more savvy about these subtle differences. Some of our customers now have us produce PAN files based on production lot test samples. In that case, RETC's third-party-validated PAN files are based on the exact product the manufacturer is delivering to the site, minimising model uncertainty."

"I tend to be cautious about model updates that rely heavily on manufacturer-supplied factory flash test data," adds Casey. "In many cases, these adjustments can increase projected performance by about 0.5% to 1%. However, realising that uplift in the field depends on how consistently solar simulators are calibrated across production lines. Where that consistency isn't well established or independently verified, it can introduce additional uncertainty into the model."

Starting with the end in mind

In real-world applications, solar project bankability is not so much a destination as a process. It is never simply a check-the-box exercise but rather is a measurable outcome under actual conditions of use. After all, the ultimate goal of technical due diligence in a terawatt era is twofold: first, to prevent component-level problems from propagating at scale across large assets or portfolios, and second, to reduce uncertainty so that capital providers are comfortable committing low-cost capital at scale.

To rise to meet the moment, industry stakeholders must remain vigilant to technical risks throughout the entire value chain. Module companies must rigorously assess new cell technologies and product designs during early-stage research and development. During procurement, contract terms must codify bankability testing requirements to identify resilient bills of materials. Once deliveries commence, production lot testing is essential to quickly identify quality escapes and major manufacturing defects.

This work has never been more essential to securing a worthwhile future. At the terawatt scale, unmanaged solar project risks are compounded, multiplied and potentially cascading. Our collective ability to deliver PV power systems that perform reliably in real-world conditions will not only determine whether a specific asset class remains insurable and investable, but also whether future electrical grids remain resilient while accommodating demand growth. ■

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[2] D. C. Jordan, C. Deline, S. R. Kurtz, G. M. Kimball and M. Anderson, 'Robust PV Degradation Methodology and Application', in IEEE Journal of Photovoltaics, vol. 8, no. 2, pp. 525-531, March 2018, doi: 10.1109/JPHOTOV.2017.2779779.

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What summer 2026 tells us about solar generation in a more variable climate

Weather | Europe saw extreme weather throughout summer, from heatwaves and wildfires to a solar eclipse. Solargis industrial engineer and technical consultant Pablo Caballero discusses how asset owners and operators should respond to these extreme events and the value of high-quality data collection in making these decisions

Solar projects are built for long-term operating lifetimes. Over 25 or 30 years, a typical PV power plant could endure heatwaves, unusually cloudy periods, high aerosol events caused by large wildfires, volcanic eruptions or desert dust storms, drought, intense rainfall and, occasionally, even astronomical events such as solar eclipses.

Understanding these phenomena correctly is essential, particularly now that the extreme weather happens more often. A weather anomaly that might once have been treated as an interesting exception can now affect performance reporting, revenue expectations, market exposure, storage operation and investor confidence.

The June-July-August 2026 season was a useful reminder of this.

The summer brought strong regional contrasts in solar irradiation, temperature and precipitation. Some regions experienced exceptionally sunny and hot conditions. Others recorded significant irradiation deficits linked to persistent cloudiness, intensified monsoon activity or unusual precipitation patterns.

For PV project owners, it is not enough to know that production was above or below expectation. The important question is why.

El Niño as an important background signal

El Niño affects atmospheric circulation, cloudiness, precipitation and temperature patterns across large parts of the world. Its influence is not uniform, and regional responses can differ significantly. In some regions, El Niño may contribute to clearer skies and higher irradiation. In others, it may bring increased cloudiness, precipitation or more variable conditions.

This was visible during summer 2026. The spatial contrasts in global horizontal irradiation (GHI) and precipitation across the Pacific region, South America, Papua, Indonesia and parts of east Asia were consistent with the influence of evolving El Niño conditions.

For solar generation, this has two implications.

First, climate oscillations such as El Niño can affect short-term production. Monthly and seasonal anomalies can shift asset performance above or below expectations, depending on the location. A project owner may experience an excellent production month in one market and a disappointing season in another, even though both are linked to the same broader climate pattern.

Second, they can affect how we think about long-term expectations. A strong or rapidly developing climate oscillation does not automatically invalidate a long-term energy yield assessment. Long-term assessments are built to account for natural climate variability. But if a season

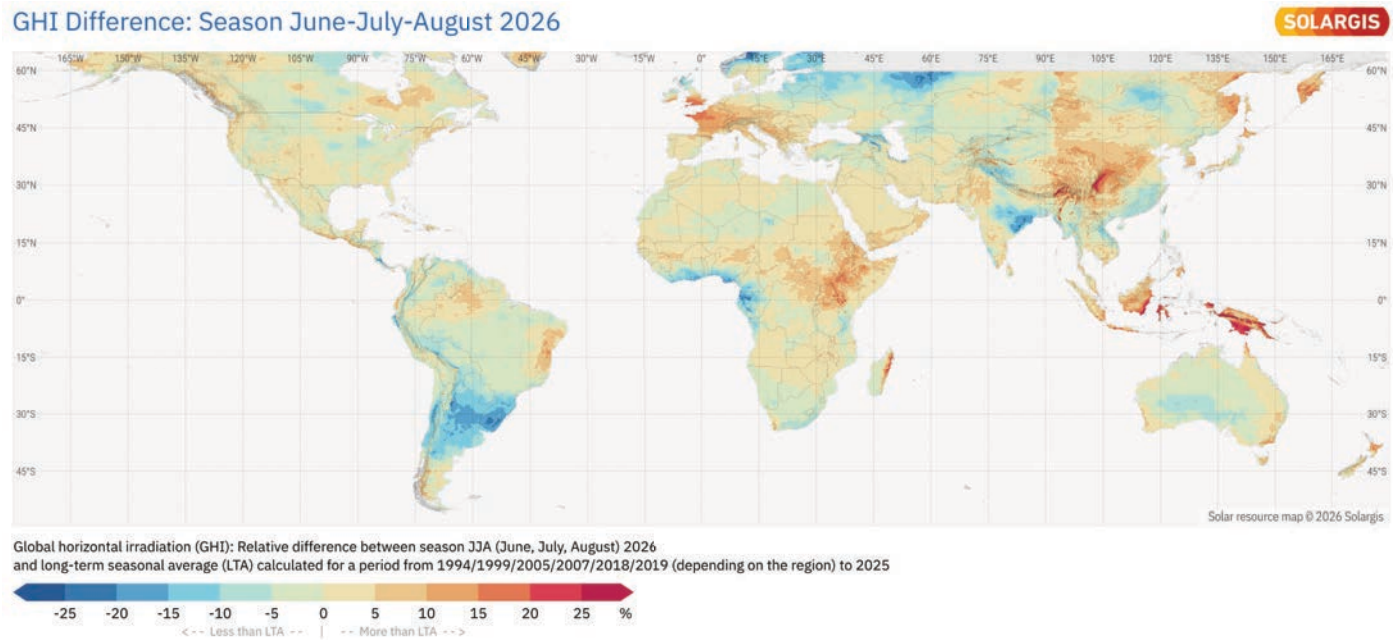


Figure 1. GHI difference between June-July-August 2026 season and long-term seasonal averages

is highly unusual, it becomes important to understand where it sits within the long-term distribution and whether recent observations suggest that assumptions should be reviewed.

Project owners should therefore treat natural phenomena like El Niño not as simple explanations, but as signals that need to be interpreted through high-resolution, site-specific data.

Heatwaves: more sunlight does not always mean more output

This is one of the most important lessons from summer 2026. In much of western and central Europe, July brought exceptional irradiation together with very high temperatures and prolonged dry conditions. According to Solargis' June-July-August analysis, southern England, Wales and Normandy recorded GHI anomalies exceeding +20%, while much of central Europe and the Balkans saw above-average irradiation in the range of +5% to +15%.

For PV power plants, this created a mixed performance picture.

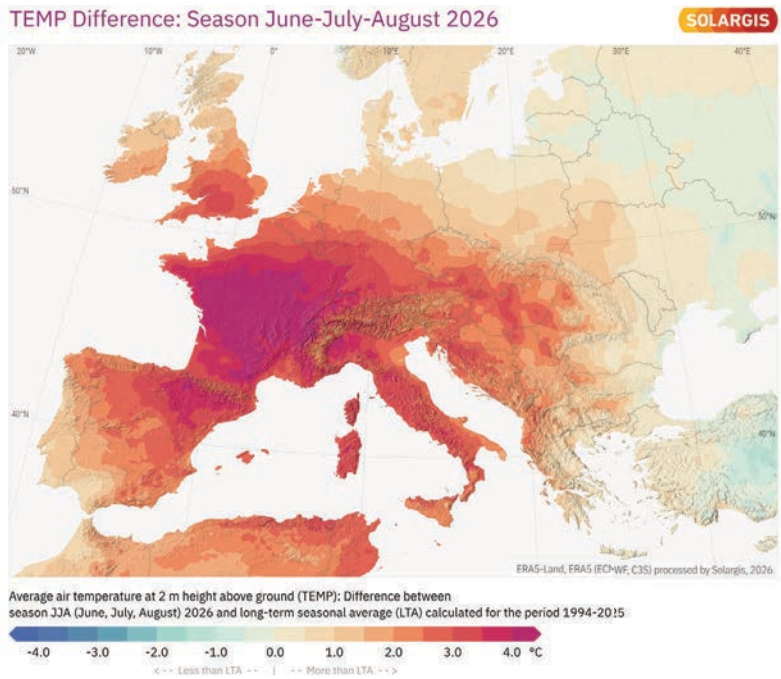
On the one hand, clearer skies increased the solar energy available at the surface. On the other hand, high temperatures reduced module efficiency. Crystalline silicon modules lose output as cell temperature rises above standard test conditions. Cell temperature itself depends on air temperature, irradiance, wind speed, mounting structure and local site conditions.

During heatwaves, PV plants may therefore produce strongly, but still underperform relative to the expected yield under the actual conditions. This distinction is important.

A power plant owner looking only at total energy generation may conclude that performance was good because production was high. But if irradiance was exceptionally high, the plant may still have produced less than it should have under the actual conditions. Conversely, a plant may appear to underperform against a long-term monthly budget, while in reality it performed correctly under a period of reduced resource.

High temperatures also affect equipment beyond the PV modules. Inverters can reduce output when internal or ambient temperatures exceed safe operating thresholds. This thermal derating protects equipment but reduces energy production. Transformer and cable losses also increase with temperature. In regions where grids are under pressure, high solar production during midday can also coincide with curtailment or market-related dispatch limitations.

Figure 2. Air temperatures in Europe measured at 2 metres above ground for the June-July-August 2026 season compared to LTA



Source: Solargis

The combination of heat and precipitation deficits is especially important. In the June-July-August season, many regions across western and central Europe recorded seasonal precipitation 50% below normal, with local deficits reaching as much as 80%.

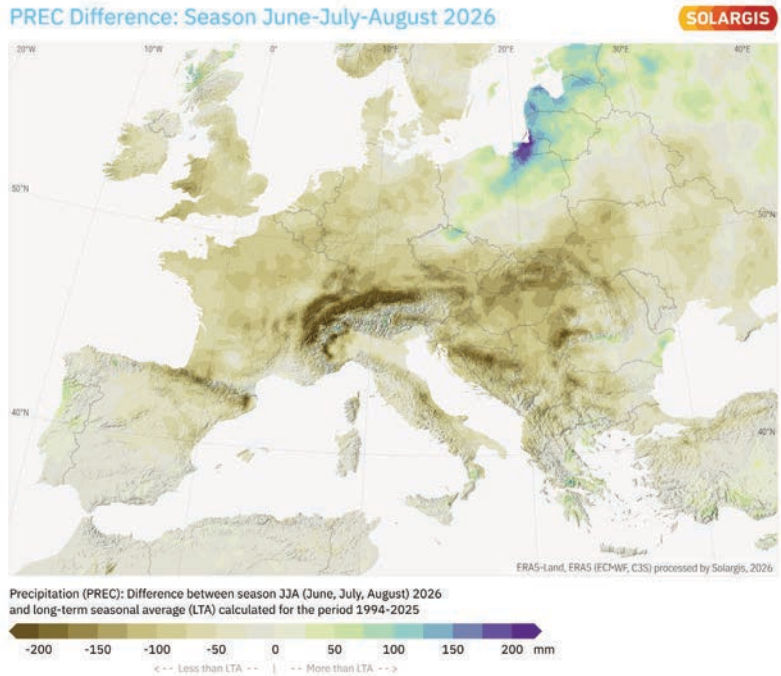
In central Europe, the persistent lack of rainfall reinforced already dry soil and vegetation conditions. Together with above-average temperatures and high solar irradiation, this dryness intensified heat stress and contributed to elevated wildfire risk.

This is why performance analysis during heatwaves requires more than a comparison between actual production and expected production. It needs temperature, wind, irradiance, soiling context, equipment status and grid information. Without these inputs, the explanation remains incomplete.

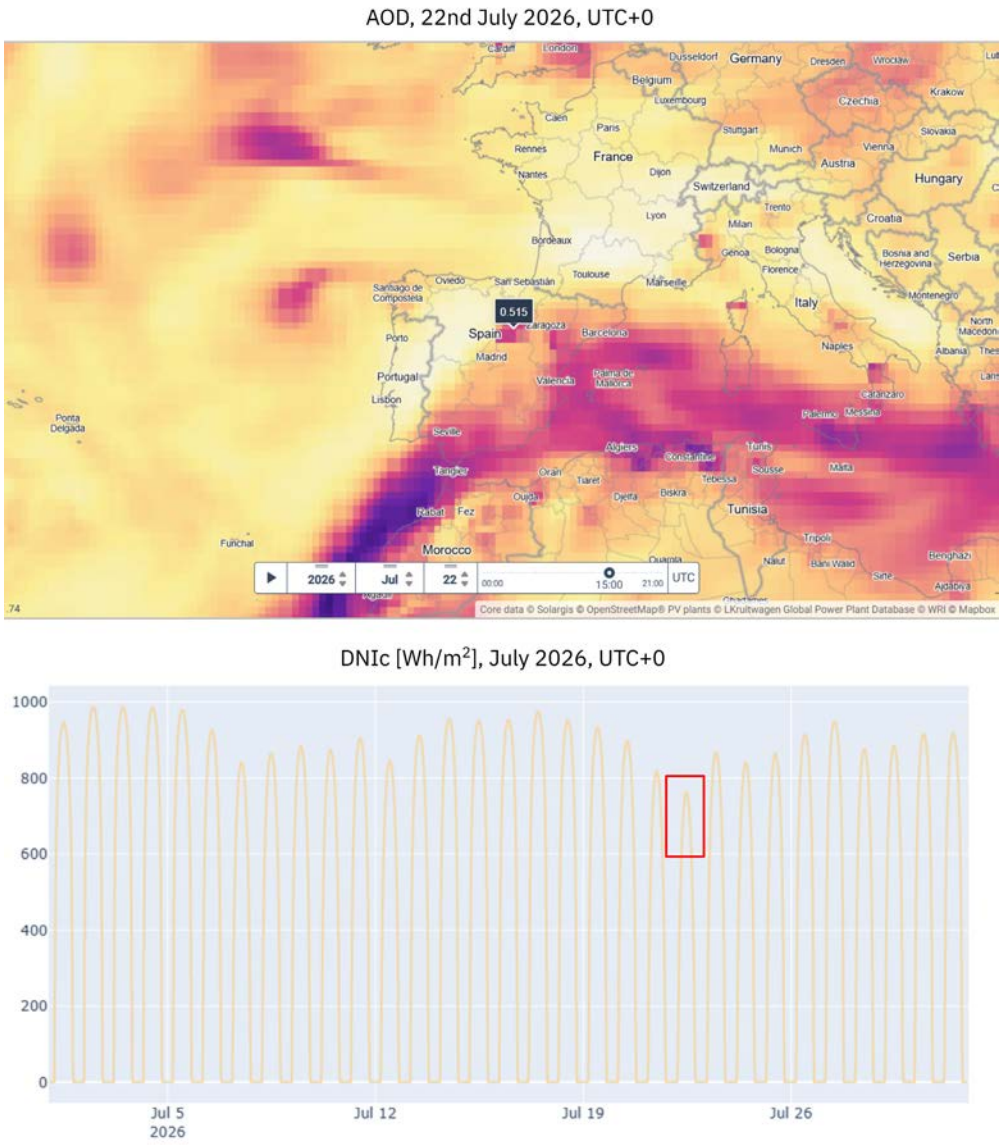
Wildfires' impact can travel far beyond the flames

In Europe, the 2026 summer season was also marked by severe wildfire activity. In France, for example, more than 70,000 hectares burned in July, marking

Figure 3. Much of Europe saw a persistent lack of rainfall over summer 2026 compared to historical averages between 1994 and 2025



Source: Solargis



Source: Solargis Livemaps

Figure 4. The AOD map shows a highly localised plume, which was likely connected to an active wildfire in Guadalajara

the country's largest wildfire season since 1949.

The direct impact of fire on PV assets can be severe, but relatively local. The wider performance issue is often smoke. Smoke plumes can travel long distances. A PV plant does not need to be located near a fire to experience its effect. If smoke passes overhead, it can reduce the irradiance reaching the surface and create short-term deviations from expected output.

This effect can be tracked using aerosol information, particularly Aerosol Optical Depth (AOD). Under clear-sky conditions, a rise in aerosol loading often appears as a reduction in direct normal irradiance, even when cloud cover is limited or absent.

Although the presence of aerosols coming from Sahara deserts can be quite common in Southern Europe during summer, an AOD map for the sample site near Soria, Spain, at 670nm on 22 July 2026, shows a highly localised plume covering the surrounding area, very likely connected to the active wildfire in Guadalajara.

This distinction matters because smoke-related losses can easily be misinterpreted.

If an asset manager sees a production drop on an apparently clear day, the first assumption may be an operational issue, soiling, inverter behaviour or a sensor problem. But if aerosol data shows a smoke plume passing over the site, part of the explanation may be resource-driven.

Wildfires can also increase soiling. Ash and fine particles may settle on PV modules and on-site sensors. This creates a second challenge. If the pyranometer is soiled, it may report lower irradiance than actually available to a clean reference surface. In that case, the site sensor itself becomes part of the problem, not a fully reliable benchmark.

This is one reason why independent irradiance and meteorological data are valuable during extreme events. On-site sensors are important, but they require maintenance, quality control and interpretation. Satellite-based and reanalysis data provide an external reference that can help identify whether a deviation was caused by the resource, the plant or the measurement system.

The solar eclipse: predictable does not mean irrelevant

The total solar eclipse of 12 August 2026 was different from heatwaves and wildfires. It was not a meteorological event, and it was fully predictable. Its timing, location and effect on irradiance could be calculated years in advance.

For PV plants in Spain, it was particularly relevant because of the country's high solar penetration. The path of totality crossed northern mainland Spain and extended toward the Balearic Islands. Other parts of Europe experienced the event as a partial eclipse.

Because the eclipse occurred close to sunset in Spain, the total energy loss was limited compared with an eclipse occurring near solar noon. However, from a performance reporting perspective, events such as solar eclipses still matter. They create a smooth and predictable dip in irradiance that needs to be attributed properly. Otherwise, they may appear as an unexplained deviation, an operational fault or a mismatch between measured and expected production.

This is a useful example of a wider principle. Not all unusual events are uncertain. Some can be predicted very precisely. But they still need to be included in the reporting chain.

What happens when July is extreme and August is closer to normal?

For long-term asset owners, one of the most important questions is how to interpret an extreme month within a longer season. A very sunny month can compensate for a cloudier one. Cooler periods can reduce thermal losses after a heatwave. Rainfall can reduce soiling after a dry spell.

But this does not mean that the extremes are irrelevant. Monthly or seasonal averages can hide important operational and financial signals.

A project may appear to be on track annually, while still experiencing specific losses during high-value periods. A production deficit during a high-price evening ramp, an intraday trading window or a grid-constrained period may have a larger financial impact than the same energy loss at another time.

This is particularly important as more PV projects are exposed to merchant pricing, curtailment, balancing markets and storage optimisation. The value of solar energy increasingly depends not only on how much is produced, but when it is produced and how predictable that production is. In this environment, extreme weather is not only a generation issue. It is a revenue and risk management issue.

Expected production has more than one meaning

Every performance report starts with a comparison between measured production and expected production. When the numbers are close, few questions are asked. When there is a gap, stakeholders need an explanation.

For investors and lenders, expected production often refers to the long-term P50 or another Pxx value used at financial close. Their question is: are we on track against the investment case?

For asset managers and performance engineers, expected production should also be recalculated for the specific reporting period using actual weather and resource conditions. Their question is: given the irradiance, temperature, wind, aerosols, precipitation and grid constraints that occurred this month, did the plant perform as it should?

Both perspectives are valid. But they require different benchmarks.

A power plant can be below its long-term budget because the month was cloudier than normal, while still performing correctly under actual conditions. A plant can exceed budget because the resource was unusually strong, while still underperforming technically. Without separating these effects, the report can be misleading.

This is why performance assessment needs to distinguish between resource-driven, plant-driven and grid-driven effects.

Resource-driven effects include irradiance, temperature, wind, aerosols, precipitation, snow and events such as eclipses. Plant-driven effects include availability, degradation, soiling, inverter behaviour, clipping and equipment losses. Grid-driven effects include curtailment, congestion, dispatch limitations and market-related constraints. Only when these categories are separated can project owners understand what really happened.

Data resolution matters more than before

Summer 2026 also showed why data quality, resolution and independence matter in PV performance assessment.

Monthly data can show whether a season was above or below normal. Daily data can identify heatwaves, cloudy periods or wildfire-related events. But hourly and sub-hourly data are needed to understand short-term ramps, inverter response, storage behaviour and intra-day market exposure.

Extreme weather also tests the reliability of measurement systems. During heatwaves, wildfires, dust events or soiling episodes, on-site sensors may be affected by dirt, local exposure issues, communication failures or delayed maintenance. This does not reduce the value of ground measurements, but it reinforces the need for quality control and independent comparison.

Satellite-based irradiance data, reanalysis meteorological data and aerosol models provide a consistent external reference. They help asset owners understand whether a production deviation was local or regional, whether neighbouring assets experienced similar conditions and whether the likely cause was irradiance, temperature, aerosols, wind, precipitation, plant behaviour or measurement issues.

As PV penetration increases, the industry needs to move beyond annual and monthly averages toward higher-resolution monitoring, simulation, forecasting and independent performance assessment.

From performance reporting to active risk management

As solar becomes a larger part of the power system, owners need performance intelligence that is more continuous, more granular and more closely connected to commercial decision-making.

Long-term resource data is still essential for project finance. But during operations, owners also need updated resource assessments, independent performance benchmarks, short-term forecasts and tools that can identify the reason behind deviations.

This is particularly important in a year influenced by El Niño. Climate patterns may increase the likelihood of certain regional anomalies, but they do not remove the need for local analysis. A project owner needs to know what happened at the site, how unusual it was, whether it affected the PV plant's performance and whether similar conditions may continue.

In this sense, solar resource intelligence is becoming part of active asset management.

What project owners should take from summer 2026

The main lesson from summer 2026 is not that PV plants are unprepared for extreme weather. Most modern assets are designed to operate through heatwaves, smoke events, storms and short-term irradiance dips.

The real lesson is that performance reporting and decision-making need to become more precise. Asset owners need to understand whether a production gap was caused by resource variability, plant behaviour, grid constraints, or measurement issues. They also need to know whether an extreme month was an isolated event or part of a broader seasonal pattern.

This understanding must then translate into practical decisions: investor reporting, model updates, maintenance planning, forecasting, battery operation and financial risk management.

Extreme weather and climate variability will remain part of solar generation. The goal is not to treat every anomaly as a crisis, but to make anomalies explainable.

With high-resolution irradiance data, reliable meteorological inputs, aerosol information, validated models, independent performance benchmarks and accurate forecasting, unusual events can be understood in context. Solar generation will always depend on the weather. But the quality of decisions around solar assets depends on how well we understand it. ■

Author



Pablo Caballero is an industrial engineer with extensive experience in the renewable energy and software development sectors. He specialises in technical writing and is driven by a passion for bridging gaps between audiences, technology and business. With a diverse background, he is dedicated to promoting sustainability ideas and education in STEM fields.

Lost bypass diodes in PV modules: a hidden fire risk—and how to find it

Component performance | Intertek CEA's Jörg Althaus explains what lost bypass diodes are, why they are so difficult to detect and how they can be identified in the field without removing a single module



Credit: Sikwe Scarter

Solar plants are routinely inspected by drone, assessed by IV curve tracer and monitored by SCADA. Yet one of the most dangerous defects in a modern PV module—a lost bypass diode—remains completely invisible to all of these methods. It causes no yield loss in normal operation, leaves no thermal signature in standard IR surveys and can sit undetected in an installed plant for years, waiting for the right shading event to trigger a fire.

This article explains what lost bypass diodes are, why they are so difficult to detect, how they differ from the better-known lost substring defect and how Intertek CEA identifies them in the field—efficiently, safely and without removing a single module.

Modern module architecture and where the problem originates

The vast majority of modules manufactured today use what is known as butterfly architecture. In a typical 120-cell or 144-cell module (see Figure 1 and Figure 2), cells are arranged in six substrings—three on the top half of the module and three on the bottom—connected in parallel pairs. Each parallel pair shares one junction box containing one bypass diode, giving three junction boxes and three bypass diodes (illustrated by the arrow symbol in Figure 1 and Figure 2) per module in total.

Lost bypass diodes are silent, difficult to detect and dangerous

This design was adopted by manufacturers to reduce material costs by using shorter busbars, smaller junction boxes and simpler internal wiring. It is efficient

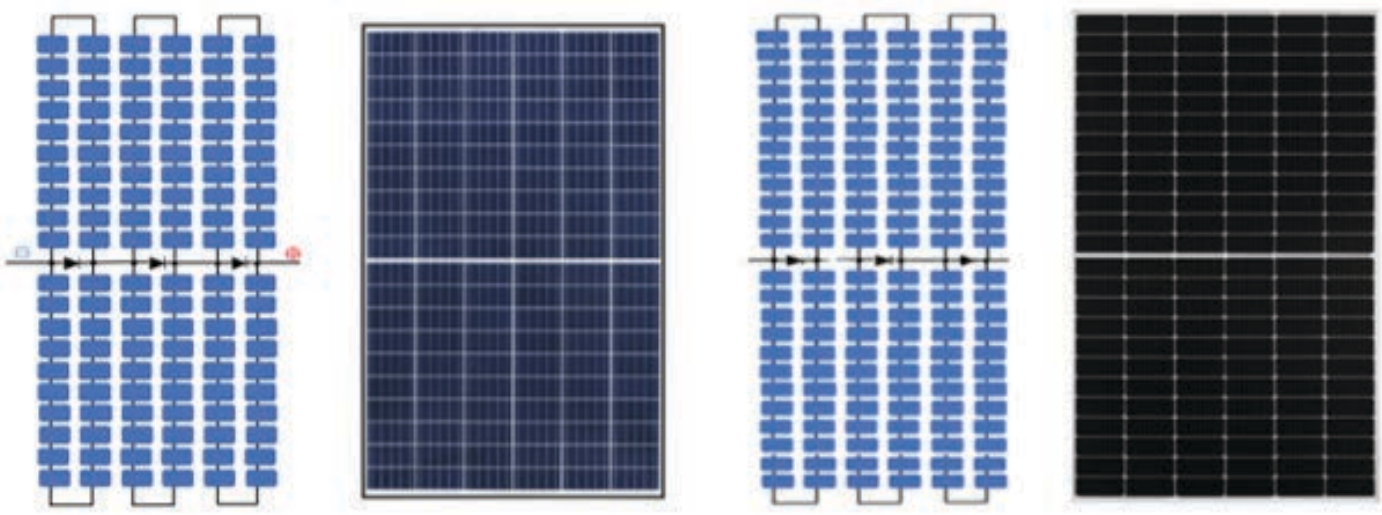


Figure 1 (left). 120-cell butterfly architecture

Figure 2 (right). 144-cell butterfly architecture

and now essentially universal. However, it concentrates the bypass diode function into just three components per module, and the way those diodes are connected introduces a vulnerability that manufacturers have not yet systematically addressed.

The soldering connections between the cell string ribbons and the junction box are made in the module factory and checked by an AI-assisted visual camera system. There typically is no electrical or thermal verification of those solder joints in the production line. A joint that looks acceptable to a camera may have no actual electrical continuity—and if the cell string ribbon on that junction box is not electrically connected to the diode, the module will leave the factory with a lost bypass diode.

It will perform normally in testing. It will pass every standard quality check. And it will continue to perform normally in the field—until it is shaded.

Lost substring versus lost bypass diode

Before explaining what happens with a lost bypass diode, it is worth distinguishing it from a related but different defect: the lost substring.

A lost substring occurs when there is a contact problem in the junction box that causes an entire double substring to be permanently disconnected from the circuit. The bypass diode activates continuously to route current around it. The effect is immediately measurable: the module loses approximately one-third of its power output and voltage and shows a permanently elevated, uniform temperature across the disconnected substring area in any IR survey. It appears in aerial drone reports as a "sub-module anomaly" or "single/double bypass".

It is detectable, reportable and, while it represents a yield loss, the affected substring is already in open circuit and presents no additional risk during shading because no further deterioration is possible.

A lost bypass diode is categorically different and considerably more dangerous. The module performs entirely normally—full power, no IR anomaly and no measurable deviation of any kind. The defect is silent.

The circuit is simply not connected to the bypass diode. In normal unshaded operation this matters not at all, because bypass diodes are reverse-biased and inactive anyway. The problem only materialises when the substring that diode is supposed to protect becomes shaded. Table 1 indicates which effect each failure type has on the module's performance under shading.

What happens when a module with a lost bypass diode is shaded

When a substring is shaded and the bypass diode is functional, the diode activates, conducts the string current around the shaded cells and the module continues operating safely. When the bypass diode is not connected, there is no such path (see Figure 3). The full string current is instead forced through the shaded cells in reverse bias.

As reverse voltage builds across the shaded cells, p/n-junction breakdown is reached. The resulting avalanche effect causes a sudden surge in current through the affected cells, creating extreme localised power dissipation. Temperatures exceeding 500 degrees

Scenario	How does the module perform during normal operation?	IR Signature	What happens during module shading
Soldering okay	Performs as expected	None	Bypass diode activates to protect cells
Lost bypass diode	Performs as expected	None	Bypass diode does not activate resulting in high temperature module hotspot and permanent cell damage
Lost substring	Power and voltage reduced by one-third	Elevated uniform temperature in one-third of the module. Also called a sub-module anomaly in many aerial IR reports	Substring is already in open circuit. No change or risk to module

Table 1. Implications for module performance—three-scenario comparison

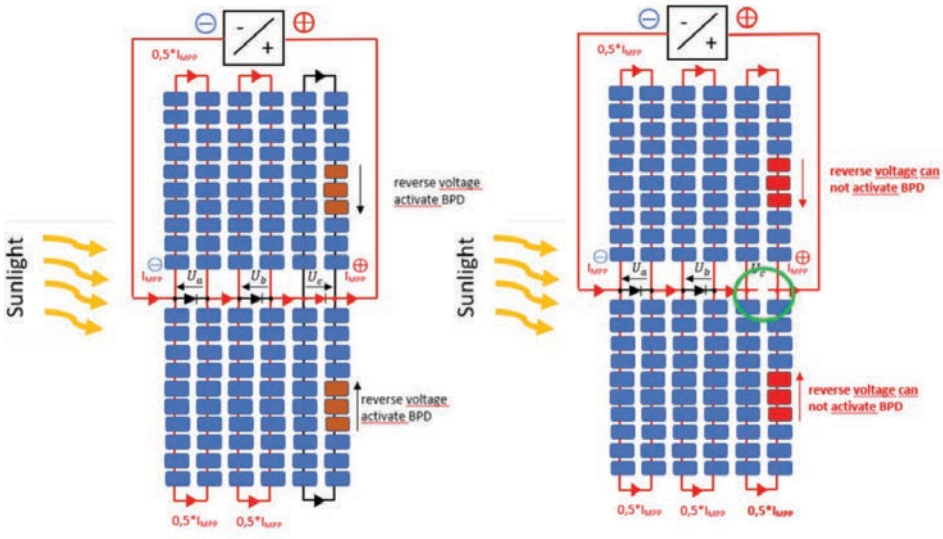


Figure 3. Functional bypass diode under shading versus a lost bypass diode under shading

Celsius have been recorded.

This localised heating, if sustained—for example through row-to-row shading at low sun angles, or shading from vegetation or soiling—leads to permanent thermal breakdown of the p/n-junctions. The damage is irreversible: those cells will generate heat every time the module produces power, even after the shading event has passed.

Over time this escalates further. Encapsulation materials melt, glass cracks, burn marks develop and in the most severe cases arcing initiates broader thermal events. Bush fires have been attributed to this failure mode. Real-world cases documented by Intertek CEA include glass-foil modules in the Netherlands in 2024 and bifacial modules in France in 2023 (Figure 4), both with confirmed lost bypass diodes as root cause.

Critically, the shading required to trigger this chain of events is not exceptional. Row-to-row shading at low winter sun angles, bird droppings, a patch of snow or vegetation growth at the module edge is sufficient. Every plant experiences these conditions routinely.

Why standard inspections cannot find this

Lost bypass diodes are invisible to every conventional field measurement method. This is not a question of inspection quality—it is a fundamental consequence of how the defect behaves. In full sunlight, a module with a lost bypass diode is electrically indistinguishable from a healthy module. Flash testing, EL imaging, IV curve analysis and aerial IR thermography all return normal results. There is simply no detectable signature under normal operating conditions.

It has been suggested that lost bypass diodes can be found in the field by manually shading individual substrings and using a thermal camera to check whether the expected bypass diode activation signature appears. While this works in principle, it is impractical at any meaningful scale: it requires suitable irradiance, physical access to each module, manual shading of individual substrings one by one and a wait for thermal equilibrium before each reading.

Across a plant of tens of megawatts, it is not a viable methodology. It also requires prior knowledge of which modules to test—which rather defeats the purpose of a screening campaign.

There is a better approach.

Intertek CEA's field detection method: fast, non-invasive and scalable

Intertek CEA detects lost bypass diodes using an electrical method that requires no shading, no module removal and no disruption to daytime plant operation. Testing is carried out at night, with strings temporarily disconnected from the inverter.

At string level, an entire string is screened in minutes using a portable power supply and a controlled electrical stimulus. The result is immediate

Figure 4. Front and rear view of module from French installation with row-to-row shading that caused burn marks and glass breakage. Notably the junction box is not affected as the diode is not connected and no heating is caused inside the junction box



and unambiguous: the test equipment directly indicates whether all bypass diodes in the string are connected, and if not, how many substrings are affected. No interpretation is required, no weather conditions need to be met and no modules are touched.

For any string where a problem is identified, we move to module-level localisation. The same controlled stimulus induces a safe, detectable thermal signature in the affected cells within seconds, captured using a handheld IR camera or IR drone. The exact module and the specific substring are identified and documented, without opening a single junction box.

Using this method, a two-person team can inspect approximately 4-5MW of installed capacity per night. Results are documented with string ID, module position and IR imagery suitable for warranty claim submission.

The factory gap—and a simple fix

The most efficient point at which to eliminate lost bypass diodes is before modules leave the factory. Every manufacturer already performs a hi-pot or insulation test. The same test equipment often already has an in-built diode test functionality which is just not being utilised. Alternatively, EL testing carried out on 100% of production—a test that injects current through the module—provides another option to implement this in-line control step. The EL tester is already connected to the module's DC terminals on every single module produced.

A simple modification to that existing test step—specifically, a brief reversal of injection polarity—would be sufficient to identify every module where a bypass diode has no electrical connection. If the polarity is reversed and current flows, all three diodes are connected. If it does not, at least one diode is uncontacted. The check takes seconds, requires no additional hardware and produces a clear pass/fail result.

The reason this is not yet universal practice is essentially one of economics and probability. Lost bypass diode failure rates per module are relatively low, and manufacturers have been reluctant to add any production step—however brief—to a high-throughput line for a low-frequency defect. When the alternative is a fire at a customer's plant, that calculation deserves to be revisited.

It is important to note what this factory test would and would not catch. It would reliably identify whether the complete module–diode path is closed and reliably flag whether a diode is not able to do its job.

It would however still fail to detect marginal or weakened solder joints that have some electrical contact at manufacture but may degrade and fail in service over time. Those cases can, for now, only be identified through field testing. The simple diode check is nonetheless a meaningful and currently absent first filter, and its absence from production lines across the industry represents a gap in PV quality assurance that has real consequences.

In fact, the safety standards IEC 61730-2 and UL 61730-2 already list the diode test in their respective annexes. However, they allow the test to be performed on the junction box prior to assembly. This can identify a diode that was not properly soldered within the junction box, but it does not determine whether the cell string was connected correctly. IEC TC82 the technical committee developing PV standards, is currently revising this standard, with an update expected in 2027.

For buyers who want assurance between factory gate and energisation, Intertek CEA already integrates lost bypass diode screening into its standard post-shipment EL inspection service. This is conducted on an AQL-based sample, consistent with normal pre-installation quality assurance practice, providing documented evidence of bypass diode connectivity status before modules are installed.

When to test

Lost bypass diode testing is relevant across the asset lifecycle. Pre-COD acceptance testing establishes a clean baseline and protects the buyer's warranty position—any module found defective at that stage was defective when delivered.

For plants already in operation, a sampling campaign across representative strings can characterise the actual risk level of a specific batch rather than leaving it unquantified. Following any hot-spot fire or arc event, testing the remaining strings from the same production batch should be mandatory before the plant returns to normal operation. For M&A, refinancing or insurance assessments, lost bypass diode testing provides a documented answer to a safety question that no other standard inspection method can address.

Plants using TOPCon cells warrant particular attention. Research has shown that TOPCon cells have a significantly higher reverse breakdown voltage than PERC or Al-back-surface-field cells, meaning that under unprotected shading conditions the shaded cells must absorb considerably more energy before avalanche breakdown occurs—resulting in higher peak hotspot temperatures and a greater risk of irreversible thermal damage [1]. For these portfolios, functional bypass diode protection is not optional.

Conclusion

Lost bypass diodes are a manufacturing defect that is present in an unknown but non-trivial share of installed modules worldwide. They are silent in normal operation, undetectable by any standard inspection method and dangerous the first time ordinary shading conditions occur. They may affect entire production batches, and the root cause lies in a factory process that has no electrical verification step.

Increased quality control on diode connections in the factories is possible, and detection in the field is achievable today—quickly, non-invasively and at scale. The technical barrier to addressing this risk is low. The consequences of not addressing it are not. ■

Reference

[1] Jaeckel, B. et al., "Characterisation and analysis of reverse breakdown voltage onset of solar cells with different cell architectures," EPJ Photovoltaics, Vol. 17, 2026. DOI: 10.1051/epjpv/2025024

Author



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Avoiding the hidden cost of retrofitting battery storage to solar PV projects

Hybridisation | As the business case for co-locating batteries with solar PV builds, how best can solar developers plan to hybridise their assets? Stem's Sam Kuhlwein reports on the hidden costs of retrofitting batteries to solar PV projects



Credit: Stem

Solar developers have spent the past three years watching the same pattern repeat across nearly every major market: a plant goes into operation as standalone solar, and within a few years its owner is back at the site, adding batteries.

Global battery energy storage deployment grew 53% year-on-year in 2024, passing 200GWh for the first time, while battery costs fell roughly 40% over the same period, which has translated to new storage deployments in a number of leading markets.

In the US, more than half of the capacity in the national solar interconnection queue is now paired with battery storage, a share that reaches 98% in California's grid operator territory. In Australia, developers behind 2.4GW of existing standalone solar have started or completed the process of retrofitting battery storage onto plants that hadn't been built with it in mind.

The economic logic is straightforward: battery energy storage systems (BESS) let a solar asset shift generation away from the hours when it is worth least, which in a growing number of markets now includes hours when wholesale prices turn negative and a plant has to pay a penalty to export to the grid, and into the hours when it is most valuable. The addition of batteries also allows for participation in capacity and ancillary service markets and reduces the amount of otherwise free solar energy that gets curtailed.

Hybridisation is becoming increasingly common for utility-scale solar, whether storage is added at construction or years into operation

But the operational and technical reality of adding storage to a plant that was not designed for it is far less straightforward, and it's where a great many hybridisation projects get behind schedule and lose months of performance which they may never recover.

This is not an argument for building battery storage on day one of every project. Standalone solar remains the right call for plenty of sites, including those with long-term fixed-price power purchase agreements (PPAs) that don't reward dispatchability, or those financed under structures where adding a second asset class later would complicate the capital stack.

Rather, it's an argument for making one class of decision – relating to the control architecture – as though storage is coming eventually; for a growing share of the market it is, and that decision costs far less to specify up front than to retrofit later.

The coordination problem

The root of most hybridisation headaches is architectural, not commercial. A solar-plus-storage facility is rarely one plant in control terms, and the number of controllers it needs depends on how the site is configured.

At a true hybrid site, solar and storage operate as a single asset, taking setpoints referenced to the point of interconnection (POI). On a co-located site, the two sit behind a single POI but receive separate dispatch signals, which means two plant controllers running in parallel beneath a top-level controller that coordinates them. Either configuration asks several distinct control systems to behave as one, and how cleanly they manage that is largely determined at design time.

Substation controls are responsible for operating substation equipment safely, which means medium-voltage transformers, breakers, protection relays and the like. The plant controller, not the substation, is what monitors the point of interconnection and provides frequency and voltage support when the grid calls for it, within the limits set out in the interconnection agreement.

PV controls optimise for irradiance, managing inverter setpoints and string-level performance. At the container level, the battery management system (BMS) prioritises cell protection and cycle life, managing charge and discharge rates, thermal conditions and state of charge. It is worth being precise about this one: the BMS is a container-level control system, not an energy management system (EMS).

Each of these systems has historically been supplied by a different vendor, with its own control philosophy and communication protocol, and they have typically been left to negotiate with each other in what industry engineers sometimes call a demilitarised zone: a local network where responsibility for coordination is unclear and where plant operators often absorb the cost of stitching the systems together.



Credit: Stem

Fragmented multivendor control systems can become costly once battery storage is added to a PV project retrospectively

For a standalone solar plant, this fragmentation is a manageable inconvenience. Add a battery to that architecture after the fact, however, and the cracks show quickly. Battery vendors optimise for storage dispatch and are not built to understand generation forecasting, whereas solar vendors optimise for irradiance capture and are not built to understand state-of-charge constraints. Neither was designed to deliver the kind of sub-second, coordinated response that grid operators increasingly require for frequency and voltage services from a hybrid resource.

The result, in practice, shows up in three ways: integration testing that stretches from a few weeks to several months, coordination gaps between the systems that persist well after commercial operation begins and control-layer latency that disqualifies otherwise capable hardware from premium grid service markets. Assets fail fast frequency response qualifications surprisingly often, not because the batteries or inverters cannot physically respond quickly enough, but because the handoffs between separate control systems are too slow.

Determining readiness for hybridisation

Solving the coordination problem described above at the retrofit stage is possible, and how expensive it turns out to be depends heavily on the original architecture. As noted above, it costs far less to specify the right architecture at the outset than to retrofit it later, though what "getting it right" means depends on where a plant is in its lifecycle.

The Hungary case study below shows what these decisions look like when they are made correctly from the start. For a project still in development, it means making the following three decisions, within the control and coordination level, well from the outset. For a plant already in operation, it means auditing which of these decisions were already locked in, since that determines the actual retrofit cost and timeline.

Control architecture

This is the decision with the largest long-term consequences, and the one most squarely within the control layer. A plant built on a unified energy management, power plant control and SCADA platform—capable of coordinating generation, battery storage and grid compliance through a single logical system—can generally absorb a battery addition as a software and hardware extension rather than a rebuild.

A plant built on separate, siloed controllers for each piece of equipment is building in the multivendor coordination problem described above, and it will surface the moment storage is added, if not before. It also shows up in a more basic way: traditional PV plant

controllers were built to optimise solar harvest without understanding battery constraints, and battery management systems were built to treat solar generation as an external variable they cannot influence. Neither was designed to deliver grid services, such as combined ramp-rate control or voltage ride-through, that require real-time coordination between both resources rather than sequential handoffs between two separate systems.

Open, standards-based communication protocols

These operate at different layers and serve different purposes, so it is worth being precise about which protocol is doing what. Modbus, OPC-UA and IEC 61850 sit closer to the equipment layer, and standardising on them, rather than a proprietary vendor-specific interface, is what actually preserves the ability to select the best available battery, inverter or optimisation software if and when storage is added. DNP3 is more commonly used for utility telemetry and reporting compliance; it is a legitimate protocol to standardise on for that reason, but doing so does not, on its own, expand equipment choice the way the others do.

Deferred duration sizing

Battery duration is one of the highest-stakes sizing decisions in a hybrid project, and it is better made with real operating data than with a development-stage forecast. A plant with two or three years of standalone operating history has an actual curtailment and pricing profile specific to its interconnection point, generated by the same monitoring and EMS platform running the solar side, which is a far better basis for choosing between a 2-hour and a 4-hour system than a proforma assumption made before the plant was energised.

Designing the control architecture to be duration-agnostic from the outset, rather than assuming a fixed storage size at the planning stage, preserves the option to size that system using real data when the time comes. Battery chemistry selection involves a separate set of supply chain, safety and commercial considerations outside the scope of this piece.

Proof in practice: Hybridising two operating plants in Hungary

The clearest illustration of what control-layer planning looks like in practice comes from Central Europe. In 2025 and 2026, the Solarmarkt Group, a Hungarian renewable energy company, brought two 60MWp utility-scale solar plants into operation at Szihalom and Hódmezővásárhely, using power plant control (PPC) software supplied by Stem, built on architecture designed with future hybridisation in mind from the outset.

That decision paid off sooner than many similar projects manage. In August, the Solarmarkt Group, as part of a five-year deal with engineering, procurement and construction (EPC) partner Pannonwatt, announced plans to add a 40MW/80MWh BESS to each site, extending the existing control platform across the new storage assets rather than replacing it.

The technical detail that matters most for other developers is what did not need to change. Because the original PPC was specified as a hybrid-ready platform, adding battery storage did not require replacing the existing controls foundation; the same software and controls platform simply extends across the new battery systems at each site.

The plants will use their existing platform to coordinate solar generation, battery dispatch, grid constraints and market dispatch instructions as a single system, while maintaining compliance with distribution-system operator E.ON's technical requirements. Commercially, the initial strategy targets participation in Hungary's automatic Frequency Restoration Reserve market, with the architecture designed to support Frequency Containment Reserve services and cross-border value-stacking as Central and Eastern European electricity markets become more interconnected.

A global pattern with market-specific triggers

The mechanism differs by market, but the underlying pattern holds everywhere. In the US, the trigger is largely interconnection economics: with queues for new grid connections running into years in the most congested regions, adding battery storage at an existing point of interconnection is often the fastest way to add dispatchable capacity

In Australia, the trigger is a mix of curtailment economics and time-shifting value, as operators move cheap midday solar generation into the higher-priced evening peak. In Central and Eastern Europe, the trigger is the maturing ancillary services market and the prospect of cross-border trading as regional grids become more interconnected.

What is consistent across all three is the lesson for anyone planning a new solar project or evaluating an existing one today: the decision to build battery storage now or later is genuinely optional, but the decision to design the control layer as though storage might come later shouldn't be.

A planning checklist

For developers evaluating a project currently in development, three questions do most of the work on the control-layer side:

1. Does the control platform coordinate generation and storage as one logical system, or would adding a battery mean stitching together a second, separately sourced control system?
2. Are the communication protocols open and standards-based at the equipment layer, preserving choice of battery, inverter, and software later?
3. Has the duration-sizing decision been left open, so it can be made using real operating data rather than locked in at the development stage?

For an asset already in operation, the equivalent audit looks backward rather than forward:

1. Does the existing control platform already coordinate generation and storage as one logical system, or would adding a battery mean stitching together a second, separately sourced control system?
2. Are the existing communication protocols at the equipment layer open and standards-based, or would retrofitting mean working within a proprietary interface?

None of these questions require a battery to be installed today, but all three determine whether adding one later is a software extension or a more disruptive rebuild of the control system specifically. ■

Author



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From finding viable land to de-risking projects: the evolving role of PV mapping software

Mapping | Evan Sarkisian, US general manager of Glint Solar, examines how mapping software has changed to tackle the challenges of solar and storage project site selection



Credit: Glint Solar.

A parcel with enough acreage, relatively flat terrain and a substation nearby can look ideal on a map. Yet that same parcel may be unsuitable once local setbacks are applied, the grid connection route is examined or a neighbouring home realises how loud a utility-scale battery can be. Finding land is rarely the main difficulty. The challenge is finding a site that meets the requirements of a viable project.

This has changed what solar and storage developers need from mapping software. Developers have long used maps to understand where they could build. Increasingly, they need to establish what they could build, which uncertainties to investigate and how the design would affect the people around it. They also need to explore changes without joining a queue for specialist input every time.

In my conversations with US solar and storage developers, questions about interconnection, permitting and community acceptance repeatedly become questions about location. These are different disciplines, but their consequences meet on the same site. Mapping provides a way to examine them together before committing more time and capital.

From general purpose tools to specialist software

Solar has a history of adapting tools and materials developed for other industries, then developing its own as demand grows. Its early reliance on semiconductor-industry silicon supplies is one example. Software has followed a similar pattern.

General-purpose geographic information systems, including ArcGIS and QGIS, provide powerful capabilities for managing and analysing spatial data. Alongside Google Earth, computer-aided design (CAD) and spreadsheets, they remain important today. The difficulty is coordinating work across them. Specialists may hold different parts of the project information, while developers wait for updated maps or layouts before making their next decision.

Purpose-built screening and preliminary design tools have made site selection a more tailored process

In a familiar workflow, a geographic information system (GIS) specialist assembles layers and identifies potentially suitable land. Boundaries pass to an engineering team for a layout. The developer coordinates requests and waits for answers before deciding whether the opportunity warrants further work.

Purpose-built screening and preliminary design tools have changed who can answer some of those questions, and when. Development staff can explore candidate parcels, apply exclusions and compare indicative layouts without commissioning detailed engineering for every possibility. Specialists can then concentrate on the opportunities and uncertainties that require their expertise.

Early tools brought relevant information together. Developers can now assess usable land and potential capacity, then test changes to site boundaries and layouts themselves. General-purpose GIS and CAD remain valuable for the detailed analysis that follows.

How site selection challenges have changed

When developers describe a shortage of good sites, acreage is often only part of the problem. Suitable land also needs a plausible grid connection and a permitting pathway. The owner must be willing to lease or sell, and the proposed design needs to address local concerns. Finding those conditions in the same place is the difficulty.

Interconnection is a good example. Berkeley Lab's 2026 Queued Up report found that, in regions with available data, projects built in 2025 had a median duration of more than five years between interconnection request and commercial operation. Only 13% of the capacity entering the transmission queues between 2000 and 2020 had reached operation by the end of 2025 [1].

These are transmission-queue figures, not a measure of every distributed solar project, but they underline the importance of investigating connection risk early.

Local conditions matter alongside the grid. Berkeley Lab's developer survey, published in 2024, identified local ordinances, interconnection and community opposition as leading causes of utility-scale wind and solar project cancellations [2]. A parcel's apparent suitability can change substantially once local requirements are translated into its actual boundaries.

Adding a battery energy storage system (BESS) adds further design questions. Its smaller land requirement does not remove the need to consider nearby homes, equipment noise, access and the surrounding environment. Two parcels with similar acreage and grid proximity may support very different projects.

Mapping cannot resolve financing, procurement or national policy obstacles. It can show how location-dependent constraints interact, allowing developers to explore alternatives earlier rather than discover their combined effect through successive specialist reviews.

Screening for the right project

Before screening sites, developers need to define the project they are seeking. That means deciding on the technology and target capacity, identifying the market and connection requirements and establishing the development risks that they can accept. A community solar project, a large transmission-connected array and a standalone battery should not inherit the same screening criteria.

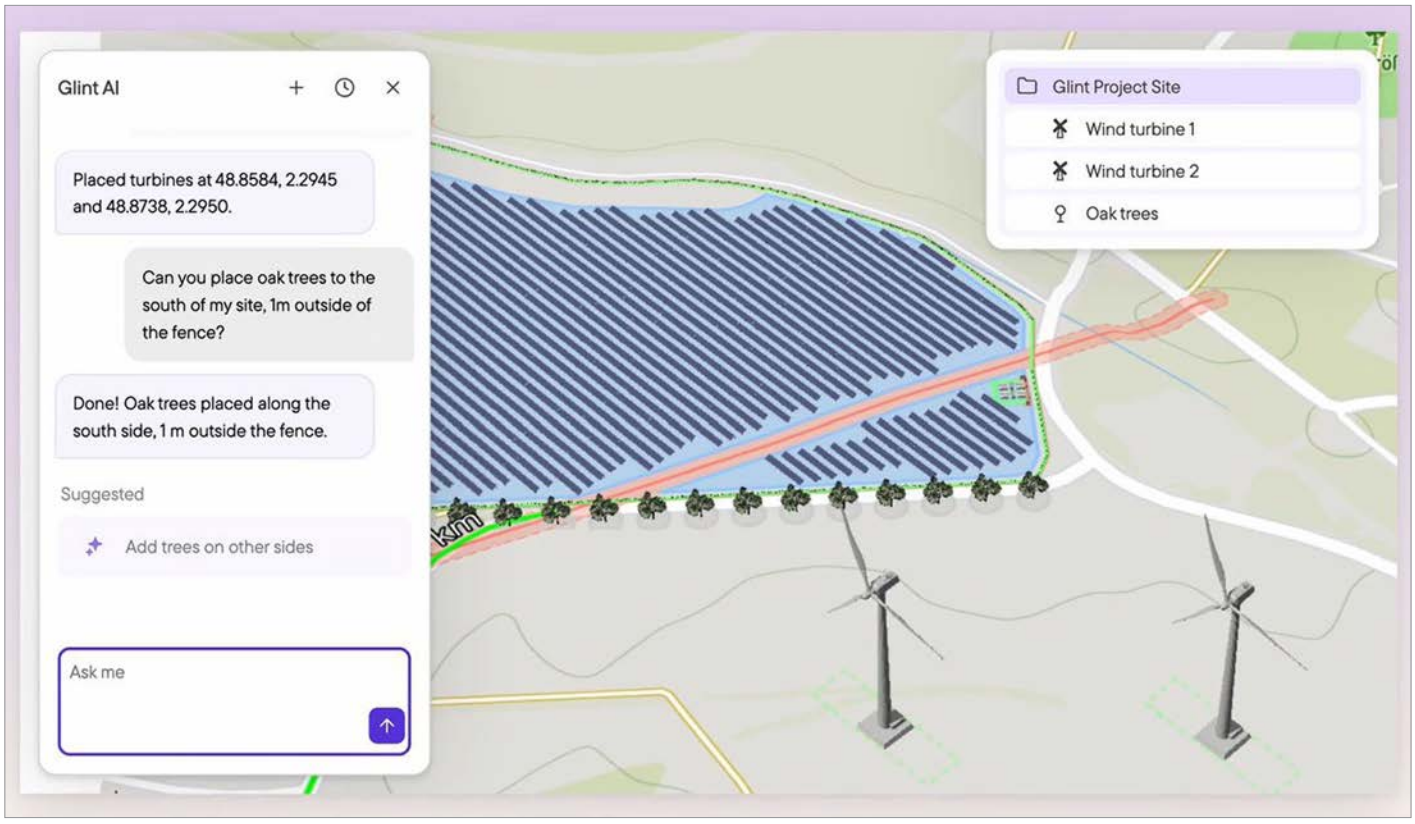
Previously, a regional search often meant assembling grid, parcel, terrain and planning information across separate systems. Mapping tools can now bring those layers into a repeatable screening process, so developers can adjust criteria and compare candidate areas themselves. Ownership information then supports targeted outreach once a shortlist is established.

Grid proximity is only a starting point. A mapped line does not give you the right to connect, and a nearby substation does not establish accessible capacity. Utility territory, infrastructure ownership and the feasibility of the connection route all need checking.

Developers face grid challenges at both distribution and transmission level. For smaller projects connecting to distribution networks, utility hosting-capacity maps can indicate where a connection might be possible.

However, not all utilities publish them, and the maps cannot confirm whether a particular project can connect. For larger projects connecting to transmission networks, developers often need to piece together information from different software tools, consultants and interconnection studies. Neither has it easy.

Mapping software can bring this grid information together with parcel boundaries, setbacks and other land restrictions. Developers can then compare sites without repeatedly gathering the same information from separate sources.



Sophisticated mapping software allows developers to explore design changes and visual screening options during early project planning

Credit: Glint Solar

Avoiding jurisdictions with high development risk

Community risk starts before a layout is drawn. Developers have traditionally maintained their own databases of local authorities having jurisdiction or relied on staff who knew whom to call in each county.

Shared ordinance and project-history information can now help identify moratoria, restrictive rules or a pattern of rejected applications before extensive site work begins. Sources still need checking: a previous rejection does not establish that every proposal will fail.

Connecting site selection with preliminary design

Once candidate land is identified, gross acreage is an inadequate basis for deciding what it can accommodate. Setbacks, wetlands, slope, access routes and other restrictions will in most cases leave a buildable area that is smaller and more fragmented than the parcel outline suggests.

A preliminary design helps establish whether the usable area can accommodate the intended capacity and whether its shape suits the layout. Developers can test the effect of moving an access road, then take the more promising options to engineering.

Consider a hypothetical solar parcel with a wetland crossing its centre and homes along one boundary. Once the wetland and the space needed to screen the project from nearby homes are excluded, there may not be enough land left for the planned capacity.

The developer then waits for a GIS specialist to redraw the buildable area and an engineer to produce a revised layout. A later ALTA/NSPS land title survey could reveal further restrictions, such as an easement across the site or a problem with access. The developer may then need to secure additional land, commission a survey of that parcel and request another layout. Wetland assessments and title surveys are separate investigations, but findings from either can send the project back through the same steps.

With the relevant data and layout settings loaded, developers can instead compare indicative scenarios in seconds: reduce capacity, move the buffer or test adjacent land. That gives them a basis for deciding which alternative deserves specialist attention. It cannot prevent every late survey finding, but it can reduce the repeated handoffs needed to understand its implications.

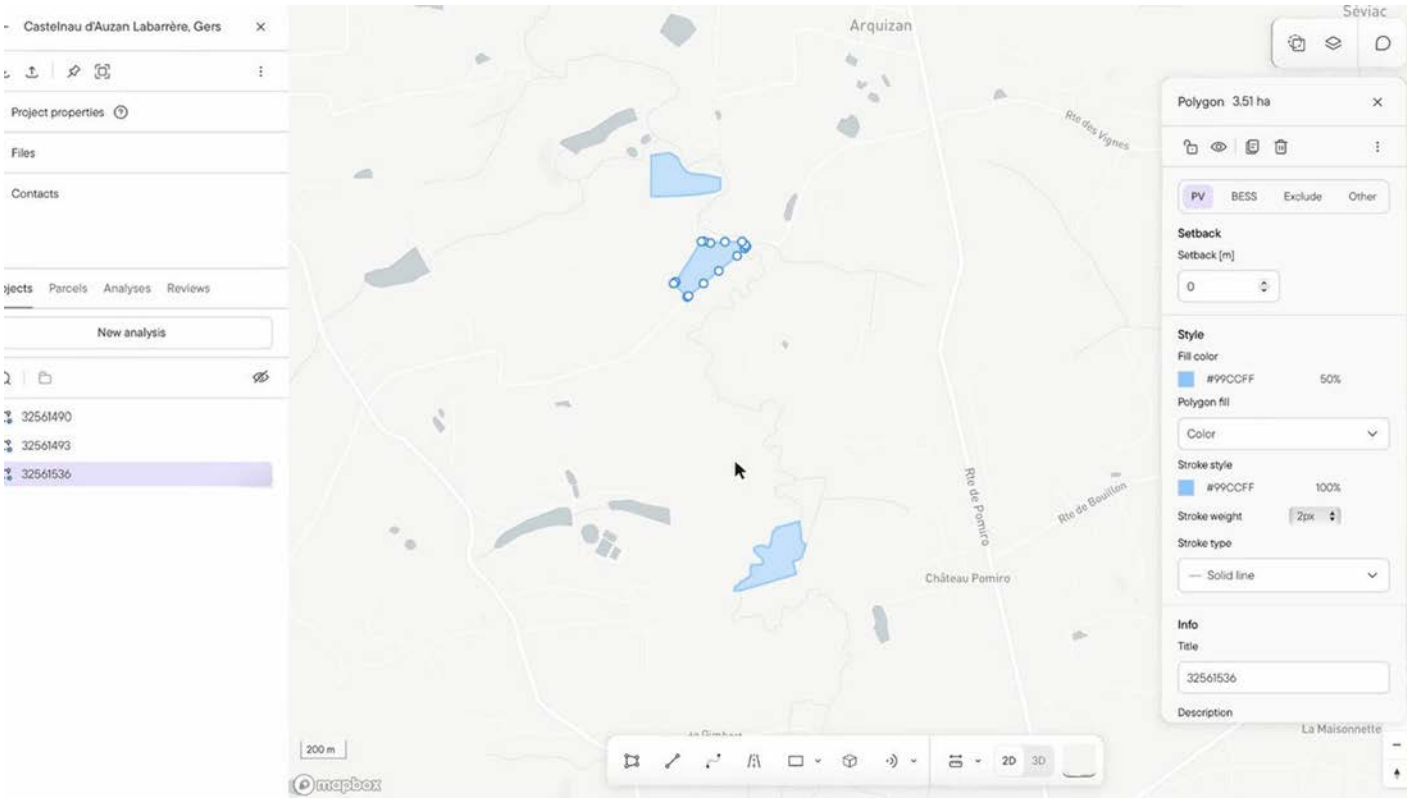
The same principle applies to battery storage. A preliminary layout can test equipment placement relative to neighboring properties and identify where noise mitigation, such as a barrier, may be needed. Comparing alternatives early can inform commercial discussions and community engagement before the developer commits to overly optimistic lease terms.

The screening result should be revisited as the design develops. The advantage is that new findings can feed into another comparison promptly. Detailed engineering and further surveys remain necessary as the project advances.

Terrain data deserves particular attention. Fixed-tilt arrays, conventional single-axis trackers and terrain-following trackers can have different slope and grading requirements. Combining terrain analysis with preliminary layouts lets developers compare configurations earlier. An elevation layer suitable for regional screening may still be insufficient for detailed design. Its age, resolution and processing need checking, with appropriate surveys commissioned as the project advances.

Improving the prospects where you build

Once a site is selected, the question becomes how to improve the prospects of a workable proposal. Residents regularly ask what a project will look like from the road or their home. Previously, developers might offer a photograph of another project or wait for a specialist visualisation. A view based on the proposed layout and local terrain provides a more relevant starting point.



Mapping candidate parcels in Glint Solar's land screening module

Credit: Glint Solar.

"Developers can now compare options themselves, rather than wait for specialists to assess each one, then ask for detailed analysis of the most promising sites"

Developers can compare views from specific locations, test equipment placement and show the effect of proposed screening. Those views need to reflect the assumptions behind the screening. A newly planted hedge and a mature hedge produce different views, and seasonal changes may affect visibility. Showing those differences is more useful than presenting only the most favourable image.

Early acoustic modelling can support similar conversations for battery storage. It allows teams to compare indicative layouts, equipment options and mitigation before commissioning the formal assessment. If moving equipment farther from a home reduces the likely impact, that change is easier to consider while the design is still flexible.

These tools help developers make early decisions and discuss the proposal with residents. The surveys, engineering assessments and formal studies required for permitting are still needed. Nor do they establish that a community will accept a project. Residents may have concerns about land use, local benefits or the development process that no rendering can resolve.

Developers can now test alternatives during early engagement, rather than defer every question until a later study. The value is a more specific conversation, with room to adapt the proposal in response to feedback.

Keeping project information connected

Disconnected information creates avoidable mistakes. Two colleagues may send the same landowner different lease offers or contact an owner who has already declined. The problem can persist even where tools exist: low adoption leaves updates in inboxes or spreadsheets, while siloed systems hide them from the next person. The information gathered during screening and engagement needs to travel with the project, including outreach history and agreed terms.

A shared map can connect parcel status, boundaries, constraints and design revisions with the documents and discussions behind them. If a landowner reserves part of a field, the next layout should reflect it. If local requirements change, the team should see which projects need review. Software also needs to fit the team's actual workflow so recording an update is straightforward. Everyone needs to know what information they are responsible for updating and keep it up to date.

An investment committee needs the reasoning behind the capacity estimate and site assessment. A record of the screening criteria and source information, together with the unresolved issues and next steps, allows it to assess the opportunity. That supports a decision about whether to stop, investigate further or advance the project.

At portfolio level, a geographic view also helps teams examine shared risks. Several projects in different development stages may depend on the same grid infrastructure or sit within the same jurisdiction. Seeing that relationship supports prioritisation alongside the individual project assessments.

Integrating tools and expertise

There is no single software architecture that suits every developer. Large organisations may build their own platforms and integrate purpose-built mapping and design tools through application programming interfaces (APIs). Smaller teams may find everything they need for screening and preliminary design in off-the-shelf solutions. In either case, developers need to explore options themselves and share the results with specialists without losing the project context.

Developers need to decide which tasks are worth doing themselves and which can be handled by existing tools and datasets. Collecting local planning rules, mapping grid infrastructure and copying utility data into spreadsheets takes time away from assessing sites. Using shared data still leaves each developer to choose where to focus, which projects to pursue and how to bring them forward.

Developers can improve how they work by connecting the tools they already use. GIS, design, engineering and performance modelling software need to share information with each other and with project records. Site boundaries, design assumptions and previous revisions should be carried across, so teams work from the same information and know who is responsible for keeping it up to date.

Developers can now compare options themselves, rather than wait for specialists to assess each one, then ask for detailed analysis of the most promising sites. Grid, permitting and survey uncertainties remain, but teams can see their implications earlier and keep the findings connected as the project evolves.

Mapping software supports that shift when it combines usable data, preliminary design and a workflow people actually use. The result is a clearer basis for deciding which sites deserve further investment and how the projects that advance should be designed. ■

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Author

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Plug-in solar in the US: can policy and safety keep pace with demand?

Balcony solar | Balcony solar offers a low-cost route to residential clean energy, particularly for renters and apartment dwellers. Shreeyashi Ojha explores how fragmented legislation, uncertain economics and unresolved safety challenges could affect how quickly plug-in PV systems scale across the US



Credit: Yuma Solar via Unsplash

A plug-in photovoltaic (PIPV) system, or "balcony solar", is built around a simple proposition: enable households to generate their own electricity without the expense and complexity of a conventional rooftop installation.

Typically comprising one or more solar modules connected to a microinverter, these systems plug into a household electrical circuit, allowing generated electricity to supply building loads in real time. Surplus power may be exported to the grid, subject to local regulations and system configuration.

Some systems incorporate battery energy storage systems (BESS) to store excess generation for later use, while more advanced configurations feature dedicated circuits and smart controls, including export-limiting functionality. Higher-power systems can also connect to dedicated 240V circuits, depending on local requirements.

For consumers unable to install rooftop solar, PIPV offers a potential entry point into renewable energy with relatively little installation work. Its appeal is particularly clear for renters and apartment residents, who may lack access to suitable rooftops or the authority to undertake conventional installations.

Plug-in PV offers a potential entry point into renewable energy with relatively little installation work

However, the US market faces a different set of challenges from Europe, where plug-in solar has gained traction. Affordability, electrical safety and a fragmented regulatory landscape are emerging as defining issues for the technology's development.

A market shaped by state policy

US PIPV legislation is advancing, but progress remains uneven across the

country. As of September 2026, 31 bills are currently under consideration in the US, with ten signed into law, one awaiting the governor's approval, one advancing through the legislative process, four in committee and 15 stalled.

While a further five bills failed to pass into law, the sheer number of proposals reflects growing interest in enabling residents to use small, plug-in solar systems. A 1,200W maximum output is common among proposals, although requirements vary by jurisdiction.

New York's SUNNY Act (S8512/A9111) had passed the legislature and is awaiting final enactment, while Massachusetts' H5175/S3143 is advancing. Proposals in Pennsylvania, Ohio, Michigan and Washington DC are in committee discussions, and the differing progress of these measures highlights the fragmented regulatory landscape facing the US PIPV market.

By September 2026, nine states—Colorado, Connecticut, Maryland, New Hampshire, New Jersey, Maine, Utah, Vermont and Virginia—had signed plug-in solar legislation into law. Utah was an early pioneer, introducing a 1,200W limit in 2025 and helping establish a model for subsequent state-level initiatives.

In 2026, further legislation advanced across the country, with system-size limits, interconnection requirements and tenant protections emerging as important areas of policy development. California's SB 868 and New York's SUNNY Act have cleared their respective legislatures and are awaiting final enactment. Implementation dates also varied: Colorado's law is scheduled to take effect on 1 January 2027, while New Jersey's Garden State Balcony Solar Act was due to take effect on 1 March 2027.

For Cora Stryker, co-founder of rooftop solar non-profit Bright Saver, the expansion demonstrates that consumer interest is already present, even as regulation lags.

Bright Saver launched a plug-in solar system costing less than US$300 and received thousands of orders within weeks, according to Stryker. "It sold out within days and we know people want it and the regulatory framework really is lagging behind," she tells *PV Tech Power*.

She argues that rising energy costs have made consumers increasingly interested in generating their own electricity, framing the appeal in terms of both affordability and resilience. "Folks are eager to be empowered to produce their own energy," she says. "It is not just an energy affordability issue; it is an energy security issue."



Credit: Sergio Martins via Unsplash

UL Solutions says safety assessments should consider the complete system, rather than panels in isolation. Credit: Sergio Martins via Unsplash

The challenge is creating a regulatory environment that allows manufacturers to supply products consistently across state borders.

"First of all, we have a very fragmented policy landscape," Stryker says, pointing to the state-level determination and enforcement of interconnection rules. Different requirements can increase development costs, complicate approvals and prevent manufacturers from achieving economies of scale.

In the worst case, she warns, "a manufacturer might have to have a different system in New York than they sell right across the line in New Jersey."

For Stryker, legislation must go beyond permitting the technology. It must also address who can use it. Renters and apartment residents may remain excluded if landlords, homeowners' associations or building requirements can prevent installation.

She identifies New Jersey, Virginia and Colorado as particularly relevant models for combining interconnection reform with tenant protections. "Because without renters' rights, this remains restricted to a population that frankly can already get solar, already get rooftop."

Her proposed framework has three priorities: interconnection rules appropriate to small systems rather than conventional rooftop installations; tenant protections that prevent unnecessary barriers, including disproportionate building rewiring requirements; and adaptable certification provisions that do not lock legislation to a single private provider.

"We cannot put a private company in statute," she says, arguing that legislation should establish safety requirements while allowing standards and technologies to evolve.

Stryker also cautions against treating utilities as uniformly opposed to balcony solar, pointing to Con Edison in New York as an example of a utility that engaged with Bright Saver on safety questions.

Ultimately, the question is whether individual states can establish workable rules without creating a patchwork that increases costs and limits access. "The market is fragmented, and that is a really bad thing for all Americans," she says.

The economics of scaling up

Regulatory permission alone will not guarantee widespread adoption. Joseph Shangraw, research analyst for solar supply chains at Wood Mackenzie, identifies consumer economics as a major obstacle to the US market's development, and compares this to the industry in Germany.

"Germany was the first country to successfully adopt plug-in solar off the ground," Shangraw tells *PV Tech Power*. At its peak, he says, "about 20-25% of all residential solar sold by capacity was plug-in solar".

The technology's attraction is straightforward: consumers can access solar without incurring many of the interconnection, construction and installation costs associated with conventional rooftop systems.

However, electricity prices and housing patterns differ between Europe and the US. "Electricity rates tend to be lower on average in the US than in Europe," Shangraw says, meaning consumers can save less in monetary terms from equivalent equipment and generation.

The housing market presents another challenge. European plug-in solar is well suited to apartment buildings with balconies and porches, whereas the US has a greater prevalence of single-family homes. Renters may also be reluctant to make upfront investments in properties they do not own.

Tariffs further complicate the economics. Shangraw estimates that the prevailing US tariff environment could make upfront costs 20-50% higher than in Europe, potentially resulting in "a 50% longer payback period before you actually feel like you're making money off of this."

"It always is going to come down to cost," he says. "People will buy a product if it's going to save them money."

Lower system prices, wider availability and fully certified kits will therefore be important to the market's development. Shangraw also sees plug-in storage as an opportunity to improve system economics by increasing self-consumption and making solar generation available beyond daylight hours. "Plug-in storage is going to be a big component of this," he says.

Yet even if prices fall and legislation expands, PIPV faces a fundamental question: can equipment designed to connect through a familiar household outlet be used safely within the US electrical system?

Safety: the challenge behind the plug

For UL Solutions, an Illinois-based testing and certification company, that question requires examining the complete system rather than treating panels, inverters and cables as separate components.

Ken Boyce, vice president and principal engineer at UL Solutions, says the organisation identified two broad areas of concern: the inherent safety of PIPV equipment and its interaction with the electrical wiring of the building.

"It really does have to be considered as a system, not just an assembly of these individual components," Boyce tells *PV Tech Power*. "These systems generate electricity, right? They're tiny power plants, if you will."

UL Solutions used hazard-based safety engineering to assess risks of electric shock, fire and injury. Its findings informed UL 3700, published earlier in 2026, which establishes requirements intended to address these hazards.

One concern arises from the plug itself. Conventional household appliances draw electricity from a receptacle, but PIPV systems can feed electricity back into the circuit. When a system is disconnected while its panels are still receiving light, the inverter may continue generating AC power.

"In the absence of other safety protective circuits, there would be hazardous voltage accessible on plug blades," Boyce warns. "So, a person could easily touch those and be subjected to an electric shock hazard."

UL 3700 therefore requires additional protection to stop power export before someone can contact a hazardous voltage at the plug. Existing inverter shutdown requirements designed to protect utility workers are not sufficient to address this particular risk, Boyce says.

A second concern involves residential circuit protection.

Circuit breakers are designed to protect wiring and electrical equipment against excessive current. However, when a PIPV system injects electricity downstream of an upstream circuit breaker, the breaker may not detect the additional current flowing through parts of the circuit.

"They inject current into that electrical circuit that the circuit breaker in the panel board is blind to," Boyce says. "It cannot be perceived because it's being injected into the circuit downstream of the circuit breaker."

An overload may cause gradual deterioration of connections or conductor insulation, potentially creating a fire hazard that develops over time. "You could have a glowing electrical connection that takes weeks or even months to manifest itself as a fire hazard," he says.

Potential mitigations include ensuring that wiring and electrical equipment can safely accommodate the combined current, or deploying power control systems that monitor circuits and intervene when current reaches unsafe levels.

UL Solutions also examined interactions with ground-fault circuit-interrupters (GFCIs), which provide additional protection against electric shock. Boyce says a PIPV connection that back-feeds a GFCI can potentially damage the protective device while allowing it to continue supplying power, creating a failure that may not be apparent to consumers.

The findings underline why safety cannot be established simply by confirming that individual components function correctly. The complete system and its interaction with the building's electrical infrastructure must be assessed.

From certification to a consistent national framework

UL Solutions published a white paper detailing its PIPV safety research in December 2025, subsequently translating its findings into UL 3700 requirements. The standard is intended to establish safety outcomes without restricting manufacturers to a single technical design.

However, Boyce says market testing identified a significant gap between those requirements and the products then available. UL Solutions purchased and tested products from the market, and none of those tested complied with UL 3700.

"That really is important because it does show that there are safety issues with products that are on the market today," he says. He maintains that the technology can be made safe using existing engineering, provided appropriate safeguards are incorporated from the outset.

Certification is only one part of the regulatory challenge. The 2026 National Electrical Code (NEC) does not specifically address PIPV systems, while its status as a model code means it becomes enforceable only when adopted by a state or local jurisdiction, potentially with amendments.

"Until that model code gets adopted by your jurisdiction, it's not enforceable," Boyce says.

Individual states are developing different approaches, some referencing UL 3700 and others pursuing alternative mechanisms. Greater consistency could emerge through the NEC, with the 2029 edition already under development and numerous proposals addressing PIPV.

Boyce says there is also a potential route for earlier changes through a tentative interim amendment to the 2026 NEC, depending on whether consensus can be reached through the code-development process.

For consumers, certification could provide a clearer indication that a product meets defined safety requirements. Boyce identifies a UL mark demonstrating compliance with UL 3700 as the "most important practical indication" that a PIPV system is safe. UL Solutions is working towards its first certification.

The technology offers an opportunity to extend solar access beyond households with suitable rooftops. But its promise depends on more than demand or legislative momentum. Manufacturers need predictable rules, consumers need a convincing financial proposition and regulators need confidence that systems can operate safely within residential electrical installations.

As state-level legislation expands, the task is to bring these requirements together. PIPV's simplicity may make it accessible, but building a scalable US market will require a coordinated framework that makes the technology affordable, practical and safe. ■

M&A due diligence for solar and storage in the AI era

Finance | Speed and accuracy matter for solar and storage diligence. Smart investors are harnessing artificial intelligence to achieve both, write Jacob Sandry and Rubin Sidhu



Credit: Terra-Gen

Before AI, before the Inflation Reduction Act (IRA) and well before the regulatory changes of the past two years, diligence on a solar and storage project was already a serious undertaking. That baseline complexity is easy to forget in a conversation focused on what has changed, but it matters for understanding why the current moment is so consequential.

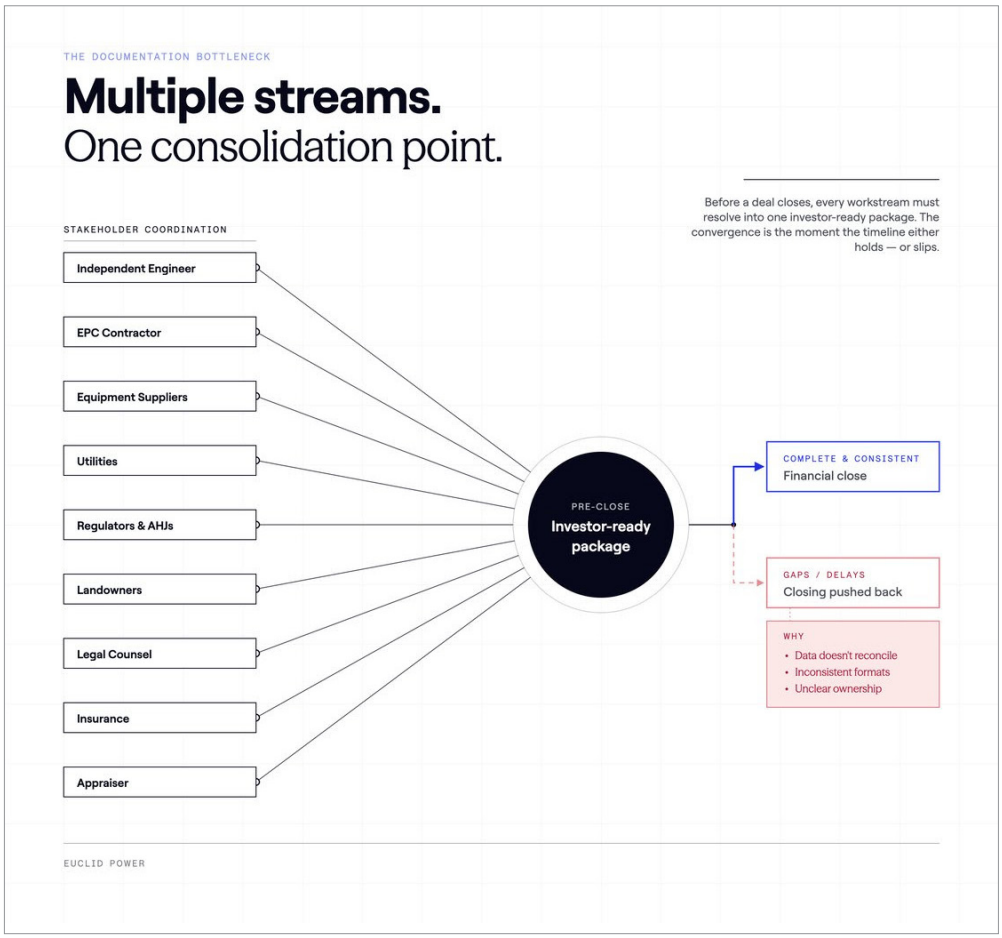
Every project is, at its core, a collection of several hundred contracts and documents. These documents govern site control and land rights, interconnection to the grid, local and state permitting, equipment procurement, offtake arrangements, tax structure and ongoing operations and maintenance obligations. Taken together, they define what a project is, what it is worth and what risks an investor is assuming.

The problem is that this information has never been easy to access or use. It lives across multiple versions of unstructured PDFs, scattered data rooms and inboxes, in inconsistent formats and disconnected from the financial models, risk registers and workflow tools that deal teams actually rely on. Extracting, organising and synthesising that information has historically required significant human time and messy coordination of multiple specialised advisors working in parallel.

Solar and storage due diligence has become increasingly complex in a time-pressured commercial environment

A typical investor coordinates across an independent engineer or technical advisor, tax counsel, real estate counsel, transaction counsel, an environmental consultant and a financial advisor. Each brings a distinct scope, a distinct working style, and a distinct set of information requests. Workstreams overlap. Handoffs are slow. Information sits in inboxes rather than shared systems. The result is a diligence process that routinely takes three months or more to complete—in a market where deal windows are often measured in weeks.

That mismatch between the pace of deals and the pace of diligence was already a problem before the current



Credit: Euclid

wave of regulatory and market change. It has since become significantly more acute.

And then everything got more complicated

The passage of the IRA, the One Big Beautiful Bill Act (OBBBA) and the subsequent guidance introduced new layers of compliance obligations that have materially expanded the scope of what diligence must cover. These are not marginal additions. For many transactions, they have become the most consequential and time-consuming workstreams in the entire process.

Prevailing wage and apprenticeship requirements now attach to Investment Tax Credit (ITC) and Production Tax Credit (PTC) eligibility in ways that require detailed documentation of labour practices during construction. Prohibited Foreign Entity (PFE) restrictions require more granular diligence on the ownership, control and material assistance for equipment and components used by qualified facilities and energy storage technologies claiming the technology-neutral credits. Domestic content eligibility for the ITC adder requires careful tracking of where steel, iron and other products and components are manufactured—a task that can involve coordinating across multiple suppliers. Beginning-of-construction rules create schedule-sensitive compliance obligations tied to long-lead equipment procurement and physical work commencement, with significant tax credit value at stake if timelines slip.

Figure 1. A typical diligence process can routinely take months in a market where deal windows are often measured in weeks

Tariff exposure has added another layer of diligence for imported PV and BESS equipment. Investors need to understand not just the potential cost of tariffs, but who bears that risk under equipment supply and EPC contracts and whether project contingencies can absorb unexpected increases.

What used to be a checkbox has become a full workstream, in many cases, multiple workstreams

The investor universe has also shifted. Tax credit transfer investors, infrastructure funds and hyperscaler-adjacent investors have entered the market in significant numbers, some without deep solar and storage diligence experience. The assumptions and frameworks these investors bring do not always map cleanly onto the risk profile of the assets they are evaluating.

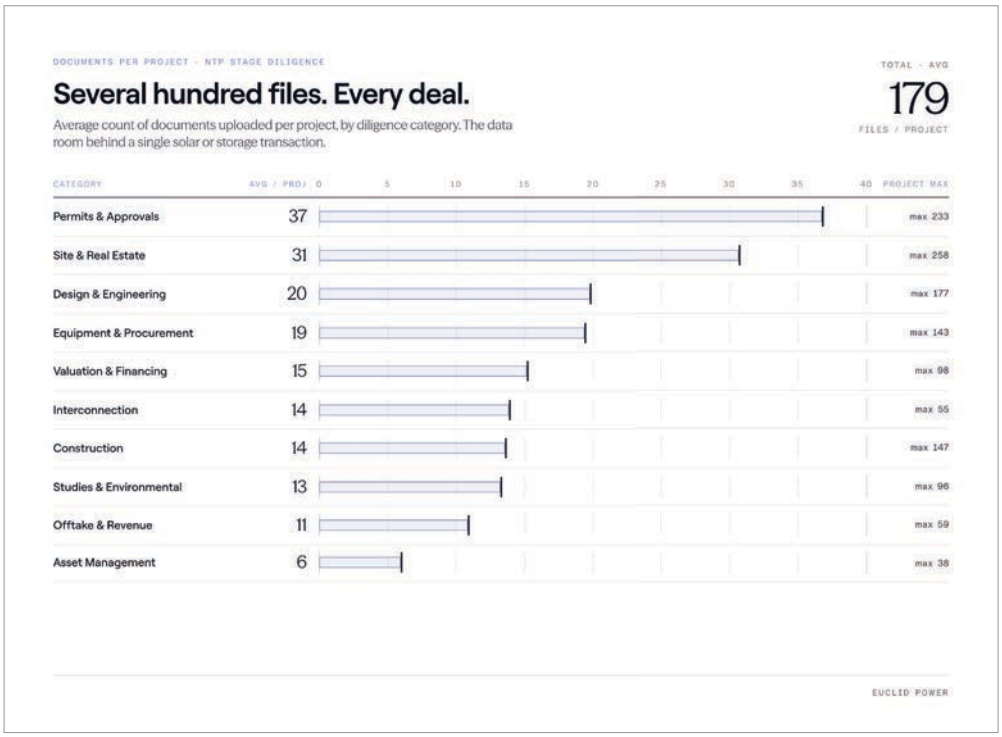
The consequence is a diligence environment in which the risks most likely to re-price or kill a deal are also the ones most likely to be missed. Solar yield assessments are systematically optimistic in ways that experienced technical reviewers have documented for years. Storage revenue underwriting requires offsetting merchant exposure with some contracted revenue in markets where merchant assumptions are difficult to validate. Domestic content compliance for the ITC adder eligibility remains incompletely documented in a large share of data rooms. Long-lead equipment procurement creates schedule dependencies that are rarely reflected accurately in seller-provided timelines. Interconnection costs and timing continue to surprise investors who underestimate network upgrade exposure.

To make this concrete: on a recent project we worked on for a client, the project developer was targeting a late 2030 commercial operation date. The project's underwriting depended on revenue from a competitive state clean-energy solicitation that requires commercial operation by 1 January 2030, to be eligible. Nothing in the data room explicitly flagged the mismatch; the schedule and the offtake assumption were internally coherent. They were just inconsistent with each other. Without the right diligence framework, the project the buyer thought they were acquiring—one eligible for the offtake programme that anchored the financial model—did not exist. Catching that before exclusivity was a multi-million-dollar valuation event.

The real deal-killer in this environment is not risk itself; it is discovering risk late, deep into exclusivity, when a late-breaking finding does not just complicate the transaction but resets valuation, burns negotiating leverage and can kill the deal entirely.

A market moving faster than the existing process

Against this backdrop of structural complexity, the pace of market activity has accelerated sharply. AI and electrification are driving a surge in power demand unlike anything the industry has seen in a generation, particularly for firm, reliable power. As the industry races to advance six years' worth of development pipeline within the four-year window ahead of the Investment Tax Credit cliff, development, financing and merger and



Credit: Euclid

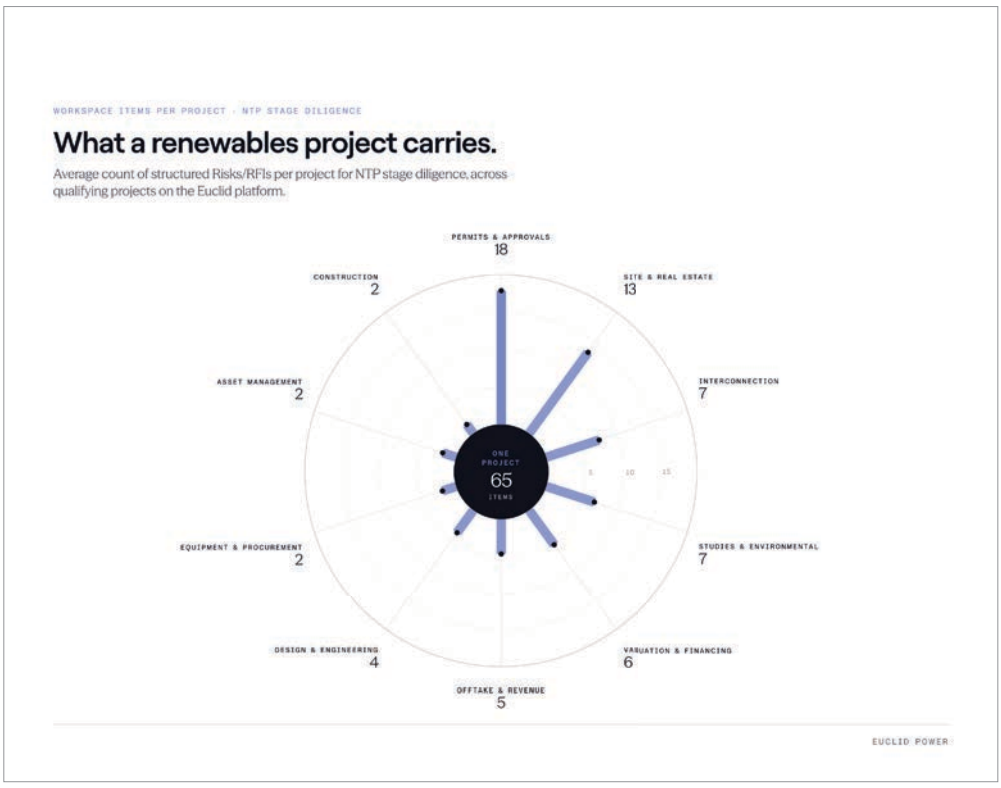
Figure 2. Due diligence processes generate hundreds of individual documents

acquisition (M&A) volumes are elevated and likely to remain so.

Hundreds of projects are actively changing hands at any given time, with thousands more in various stages of development and marketing. Each one is its own snowflake: a unique configuration of contracts, permits, interconnection agreements, equipment procurement timelines and compliance obligations, all of which must undergo due diligence for every financing and M&A transaction.

The opportunity for investors in this environment is real. So is the challenge. Quality and risk vary enormously across the available universe of assets, and the ability to identify the best opportunities quickly is increasingly a source of competitive differentiation. The core tension is straightforward: the market is moving faster than traditional diligence processes were built to handle.

This is precisely where AI can change the equation.



Credit: Euclid

Figure 3. AI can transform unstructured contract data into structured, actionable information at scale and speed

The unlock: AI turns unstructured data into infrastructure

The core challenge of project diligence has always been the same: critical information is trapped in unstructured documents, and extracting it and connecting the dots accurately is slow, expensive and dependent on the availability of experienced reviewers. Across the most recent 225 transaction projects we have supported, a typical seller's data room contains roughly 165 documents and generates roughly 71 distinct diligence findings—risks identified, RFIs to the seller, actions to be taken—before close. The most complex projects we see easily double those numbers. AI addresses this problem directly, and the implications for how diligence is done are significant.

In this context, the real superpower of large language models is that they can transform unstructured contract data into structured, actionable information at a scale and speed that was previously impossible. A data room that might take a team of analysts several weeks to process can now be ingested, organised and cross-referenced in a matter of hours. The result is an entirely new kind of output: a shared data infrastructure that supports faster decision-making, more accurate communication across the deal team and more effective stakeholder management throughout the transaction.

The practical implications for transaction timelines are substantial. A red flag report used to take a couple of weeks to produce. Euclid Power recently launched a 24-hour Red Flag Snapshot product. A full diligence package that once took several months can now be delivered in under a week. These improvements represent a fundamental change in what is possible within a given deal window—and in how many deals an investor can realistically pursue and close.

Though AI makes the initial pass much faster, its real value is in the quality of the foundation it creates for the human judgment that follows.

That distinction is important. AI is probabilistic. The best models in deployment today are estimated to be 70-80% accurate on domain-specific tasks, and they present their outputs with a confidence that does not reflect that uncertainty. In a diligence context, the gap between 80% and 100% accuracy can represent a multi-million-dollar miss. Well-designed AI systems, built with domain-specific knowledge and designed for the

specific risk taxonomy of solar and storage transactions, can bring that accuracy to, say, 95%. The residual 5% gap is precisely where expert validation becomes not just valuable but essential.

The model that works: AI and expertise in tight loops

The diligence model that is producing the best outcomes is not AI replacing expert review, but AI and expert review operating in tight loops, each doing what it does best.

AI workflows are most valuable when they are built around where risks actually live, organised by project type, development stage, geography and deal structure. A well-designed system applies a risk-aware framework that reflects the specific compliance environment, asset class and stage of development of the projects being evaluated. That specificity is what separates a useful AI-assisted process from a fast but unreliable one.

Instead of spending the majority of their time extracting and organising information from documents, expert reviewers are now focused on connecting the dots: making judgments that only experience can support, evaluating whether a yield assessment methodology is credible, assessing the enforceability of a key contract provision, determining whether a schedule assumption is realistic given the specific interconnection queue dynamics in a given market, or interpreting the significance of a risk that an AI system has correctly flagged but cannot place in context.

Consider a solar project in New York State at an advanced stage of development with no secured offtake. Utility-scale solar in the state is almost entirely dependent on a NYSERDA Tier 1 REC agreement as the only viable offtake path, making the absence of one a critical risk, not merely a risk. Reaching that conclusion requires knowing how NYSERDA solicitation cycles work, what curtailment levels do to strike price competitiveness and what the interconnection security deposits, lease payments and long-lead procurement commitments required before the next award date mean for the investment thesis. That is not a document extraction problem. It is a market judgment.

Or, consider a notice-to-proceed-stage (NTP) BESS project without secured offtake. An AI system will correctly flag this as a critical risk, and it is. But the severity of that gap is not uniform across markets. In Nevada, where a single investor-owned utility dominates the offtake landscape, a missing PPA at NTP is a critical risk: without it, the project may not have a viable path to revenue. In CAISO, the same gap is materially different. The market supports a range of offtake structures—RA contracts, utility tolling agreements, community choice aggregator agreements, merchant participation—that give a well-positioned project genuine optionality. Treating both situations identically in underwriting is a mistake that only market experience can prevent.

The initial project diligence review that previously required three people working for a week now routinely takes one person less than a day. That acceleration is more than a marginal efficiency gain; it is a structural change in the economics of diligence and in the number of opportunities an investor can evaluate with a given team.

This model is in practice today among the investors and advisors who have invested in building the right systems and pairing them with the right expertise. The early adopters are making better-informed decisions on more opportunities, with less duplicated effort across their advisor ecosystem.

The competitive advantage payoff

The strategic implications of this shift are straightforward, but worth stating explicitly. In a buyer's market with hundreds to thousands of available projects, the ability to screen more opportunities—faster, more consistently and at lower cost per transaction—is a structural competitive advantage.

Most institutional investors and lenders active in the solar and storage market today are not constrained primarily by capital or by access to deal flow. They are constrained by their capacity to undertake the necessary diligence and close transactions. The bottleneck is operational, not financial. An investor who can evaluate two deals per month is categorically different from one who can evaluate ten. The latter will see more of the market, identify the best value opportunities more reliably, pass on weaker deals faster and deploy capital more efficiently with the same underlying resources.

AI-driven diligence will become table stakes in this market within a relatively short period. The question for investors and their advisors is not whether to adopt it, but how to build the domain expertise and IP required to use it effectively. The differentiators are risk knowledge, transaction experience and judgment that determine whether the technology produces accurate, actionable output or fast, confident mistakes.

Conclusion

The complexity of solar and storage M&A diligence has never been higher. New compliance regimes, an evolving investor universe and the compressed timelines created by the federal tax-credit changes have all raised the stakes for getting diligence right. At the same time, the tools available to do it well have never been more powerful.

The investors and advisors finding the best deals in today's market are the ones who have figured out how to leverage AI alongside human expertise, in the right combination, with the right workflows and with a clear-eyed understanding of where human judgment remains irreplaceable.

The bar has moved. Investors will modernise on their own terms, or they will be forced to when they lose deals they should have won. Diligence, done right, is no longer just about avoiding bad transactions. It is about finding good ones, faster and at scale. ■

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Hail-hardened modules—promise, limitations and the procurement gap

System economics | Tracker stow technology and tougher module hardware have emerged as the solar industry's main solutions to the growing challenge of hail damage. Michael Perron of insurer FM examines the economic decisions behind choosing what combination of module durability and tracker capability offers the greatest resilience per invested dollar



Credit: Nextpower

Over the past decade, utility-scale solar has become dramatically more cost competitive. Manufacturers improved efficiency and reduced cost per watt through larger module formats, thinner glass constructions and lower material use. As module sizes increased, thinner glass helped keep module weights within practical limits for transportation, installation and tracker compatibility. The approach improved project economics and accelerated deployment, but it also reduced durability in some modern module architectures.

In parallel, utility-scale deployment expanded into regions with significant hail exposure, increasing the importance of understanding how those design changes affect long-term resilience.

Mechanical-durability testing presented by Colin Sillerud at the 2024 PV Reliability Workshop showed that some modern module designs fail load testing at lower thresholds and that mounting configurations can materially affect when failure occurs. The implications are twofold: component durability matters, and performance must be evaluated as part of the complete module and mounting system.

An optimal combination of module durability and tracker capability offers the greatest protection against hail damage

Following the 2019 hail loss at the utility-scale Midway Solar project in West Texas, defensive hail stow gained greater industry attention and became a central resilience strategy. Hail stow can be highly effective when successfully executed, but it depends on forecasting, communications, controls, power availability and operational execution. More resilient modules provide an alternative and complementary layer by directly reducing module fragility.

Multiple manufacturers now market hail-resilient products, and developers are purchasing them. The unresolved questions are how much additional resilience those products actually provide, what premium they command, whether developers are willing to pay it and how their lifecycle value compares with investment in progressively higher stow angles. The central question is no longer whether hail-resilient modules can be built. It is whether the industry is properly valuing resilience and whether investing in more durable modules creates greater lifecycle value than continuing to rely primarily on increasingly aggressive stow strategies. Better testing, greater data transparency and earlier project decisions are needed to answer those questions consistently.

Commercial scale extends beyond one manufacturer

The strongest publicly disclosed evidence of commercial-scale manufacturing currently comes from LONGi. According to the company, more than 1.8GW of its Hi-MO 5 Ice-Shield modules have been shipped in the United States since the product's mid-2024 launch. The US configuration uses 3.2mm fully tempered front glass and 2.0mm heat-strengthened rear glass in a reinforced package designed for hail and wind resistance. Canadian Solar has also reported utility-scale deployment, while Trinasolar, Jinko, JA and others offer hail-focused configurations. Selected examples are summarised in Figure 1.

Independent third-party evaluation is also entering the market. Canadian Solar's US-manufactured TOPCon and HJT Low Carbon HP modules received FM Approvals recognition under FM 4478 and FM 4480 identified-component standards, making them the first FM Approvals PV modules listed as identified components for severe hail zones. The listed products use 2.5mm tempered front and rear glass and have earned this recognition by passing severe hail resistance, design qualification and safety testing. Third-party evaluation is important because it helps validate manufacturer claims.

The products are not directly rankable. Public manufacturer claims use different hail diameters, velocities, impact angles, sample sizes and pass criteria and performance depends on the exact bill of material, factory and mounting configuration.

Figure 1. Illustrative examples of hail-resilient module approaches. Products are not directly comparable because manufacturers use different hail sizes, impact velocities, test methods, impact angles, sample sizes and pass criteria



Accordingly, performance comparisons should be based on the exact bill of materials, manufacturing location, mounting configuration and consistent test conditions rather than product labels alone.

What hail-hardened means

Hail-hardened is not a single architecture. Approaches include fully tempered 3.2mm front glass, 2.5mm/2.5mm tempered glass-glass packages, thicker front-glass/backsheet configurations, reinforced laminates and other design strategies. Performance depends on the quality of the complete bill of materials, factory, frame, laminate, mounting and dimensions, not a brand name or thickness label. Some developers and manufacturers are exploring chemically strengthened thin glass and other materials-engineering approaches. Modules using 4mm front glass for tracker applications have also been developed, including Mission Solar's MSE330SB1A design, illustrating another pathway toward greater durability. The extent of its current commercial availability was not confirmed for this article.

Manufacturer testing also shows why front-glass thickness cannot be considered in isolation. Hail impact can damage cells beneath intact front glass, while field and laboratory observations have documented rear-glass fracture even when the front glass survives. Impact location and local stress concentrations can also affect the outcome. Canadian



Figure 2. The allocation of capital in different hail-resilience options requires careful evaluation

Solar's commercial hail-resilient configuration uses symmetrical 2.5mm/2.5mm tempered dual glass, reinforcing the need to evaluate the complete laminate rather than only the front surface.

Testing is informing procurement and risk decisions

Testing and engineering organisations including FM, RETC, VDE, Kiwa PVEL, UL Solutions, GroundWork Renewables/CFV Labs and others are producing evidence needed to differentiate module fragility and mitigation strategies. FM has also conducted its own testing of hail-hardened modules, while FM Approvals provides independent product testing and certification under its applicable standards.

Unlike IEC 61215 qualification testing, which establishes a minimum threshold for module certification, the Hail Resiliency Curve, or HRC, methodology utilises a test-to-failure approach that characterises performance across a range of impact energies. The VDE Americas and RETC methodology uses randomised, regional impacts to develop Weibull probability-of-breakage curves for module centres, edges and corners. FM applies a similar beyond-qualification philosophy when testing panels in a manner conceptually similar to the VDE HRC approach, evaluating behaviour across a range of impact conditions rather than relying solely on certification thresholds.

The resulting data can differentiate exact bills of materials, support site-specific expected-loss modelling and evaluate combinations of module durability and tracker strategy. A key limitation of traditional pass/fail qualification testing is that it does not distinguish between products that narrowly satisfy minimum requirements and products that remain resilient across a much broader range of impact energies. Test-to-failure methods reveal those differences and provide a stronger basis for procurement, engineering, insurance and financing decisions.

Catastrophic glass fracture is one concern, but intact glass does not necessarily mean an undamaged module. Hail impact can crack cells, leading to potential power loss and hot-spot risk. A complete resilient-module specification should therefore evaluate both catastrophic fragility and post-impact electrical performance and safety.

Higher stow angles provide greater hail protection, but are they the best resilience investment?

Hail stow moves tracker-mounted modules to a steeper angle before or during a severe weather event. All else equal, increasing the stowed angle improves hail protection by creating more glancing impacts and reducing the projected area exposed to falling hail. A 60° position therefore provides greater protection than 52°, and 75° provides greater protection than either. The physical benefit is not in dispute.

GroundWork testing indicates that actual hail energy transfer at oblique angles can diverge materially from conventional cosine-squared scaling, with the difference increasing at steeper angles. In testing discussed by GroundWork, measured impact energy at 75° was approximately 30% to 40% higher than the conventional model predicted. FM follow-up testing at 0°, 45° and 60° similarly found that a GroundWork-derived tilt-dependent model better represented the observed 60° glass-breakage threshold than conventional scaling. The finding does not diminish high-angle stow. It indicates that its incremental benefit should be measured rather than inferred from simplified scaling alone.

The capital-allocation question is whether the additional resilience obtained by moving from reliable moderate-angle stow to very-high-angle

stow exceeds what could be achieved by investing the same capital in lower module fragility. Which invested dollar produces the greatest incremental risk reduction for a specific site and configuration remains an open question. The two measures are complementary, not substitutes.

An October 2026 VDE/RETC/LONGi webinar added quantitative evidence. In a VDE model for a canonical 100MW project near Fort Stockton, Texas, the Ice-Shield module produced modelled loss reductions of approximately 80% or more relative to an industry-standard 2.0mm front-glass/2.0mm rear-glass bifacial module. VDE also found resilient modules and steeper stow to be synergistic: either reduced modelled loss, while using both produced the strongest result.

The Texas Solar Nova field example provides a complementary real-world result. More than one million modules automatically moved to 60° during a June 2025 West Texas outbreak; fewer than 200 modules were damaged, and no solar-array insurance claim was filed. The report does not disclose the hail-size distribution striking the array, the wind direction relative to the stowed modules or the achieved row-level orientations.

This event should not be interpreted as direct validation of the separate VDE model. Separately, VDE's conservative 500-year probable maximum loss scenario estimated more than 20% modelled module loss across a broad region for standard 2.0mm/2.0mm bifacial modules stowed at 60° with hail driven into the module face. The results are not contradictory. They show why resilient design should be evaluated across a distribution of events rather than a single successful case.

Hazard uncertainty and layered protection

Hail hazard is not defined by maximum diameter alone. Hailstone density and material strength, impact count, wind velocity, storm duration, hail-size distribution, swath variability and other factors can all influence losses. Large utility-scale sites may experience materially different conditions across the site during the same event.

More resilient modules reduce vulnerability across this uncertainty, while tracker stow reduces exposure when forecasting, communications, power, controls and movement perform successfully. The strongest resilience strategies use both layers together.

Procurement, replacement and project economics

FM has encountered projects where engineering review identified a more resilient module as better aligned with the site's hail exposure, but the modules had already been procured, and a change was no longer practical. Protection then had to be strengthened within the existing design through more aggressive stow and verification that the trackers would respond as intended. These measures remain important for existing thin-glass installations and for new projects, including those using hail-resilient modules. However, they also increase dependence on forecasting, communications, controls, backup power and operating execution. The goal is not to replace resilient modules with increasingly aggressive stow strategies. Rather, once procurement decisions are fixed, active mitigation may become the only practical remaining option. For the large installed base of existing utility-scale projects, tracker performance, operational readiness and hail-stow execution will remain primary resilience tools for many years to come.

FM's 2026 'Power & Renewables Report' found that 78% of power companies say site-selection decisions frequently create downstream exposures that were not anticipated when those decisions were made. Module and tracker choices can create a similar lock-in effect once equipment is procured and foundations and controls are designed.

Tracker capability should be demonstrated as an integrated sequence rather than inferred from a nominal maximum angle. Commissioning and periodic testing should confirm that the system can detect the threat, receive the command, move the field, verify achieved position and maintain protection using backup power when normal power is unavailable. The transition from construction to operation is equally important: trigger thresholds, stow logic, backup-power capability, training, maintenance responsibility and verification records must transfer together if the designed protection is to remain available in service.

Procurement decisions are influenced by more than technical performance and upfront cost. Domestic content incentives, trade restrictions, tariffs, local manufacturing requirements and supply chain considerations may also affect module selection. These factors can influence the availability, pricing and procurement accessibility of hail-resilient products, but they do not change the underlying need to evaluate lifecycle durability and resilience performance.

A catalogue listing for a module is not the same as procurement accessibility. Enhanced hail configurations may require minimum quantities or special production runs, and compatible replacements may be difficult to obtain years later as cells, dimensions, frames and connectors change. Economic effects from module selection can arise throughout the project life, so the analysis should extend beyond the original module invoice to reliability, tracker compatibility, transportation and installation, revenue continuity, maintenance, replacement availability and recovery after loss.

The economics may extend beyond hail alone. Both LONGi and Canadian Solar highlighted that hail-resilient module designs can improve mechanical durability more broadly, including resistance to wind and snow loading. LONGi specifically noted that its Ice-Shield architecture was developed to improve both hail and wind resilience, including wind-load capability up to 3,600Pa when paired with a mainstream tracker, while Canadian Solar highlighted the potential for stronger modules to support mechanical-load improvements and, in some circumstances, racking-system optimisation. Any such offsets must be validated for the specific module, tracker and site conditions, but they should not be excluded from a whole-project cost comparison.

While product announcements, testing results and deployment examples are increasingly available, publicly available cost information remains limited for both hail-resilient modules and tracker systems capable of very-high-angle stow. A DuraMAT discussion estimated that hail-resistant modules may cost approximately US$0.01-0.02/W more, or roughly 1% to 2% of installed project cost. At 250MW, that range equals US$2.5 million to

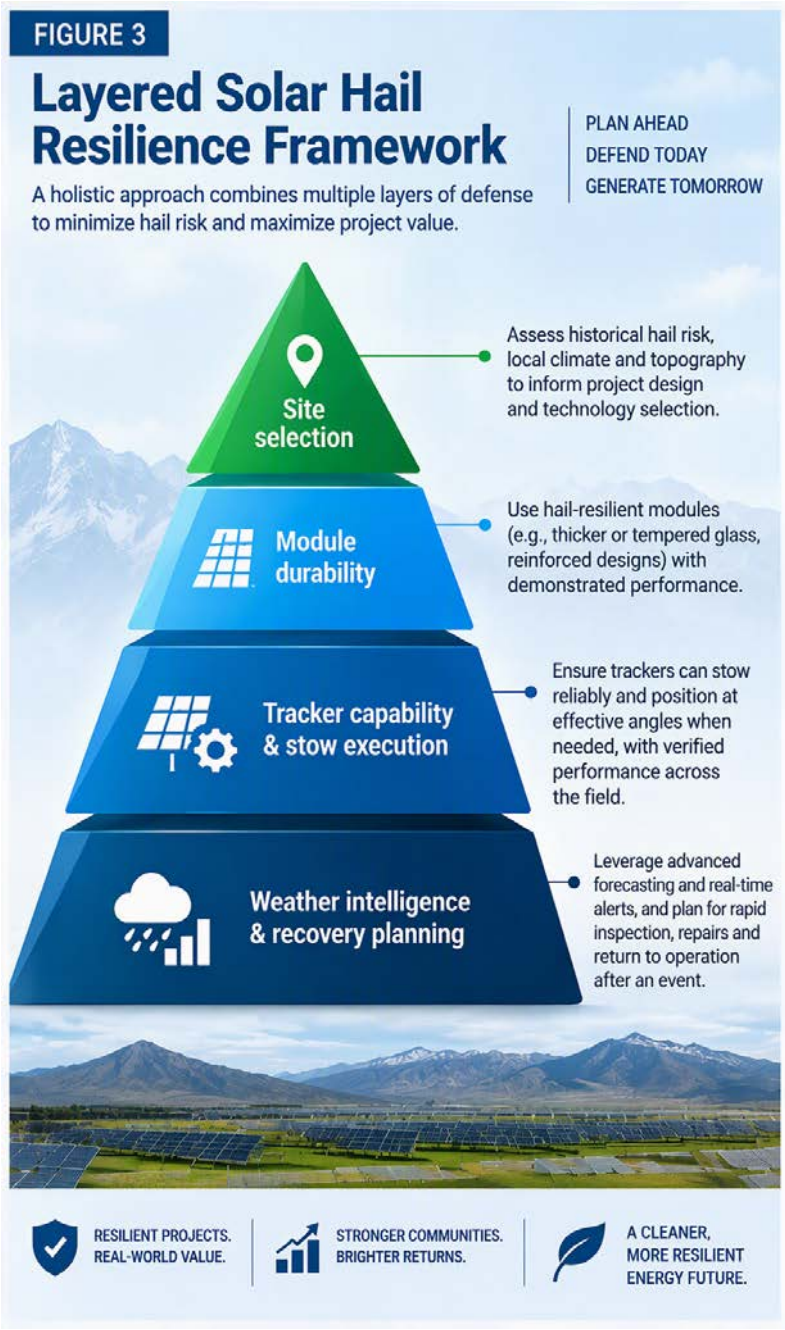


Figure 3. Layered solar hail-resilience framework

US$5 million before offsets. An illustrative FM forum comparison for the same project used approximately US$3 million for more resilient modules and approximately US$5 million for 75° to 78° tracker capability. These figures are directional rather than market benchmarks, but in that example, the resilient module approach had the lower incremental cost.

LONGi also presented a SAM-based scenario for a 100MW project in Itasca, Texas, in which each 0.25-percentage-point reduction in insurance premium increased project NPV by approximately US$4 million. The example was intended as a sensitivity analysis rather than a projection of actual insurance market outcomes or evidence of a guaranteed insurance credit. It nevertheless illustrates the potential financial scale if empirical fragility data support differentiated underwriting and financing decisions. These potential insurance and financing benefits would be in addition to the economic value of avoided physical damage, downtime and replacement costs.

A call for transparent information

Many developers, owners, suppliers and insurers likely already perform portions of this tradeoff analysis internally. The industry's challenge may be less about generating information than making enough of it available to support broader procurement, financing, engineering and insurance decisions. Figure 3 summarises the layered approach required to convert product durability and active mitigation into project resilience.

Conclusion

Multiple manufacturers now offer hail-resilient modules using different approaches to reduce inherent vulnerability. Reliable stow remains an important layer of protection, particularly for the large installed fleet of existing projects. As more fragility, cost and field-loss data becomes available, the industry will be better positioned to identify the most effective combination of module durability and operational mitigation for each site.

The remaining market question is economic: for a given site, what combination of module durability and tracker capability creates the greatest lifecycle resilience per invested dollar? The objective is not to choose between stronger modules and stronger stow strategies, but to determine the combination that delivers the greatest lifecycle resilience for each site. Answering that question requires comparable fragility data, transparent installed-cost information, verified stow performance and field-loss evidence.

The first generation of solar hail resilience taught projects how to move modules out of harm's way. The next should combine reliable movement with modules that are inherently harder to damage. The objective is a resilient configuration capable of surviving expected site conditions throughout the project's operating life. A module that costs less at installation is not necessarily the least expensive module over a 30-year project life. ■

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91

92-97 **Energy storage and smart grids take centre stage in India's renewables shift**
India's electricity system is undergoing a fundamental transformation as the penetration of distributed renewable energy resources grows. Sarita Vijayvargiya and Shantanu Roy examine the role of battery storage and smart grids in the country's new energy landscape

100-102 **Data centre growth, energy storage opportunities and the ratepayer cost debate**
April Bonner looks back at a year in which the data centre debate took centre stage for society and the energy storage industry alike

104-109 **Who's gaining geopolitical advantage in the energy transition?**
Energy transition expert Chris Nelder offers his take on the central premise dividing the globe along 'petrostate' and 'electrostate' lines, analysing news stories from *PV Tech*, *Energy-Storage.news* and *EV Infrastructure News* in 2026

Introduction



Welcome to another edition of Storage & Smart Power, brought to you by the team at *Energy-Storage.news*.

It's the final one of 2026, and whether you're reading this at RE+ or elsewhere, we'd like to give our biggest thanks and warmest gratitude to all our contributors, sponsors, partners and most of all, you, our readers, for supporting us and giving our articles and events your precious time throughout the year.

The industry shift that we've seen in the past couple of years, from the deployment of energy storage in response to policy-driven or merchant market opportunities, to deployment as an infrastructure asset for the long term, now frames how we look at the sector.

At the same time geopolitical winds that have shaped the fates of industries from one corner of the world to the next have also influenced the energy transition in both expected and unexpected ways.

Then we have an AI data centre construction frenzy that is either a bubble, a 'new normal', or a significant wave of activity that nonetheless may or may not peak in the next couple of years.

Behind those major trends lies the fundamental rift between an electrified economy and a fossil-fuel-based one, writes Chris Nelder in his exclusive analysis of the energy transition through a geopolitical lens.

Many of you will know Chris Nelder from his sterling work with the Energy Transition Show podcast and will be familiar with his pioneering thinking and big-picture analysis. Indeed, clean energy luminary Jigar Shah recently described him as "the energy transition's most rigorous and restless chronicler".

We're beyond thrilled to have Chris contribute his thoughts, pulling in content from across our sites *PV Tech, Energy-Storage.news* and *EV Infrastructure News* from throughout the year to elegantly support his thesis that, in the 21st Century, electrostates will have the upper hand over petrostates in industrial competitiveness and energy security. That race is already well underway, he writes.

Infrastructure is the foundation of society, and it makes no sense to consider the electrical grid infrastructure if equipment connected to it is not. In a sense, Chris's article encapsulates that entire trend as it stands on the world stage: so logical in its trajectory, yet so often unrecognised by the very people who should be shaping it, often to their own detriment.

One of the big movers in the electrostate versus petrostate 'war' is India. In this issue, an in-depth article from experts Dr Sarita Vijayvargiya and Shantanu Roy from the Center for Study of Science, Technology and Policy (CSTEP) think tank examines the crucial role of energy storage and smart grids from a technical and economic perspective.

Finally, having mentioned the inescapable shadow of the hyperscalers, *Energy-Storage.news* staff writer April Bonner's article both looks back at a year of elevated activity and conversation—some might even say hype—around data centre development in the US, the role of energy storage within that and how we might expect to see the debate play out going forward.

Andy Colthorpe
Editor
Energy-Storage.news



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Africa's first 24/7 'solar baseload' plant goes online at DRC copper mine

A solar-plus-storage project, claimed as the first of its kind in Africa to deliver 24/7 renewable electricity, has come online at a copper mine in the Democratic Republic of the Congo (DRC). CrossBoundary Energy's 233MWp solar PV and 123MVA/526MWh BESS hybrid resource facility for Kamoa Copper enables the supply of dispatchable baseload power to Africa's largest copper mining complex. As well as reducing the site's carbon emissions, the adoption of round-the-clock (RTC) renewable energy will reduce the mine operator's exposure to diesel fuel cost volatility and supply chain risk.



Credit: Crossboundary Energy

The hybrid system guarantees the supply of at least 30MW baseload power to Africa's largest mining complex

Fluence and Eve Energy agree 206GWh battery supply deal

System integrator Fluence and lithium-ion battery OEM Eve Energy struck a massive 206GWh battery supply framework agreement for 2027-31, one of the largest deals of its kind ever announced. The firms have committed to 16GWh of capacity in 2027, with 190GWh reserved for 2028-2031. The September announcement came a few days after Fluence revised down its fiscal year 2026 (FY2026) guidance, reducing forecast revenues by US$600 million. Eve Energy mainly manufactures in China, with its only non-China facilities to date serving the EV market.

India approves US$19.3 billion Green Energy Corridor Phase III with 50GWh BESS

India's Union Cabinet approved INR 1.86 trillion (US$ 19.3 billion) for the third phase of the Green Energy Corridor, to support renewable energy integration through FY2032-33. The Green Energy Corridor Phase III (GEC-III) scheme aims to reduce renewable energy curtailment and improve grid flexibility. INR 500 billion is to be allocated specifically for 50GWh of BESS. A further INR 1.37 trillion will fund intra-state transmission infrastructure designed to enable the evacuation of up to 135GW of renewable energy.

Nvidia selects BESS solutions for AI facilities qualification programme

Graphics processing unit (GPU) manufacturer Nvidia's new qualification programme for products and solutions that meet its reference design requirements includes three battery storage solutions. Nvidia DSX Ready is a programme for artificial intelligence (AI) factory builders. Organisations can identify products and solutions that have completed category-specific qualification requirements for building AI factory infrastructure. BESS is one of two initial categories, along with cooling distribution units (CDUs). BESS solutions from Hitachi Energy, LG Energy Solution (LG ES) and Tesla are the first on the list.

US grid-scale BESS capacity almost doubled in first 18 months of Trump's second term

The US broke BESS deployment records in Q2 2026 in gigawatt-hour terms, underpinned by growth in the utility-scale segment. The Q3 2026 edition of the US Energy Storage Market Outlook (ESMO) report, published by SEIA and Benchmark Mineral Intelligence, found that 6.7GW/20.2GWh of new battery storage came online in the second quarter, including 17.9GWh of utility-scale. In the first half of 2026, nearly 10.3GW/31GWh entered operation at all scales, up 23% in GWh from H1 2025, including 8.1GW/26GWh of utility-scale batteries.

Hithium unveils 20,000-cycle sodium-ion cell and 4MWh BESS

Hithium hosted a September launch for its new sodium-ion (Na-ion) battery cell and energy storage system product line, promising a 30-year expected operational lifetime. The ∞Cell N785Ah is designed for a 20,000-cycle service life and supports storage durations between 2-hour and 8-hour. It is fully compatible with Hithium's 1,000Ah lithium-ion manufacturing platform and could therefore enter scaled mass production quickly, the company claims. The ∞Power N4.0MWh BESS features an original sodium-ion architecture comprising a stacked cell design and a dedicated battery management system (BMS).

FCC inverter ban poses greater threat than FEOC

Recent moves from the US federal government could prove more damaging to US renewable energy deployment than foreign entity of concern (FEOC) compliance requirements. During September's Battery Asset Management Summit USA 2026 in California, a panel of legal and industry experts highlighted the Federal Communications Commission's (FCC's) ban on foreign-produced inverters and the presidential executive order banning specific power system equipment, including grid-connected inverters, transformers and battery energy storage systems (BESS).

Bulgaria now 'the most battery-intensive energy market in the world'

Bulgaria now has a world-leading amount of battery storage capacity relative to installed power capacity despite a period of political turnover, although those assets are now cannibalising the revenues that attracted investment in the first place. That's according to Ivaylo Stanchev, editor-in-chief of Bulgarian business publisher Capital. "Bulgaria currently has 5.4GW of operating battery storage. This is equal to 22.8% of the country's installed power capacity. In California, 16GW of operating in-state utility-scale batteries represent 14.9% of installed capacity," Stanchev told Energy-Storage.news.

Energy storage and smart grids take centre stage in India's renewables shift

Grids | India's electricity system is undergoing a fundamental transformation as the penetration of distributed renewable energy resources grows. Sarita Vijayvargiya and Shantanu Roy examine the role of battery storage and smart grids in the country's new energy landscape



Credit: Global Energy Alliance for People and Planet

As India's renewable energy landscape shifts from a large-scale, project-dominated model to one with a greater contribution from distributed renewable energy (DRE) resources, the country's electricity system is on the verge of a fundamental transformation. Rooftop solar, in particular, is expanding rapidly and already contributes nearly 20% of India's installed solar capacity as of August 2026. With this transition, consumers are increasingly becoming energy producers.

The growing penetration of DRE is also changing how electricity distribution networks operate in the country. These networks were conventionally designed to handle unidirectional, predictable power flow from the grid to consumers. However, now with higher DRE generation, primarily from rooftop solar, power flow is becoming bidirectional as well as varying throughout the day, creating numerous challenges.

To address these emerging challenges, new solar additions must be paired with a distributed, dynamic electricity system. Such a system would need greater network visibility, energy storage, improved forecasting and smarter distribution grid operation. As solar generation grows, midday declines in net loads and steeper evening ramps increase the need for flexible resources such as battery energy storage systems (BESS). Figure 1 illustrates this effect through the duck curve, which shows how increasing solar penetration can change the grid's net load profile [1].

Battery storage is taking on an increasingly significant role in India's energy system

This article first discusses the challenges of increasing renewable energy penetration and then explores how solar hosting capacity assessment, storage, digitalisation and AI-based approaches can help India develop flexible, intelligent distribution networks that can work in sync with rapidly increasing DRE capacity.

Why India's distribution grid is struggling to keep up with DRE

Growing DRE penetration transforms power flows and operating conditions of the distribution network, particularly at the low-voltage level. Conventional power distribution networks, which are largely designed for unidirectional and predictable power flows, are increasingly challenged by variable, dynamic loads. As DRE penetration increases, these limitations can create technical, operational, financial and planning challenges.

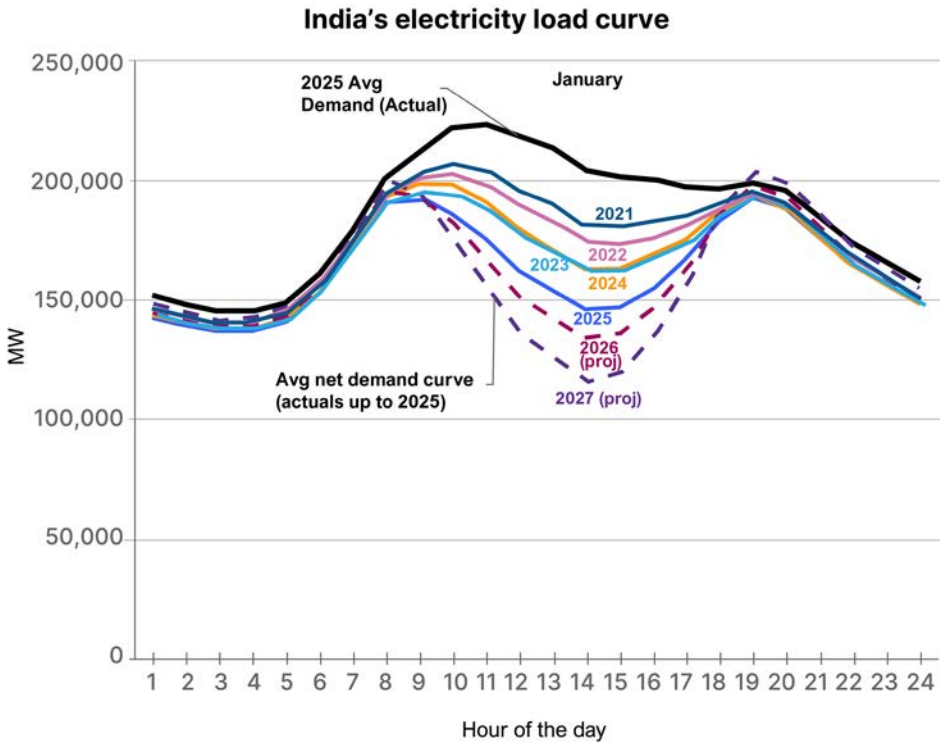
Technical stress on the network

During times of high solar generation and low local demand, the surplus generation is exported from the consumer/distribution transformer (DT) end to the upstream network, which can cause reverse power flows and potential voltage rises, leading to overvoltage conditions. At the same time, higher power flows through DTs and lines can increase loading and overload equipment; when multiple feeders connect to the grid, this can cause overall grid instability. Further, high renewable energy penetration can lead to technical losses and power quality problems. Changes in load and generation levels can also affect fault levels and protection coordination.

Variable generation, limited visibility

Limited network observability is a key limitation of conventional distribution networks. Comprehensive, real-time monitoring at the DT and consumer levels remains limited. According to the 'Report on Status of Metering in the Country (Feeders, Distribution Transformers & Consumers Metering)', as of 31 March 2025, 2,54,937 out of the 2,58,927 11kV feeders were metered, corresponding to 98.46% metering coverage. However, only 64,97,931 of the 1,53,60,382 DTs were metered, representing 42.30% coverage [2].

The substantially lower level of DT metering limits distribution companies' (DISCOMs') ability to accurately monitor local loading conditions, voltage profiles, power flows, and losses, particularly at the low-voltage end of the network. This limitation becomes increasingly significant as DRE penetration grows, where generation and consumption can vary considerably at the DT and consumer levels [2]. Limited observability also constrains effective loss management. Further, less real-time monitoring and automated control make it difficult to support the power quality and reliability of conventional networks, exacerbating voltage fluctuations, congestion and outages.



Source: India's deepening duck curves, Prof. Nikit Abhyankar

Figure 1. India's electricity demand duck curve [1]

Ageing infrastructure and limited grid flexibility

DRE output is often unpredictable and intermittent, making load-generation balancing and real-time grid operation more complex. Meanwhile, the growing adoption of rooftop solar, BESS, electric vehicles (EVs) and other distributed resources is creating more dynamic, bidirectional power flows. The shift from unidirectional to bidirectional power

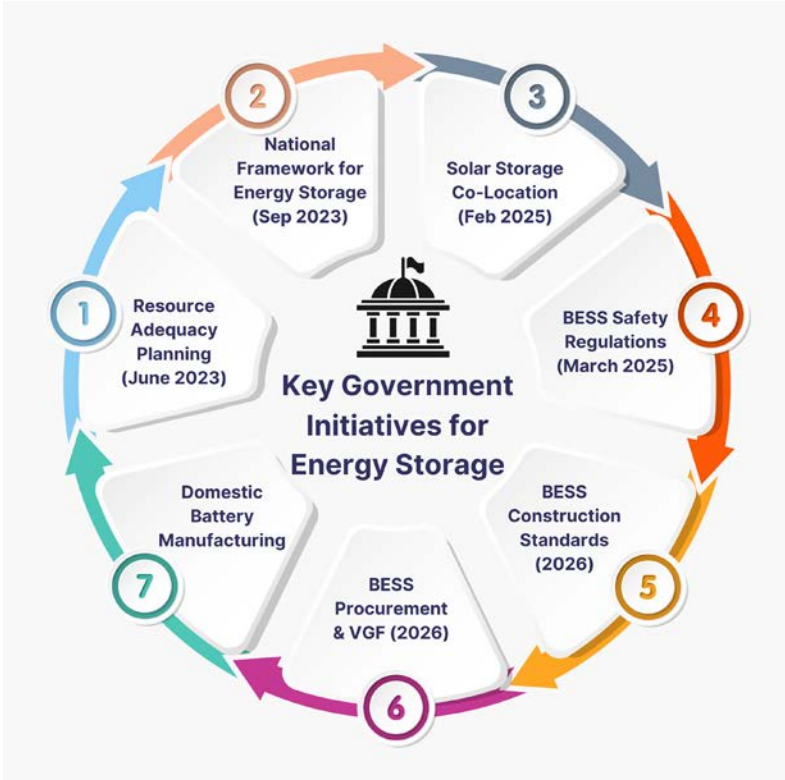


Figure 2. Key government initiatives for energy storage

flows reduces the effectiveness of traditional planning and operating methods for calculating hosting capacity and controlling DRE penetration. Conventional networks may lack the flexibility, automation and controllability required to accommodate these changes. Demand response, energy storage, advanced distribution management systems, smart-grid technologies and improved grid flexibility will therefore become increasingly important.

Costs, benefits and financial fragility

Increasing DRE penetration can also have financial implications for utilities and consumers. Grid reinforcement, infrastructure upgrades and modernisation will require additional investment, while changes in power flows can affect technical losses, utility revenue and energy procurement. At the same time, DRE can reduce energy expenses and create opportunities for new tariff designs, incentives and market mechanisms. Integrating DRE can also offer substantial environmental and social benefits, such as expanding access to renewable energy and reducing carbon emissions. It can improve energy equity, accessibility, resilience and local energy availability. Limited consumer awareness and understanding of BESS and other flexibility options may, however, restrict adoption and participation in demand response and distributed energy management. Finally, planners must also consider large-scale land use and local environmental factors [3, 4, 5].

Energy storage for renewable energy integration

As solar deployment and integration grow, grid flexibility challenges are increasing, particularly as declining solar generation coincides with rising evening demand. Between May and December 2025, India curtailed 2.3TWh of solar energy, about 18% of average monthly solar generation, Ember estimates [6]. Against this backdrop, India's Central Electricity Authority estimates that by 2032, the country will need 47.24GW of battery capacity to enable large-scale integration of reliable renewable energy [7]. The Energy Storage Obligation of DISCOMs is set at 4.0% up to 2029-30. This obligation shall be considered fulfilled only when at least 85% of the total energy stored in the ESS, on an annual basis, is procured from renewable energy sources [8].

These developments indicate storage's growing role as an integral component of India's new energy ecosystem. Government programmes are supporting both battery deployment and domestic manufacturing, while renewable energy tenders increasingly incorporate storage components (Figure 2).

To evaluate the need and potential role of BESS in distribution networks, it is crucial to consider the network constraints associated with increasing PV penetration. Feeder-level impacts of DRE can be addressed by assessing PV hosting capacity and locating BESS to absorb excess PV generation and operate the network safely.

Understanding PV hosting capacity

PV hosting capacity determines the maximum PV capacity each DT can accommodate while maintaining feeder operating limits. Each feeder has several consumers connected through the respective DTs. Interpreting the load consumption patterns of these DTs through load curves under different loading conditions (maximum/minimum/representative), based on load profile data, can clarify current feeder behaviour. In this context, minimum loading should be considered as the critical condition for PV hosting capacity analysis, as low feeder demand along with high PV generation can result in maximum reverse power flow and voltage rise. Furthermore, applying a load flow solution and optimisation approach at low loading clarifies PV hosting capacity by providing technical parameter details. The resulting PV hosting capacity provides the rationale for assessing higher PV penetration levels and serves as a reference for BESS integration.

BESS sizing and siting methodology

BESS sizing may involve various methods; some criteria are specific to the size, components and economics of a particular renewable energy system, while others apply well to systems of all sizes. For instance, one aspect applicable to all system sizes is the potential to curtail renewable generation when demand is low, such as in DRE systems and standalone hybrid energy storage systems. Voltage stability is also relevant to all systems, but only those connected to the distribution network use it for battery sizing. For DRE-integrated battery storage sizing, heuristic optimisation methods, including nature-inspired algorithms such as genetic algorithms, particle swarm optimisation, tabu search, bat algorithms and differential evolution, can satisfy technical and operational constraints [9].

BESS sizing and siting criteria are determined based on key inputs from load curves, PV hosting calculated in an earlier stage and feeder-level load characteristics and network operating conditions obtained from time-series load-flow analysis using power-system software. Once the PV hosting capacity is established, the storage size can be fixed based on identified network requirements, such as reverse power flow at the feeder level, minimum power loss and energy balance error.

Load-flow solutions at each candidate location, considering utility-level, DT-level and behind-the-meter perspectives, help identify the optimal location for BESS. Technical parameters within the range, such as minimum power losses, reduced reverse power flow, permissible voltage range and acceptable equipment loading, serve as references for potential storage locations.

However, if the aim is to analyse the maximum solar potential that can be deployed at the consumer level across the feeder, both BESS size and storage site can be treated as variables, and different BESS size/location combinations can be evaluated through time-series feeder-level load flow analysis. The evaluation study accounts for voltage rise, reverse power flow, power losses, transformer and equipment loading, and PV generation under different parametric sweeps. Comparing these factors helps assess the optimal BESS size and location needed to accommodate higher levels of solar deployment while maintaining reliable, stable feeder operation [9].

Case study: Rajasthan

The Center for Study of Science, Technology and Policy (CSTEP) carried out a similar exercise for a few feeders in Rajasthan, a state in north-western India, conducting feeder-level technical analysis for PV optimisation and BESS sizing and siting. Using a conservative maximum voltage limit of 1.02pu, along with line and transformer loading constraints, the optimisation identified approximately 3.135MW of PV accom-

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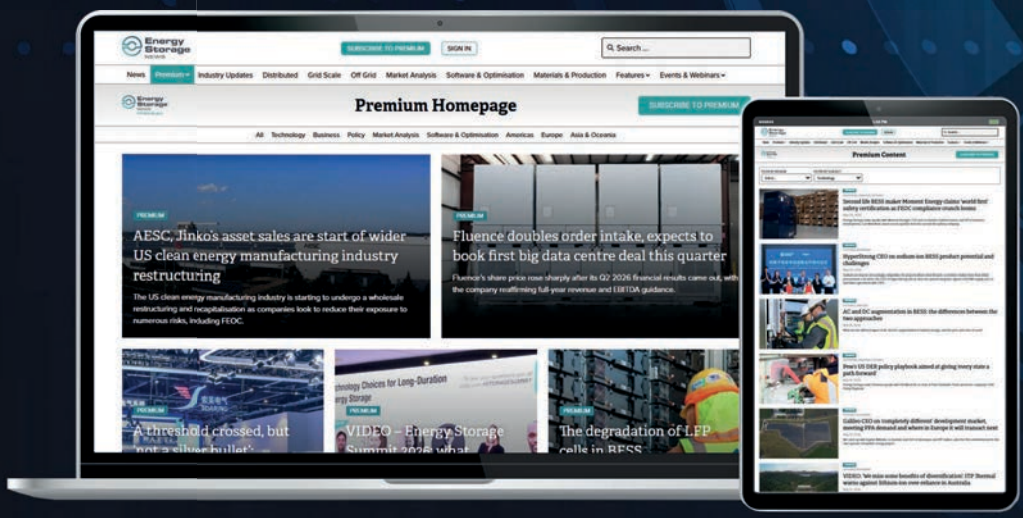
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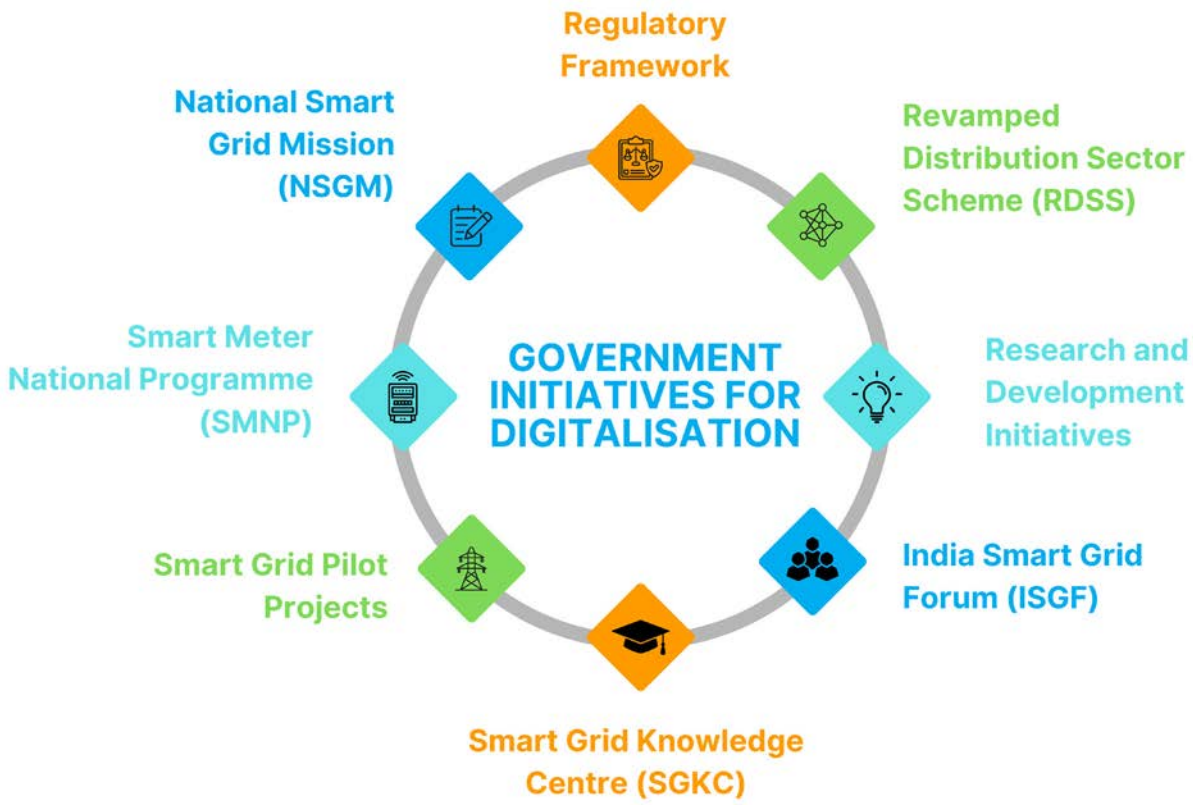


Figure 3. Government initiatives for digitalisation

modation across all 19 DTs on the feeder. The PV capacities were validated under minimum, representative and maximum loading conditions. A 1MW/4MWh BESS was considered with fixed power and energy ratings, while its location was optimised. Twenty candidate locations were evaluated, including the source bus and the low-voltage side of 19 DTs, using time-series load flow analysis. The optimal BESS location was identified based on minimum feeder energy losses while satisfying voltage, line loading and transformer loading constraints. The selected location was further evaluated for its impact on loss reduction, voltage improvement, reverse power flow mitigation and overall feeder performance.

Policy, regulatory and market challenges

Stable central and state policies are important for investor confidence, while uneven implementation and policy changes can reduce predictability. Strict technical and financial qualification criteria, timely power purchase agreement signing, firm offtake commitments, faster grid connectivity and adequate evacuation infrastructure can help reduce project delays and support timely renewable energy and storage deployment [1].

The financial stress faced by DISCOMs limits their ability to invest in the infrastructure upgrades needed for the clean energy transition. Tariff rationalisation and targeted financial assistance are important to strengthen DISCOM finances while enabling investment in distribution-grid modernisation [10]. Although India has expanded and modernised power generation and transmission capacity, distribution grid modernisation and digitalisation have lagged. Around 203.3 million smart meters have been sanctioned under the Revamped Distribution Sector Scheme; however, as of June 2026, only about 72.4 million had been installed nationwide under all schemes [11].

Emerging technologies, including BESS, remain subject to commercialisation, cost and supply-chain uncertainties. Geopolitical risks, foreign exchange volatility and limited access to credit can further affect deployment and investment decisions [5,12].

These policy, financial and market challenges highlight the need to strengthen not only investment and regulatory frameworks but also the operational capabilities of distribution networks. Storage can provide flexibility, but this flexibility cannot be effectively deployed or operated without adequate visibility, monitoring and automated control.

Digitalising the distribution grid

The growing need for real-time monitoring, visibility, automation and intelligent decision-making underscores the importance of smart distribution grids. Smart grids include advanced metering, real-time monitoring, automated network operation, demand response, DRE integration and data-driven decision-making; traditional grids lack these capabilities. As renewables, EVs and DRE scale up, the need for this advanced infrastructure is growing.

The government is supporting the digitalisation and modernisation of India's distribution sector through several initiatives (Figure 3) [13]. Demonstration projects across India have tested smart-grid technologies, operational models and integration approaches, while government-supported programmes promote R&D and demonstration of advanced smart-grid technologies.

The potential role of AI

Smart grids powered by an agentic AI solution can deliver scientifically sound solutions to intricate power-grid analyses within budget and in an easily understood way (Figure 4). Unlike traditional AI models that produce

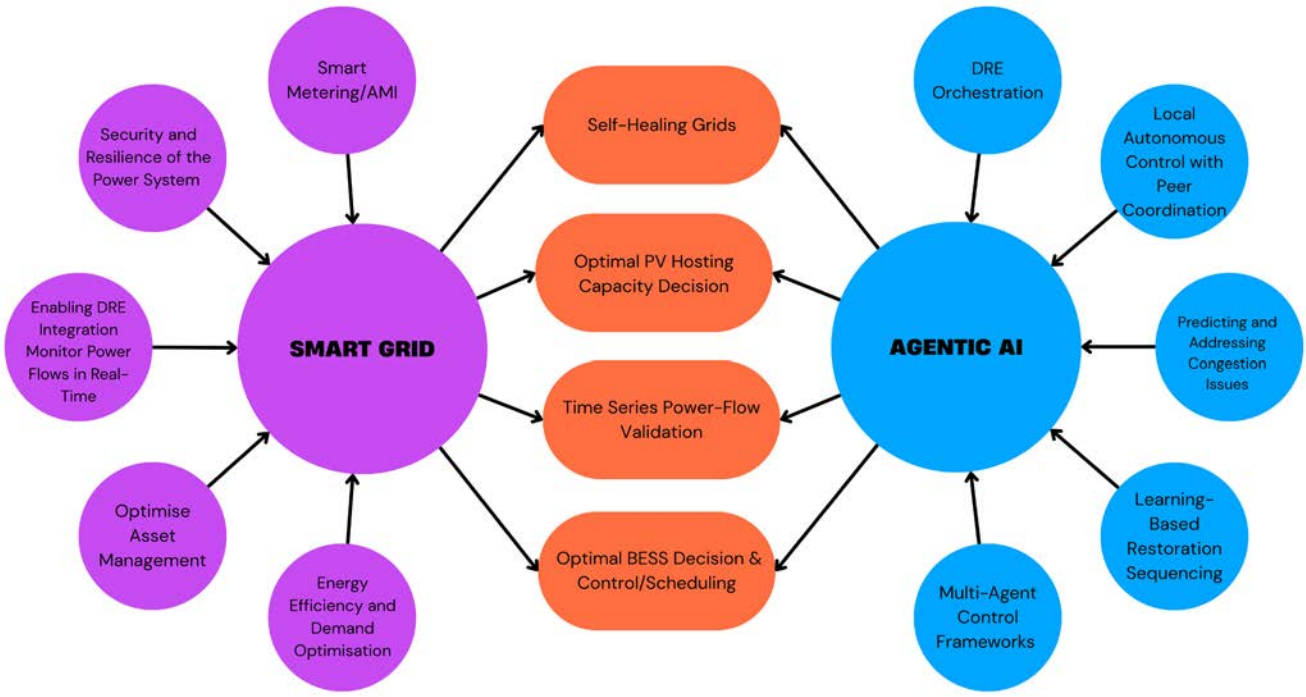


Figure 4. Agentic AI-enabled smart distribution grid: key features and capabilities

predictions or recommendations, agentic systems act. The agentic AI framework lets each DRE act as an agent with its own local objectives, enabling agents to negotiate supply-demand balances effectively. AI can optimise energy storage solutions, such as batteries, ensuring stored energy is used efficiently during times of low generation. In all, AI is changing the technical and operational landscape of distribution networks. Reinforcement-learning and multi-agent control frameworks can implement adaptive voltage regulation, load balancing and predictive congestion management. These approaches can outperform conventional deterministic optimisation under uncertainty. Providing physics-informed constraints in data-driven learning architectures can improve explainability and enable real-time decision-making in a distribution company [14].

Conclusion

The rapid proliferation of DRE capacity presents an opportunity to move towards a responsive, better-planned distribution system. This will require distribution planning to evolve from static assessments towards integrated, data-driven approaches that account for changing demand, generation and storage patterns. CSTEP's feeder-level assessments in Rajasthan illustrate the value of this approach by combining solar hosting analysis with storage sizing and siting to inform distribution-level planning.

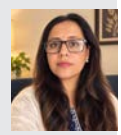
Digitalisation can provide the operational foundation for this transition by improving the availability and timeliness of network data. Smart metering, forecasting, real-time monitoring and advanced distributed energy management systems can work together to facilitate responsive and reliable grid operation, while AI-based approaches can further support the analysis of complex distribution-system data. ■

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The battery that lasts as long as the solar plant

Henning Rath, CEO of EnerVenue, on a lithium-free battery with space heritage that can cycle three times a day for 30 years, and where it fits beside lithium-ion



A solar plant is financed, built and insured to run for 30 years. The battery beside it is usually planned around an augmentation schedule, a replacement date and, in a growing number of counties, a public hearing about fire. That compromise is getting expensive.

From consumable to infrastructure

The scarcest asset in US power is now the grid connection. According to Lawrence Berkeley National Laboratory, more than 2,000GW of generation and storage, including 773GW of solar, is waiting in interconnection queues, and only 13% of the capacity that applied between 2000 and 2020 was ever built. A battery cannot shorten that queue; however it can keep a site's existing connection working into the evening and overnight, every day, for the life of the plant. Storage is no longer a consumable bolted onto a plant. It is infrastructure.

There is no perfect battery, only the right battery for the application. For two to four hours, lithium iron phosphate is hard to beat. When a site needs many hours, several cycles a day and decades of life, a different category comes in: lithium-free long-duration storage.

A battery made of steel and water

The Aqueous Metal Cell starts from the nickel-hydrogen chemistry NASA has relied on in space for decades. Stanford researchers replaced its platinum with low-cost materials and redesigned it for the grid. Each cell is a sealed steel vessel holding a water-based electrolyte. On charge, it splits water and stores the hydrogen; on discharge, it turns the hydrogen back into water.

Built to be cycled

The water-based chemistry does not produce the self-heating chain reaction that starts most battery fires, so there is zero risk of fire from thermal runaway. The cell passed UL 9540A, the fire-propagation test written for lithium-ion, with zero fire propagation. That changes the conversation with fire authorities, insurers and neighbors. It is rated for 30,000 cycles at full depth of discharge: three cycles a day for 30 years, with no augmentation. The same cell discharges over 45 minutes to 24 hours and operates from -20°C to 60°C.



The Aqueous Metal Cell, a sealed steel vessel with a water-based electrolyte

The economics follow the throughput. In EnerVenue's model of a 25MW/75 MWh system, run at a conservative two cycles a day for 30 years, the levelised cost of storage is US$80/MWh against US$108/MWh for vanadium flow, and the total cost of ownership is US$314 against US$500 per installed kWh. A battery that lasts the life of the project makes the case for financing it like the plant it serves.

The company opened its 250MWh high-volume production line in Changzhou, China, in September 2026 and plans 1GWh of annual capacity in 2027. Its first commercial order, 26 Energy Prism units totalling 11.5MWh, will store onsite solar at an oilfield in northern China; the first units ship in December. Customers include PowerSecure in the United States and Radiance Energy in Canada.

A 30-year solar plant needs a 30-year battery.

Author

Henning Rath is CEO of EnerVenue. He built Enpal's supply chain from China and founded Circ, the scooter company acquired by Bird.



The 250MWh high-volume production line in Changzhou, which opened in September 2026

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Data centre growth, energy storage opportunities and the ratepayer cost debate

Data centres | *Energy-Storage.news'* April Bonner looks back at a year in which the data centre debate took centre stage for society and the energy storage industry alike

Data centre development and the role that battery energy storage systems (BESS) can or should play in it have been widely discussed and consistently made industry headlines over the past year.

BESS developers seek to prove they can play an essential role in managing the unprecedented power fluctuations created by AI workloads at data centres, whilst also accelerating grid interconnection for facilities facing years-long delays.

Yet, as technology development enables rapid expansion, questions also arise about whether some of the world's wealthiest corporations should receive billions of dollars in tax breaks to build facilities that generate minimal employment and can strain local resources.

According to market research firm Wood Mackenzie's Q3 2026 'US Energy Storage Monitor' report, released in September, data centre buildout is uplifting the US storage outlook across all segments, noting that storage can provide needed capacity faster, more cheaply and more reliably than gas alone. As hyperscalers increasingly face grid-connection constraints, utility-scale storage will facilitate faster access to power for data centres, Wood Mackenzie said.

The accelerating deployment of AI data centres and hyperscale facilities makes BESS a critical component of grid integration, warranting closer examination of how these technologies intersect.

More than an accelerant

Early in the year, we heard from Jay Jayasuriya, former principal at Sendero Consulting, and Hugh Scott, chief technology officer at US system integrator FlexGen.

"I think it's the scale of the data centres that's going up and the fact that they are high-demand design facilities that make it very easy for people to say, 'Oh yes, data centres are messing up the grid. Data centres are causing prices to rise.' But they are more of a signal than anything," Jayasuriya said.



Credit: Energy Dome

Rendering of a forthcoming Energy Dome CO2 Battery project for Google in Arizona, US

He further notes that less attention was being given to how data centre developers could address grid constraints by constructing their own power infrastructure. Developers can combine energy storage with solar power and utilise off-peak electricity to charge batteries, which are then used during periods of high demand.

"That, along with other co-located generation facilities, represents an investment opportunity. Not only are the centres themselves involved, but investors see this as a way to enhance grid reliability and capitalise on market opportunities."

Complementing this viewpoint, FlexGen's Hugh Scott said BESS is the technology best able to handle the power fluctuations of AI training loads at data centres.

"Batteries are the only technology that can react at sub-cycle speed. Behind-the-meter (BTM) batteries absorb the fast transients, protect the grid from rapid swings and protect the data centre's own generators from operating outside their limits," Scott said.

As the year progressed, the industry saw large-scale announcements from tech giants such as Google and Meta using 'multi-day' long-duration energy storage (LDES) technologies from the likes of iron-air battery startup Form Energy and Noon Energy, which has a 'reversible electrofuels' battery.

Francesco Oppici, co-founder and CCO of carbon dioxide-based LDES company Energy Dome, which also announced large-scale data centre deals this year, said in April that the speed-to-power require-

"My concern is that all this technology right now is created by a handful of companies and a handful of people. The public really doesn't have any say in the process. Even our government doesn't have much to say about where the AI development is going"

ment of data centres is promoting US LDES commercialisation: "Unfortunately, I don't think at the moment, that there is structural revenue in place that can actually justify development outside of that firm capacity."

Raafe Khan, head of energy storage at owners' engineer and consultancy Camelot Energy Group told us in August his belief that data centres are an "accelerant" for BESS, but "not the foundation" for increased market interest.

"Even if data centres were to slow down for whatever reason, I don't think BESS would be as disproportionately impacted as, let's say, gas generation," Khan said at the time.

Khan contended that the energy storage sector has fundamentally misconstrued the value proposition of behind-the-meter (BTM) batteries compared to grid-connected systems.

For captive installations, the primary benefits centre on accelerated interconnection timelines, operational flexibility, and backup power capabilities—with the true economic driver being avoided delays rather than energy arbitrage economics.

Wholesale market batteries, by contrast, operate under distinctly different constraints. "Your biggest counterparty risk is ISO settlement," Khan observed. "Your duration is going to be more optimised to the market, whereas in a captive situation, you could do more than four hours, even more than eight hours, if you're going to be an islanded private power network."

PJM and 'Data Centre Alley'

Nearly synonymous with data centre development in the US is the PJM Interconnection, home to Virginia's 'Data Centre Alley,' the world's largest concentration of data centres.

PJM, the US' biggest regional transmission organisation (RTO), faces mounting challenges from surging electricity demand forecasts and a capacity market structure that many participants now consider ill-suited to current grid realities.

In January, the Trump administration joined forces with governors from both parties and US energy secretary Chris Wright to call for a temporary restructuring of PJM's market framework—aiming to bolster grid reliability and lower consumer electricity costs through the development of over US$15 billion in baseload generation capacity.

PJM's decision, issued later that month, addressed some of these concerns. Among its provisions, the grid operator announced it would launch a 'Reliability Backstop Procurement' (RBP) mechanism.'

Energy-Storage.news discussed PJM's policy response with two experts in May: wholesale electricity policy specialist Andrew Levitt and Dr Long Lam, managing energy associate at the Brattle Group.

PJM's 'Powering Reliability Through Market Design' document presented three divergent reform scenarios, each reshaping how the nation's largest regional grid would secure generation capacity, distribute costs among participants, and accommodate technologies like BESS.

The core tension centres on the capacity market's uniform price-setting mechanism—historically viewed as essential to competitive electricity markets—which now confronts political constraints that have forced prices below the threshold needed to finance new power plants.

During the summer, PJM submitted a two-part plan to the Federal Energy Regulatory Commission (FERC) on 31 July and 7 August proposing a major overhaul of how it procures power capacity. The proposed plan included a one-time RBP for new capacity from 30 September to 21 October.

FERC did broadly accept PJM's RBP framework but, crucially, delayed its effective date by five months. The key reason for the delay was that PJM did not clearly show how it would require data centres to pay for their own capacity.

"FERC's decision leaves the public exposed to rolling blackouts and higher bills caused by data centre electricity demand. In denying PJM's proposal, FERC disregarded the White House's Ratepayer Protection Pledge, where major tech companies promised to pay for the infrastructure their data centres need," Claire Lang-Ree, clean energy advocate at the Natural Resources Defense Council (NRDC) says.

She continues, "Instead of requiring data centres to bring their own new capacity, FERC's decision will force the public to continue paying for data centre's power supply. FERC also ordered PJM to continue providing uninterrupted service to new data centres beyond what the grid can handle, further degrading reliability."

While PJM's capacity market struggles offer one vivid example, they point to a systemic issue—data centres are driving up costs and consuming grid resources at an unprecedented scale across multiple regions.

Impact on ratepayers

Good Jobs First, a research organisation focused on corporate subsidies and economic development, noted in an April report that "Fourteen states and scores of localities across the US fail to disclose how much revenue they lose to data centre tax abatement programmes."

Three states had disclosed losing US$1 billion or more per year. This is important because, as the progressive US think tank Centre on Budget and Policy Priorities noted in August, "Forty states provide some sort of subsidy for data centres. The most common type is a sales tax exemption for the materials and technology purchased, either initially or on an ongoing basis. Some states also give data centres special rates for utilities, breaks for real property taxes, breaks for personal property taxes on equipment, or credits for corporate income taxes."

The examination of the loss is crucial when considering the frequency at which data centre developers claim their projects will increase local tax revenue.

Some would argue, however, that data centres are imperfect vehicles for BESS and other renewable technology innovation.

Kasia Tarczynska from Good Jobs First takes issue with the argument that data centres will accelerate the commercialisation of LDES or non-lithium BESS technologies:

"My concern is that all this technology right now is created by a handful of companies and a handful of people. The public really doesn't have any say in the process. Even our government doesn't

have much to say about where the AI development is going."

Tarczynska challenges the premise that tax incentives are necessary at all, noting that data centres represent investments by some of the world's wealthiest corporations. "We are talking about a few very rich and powerful corporations. They are projecting to spend hundreds of billions of dollars, not millions, in investment. With that huge amount of investment, I'm sure they can spend a little bit of money to pay crucial taxes."

She points out that property taxes typically represent only 2% of project investment costs—"a drop in a bucket" for major technology companies, but crucial revenue for local communities.

"The purpose is to help bring a project to a community that would not happen without the tax break," Tarczynska says. "With data centres, we just don't see these dynamics. Data centres have to be built so that big tech companies can run their business, which is to create AI language models. The market itself incentivises companies to build more data centres, so there's really no need for public financial support to encourage that growth."

Tarczynska says the billions of dollars in investment frequently cited by data centre developers are private expenditures and not public benefits. "These billions of dollars are spent to create a private investment. The government only gets a share through taxes. If a local government provides 90% of property tax abatements, they're basically giving up 90% of tax revenue."

There are also concerns for potential healthcare costs associated with air pollution from backup generators: "There's a cost through increased healthcare expenses to treat people because there will be more asthma, there will be more cancer. Academics have shown and put a number to the healthcare cost of data centre pollution."

"Property taxes are major revenue for schools in this country," Tarczynska says. "If we are abating property taxes for companies, it means the local school district most likely is not going to get that money. Property tax breaks are directly attached to lower revenues for school districts."

Perhaps most provocatively, Tarczynska notes the contradiction inherent in subsidising companies whose stated goal includes workforce reduction: "Big tech company CEOs have said that one of the goals of AI is to replace human workers with AI. So, are we subsidising these companies to destroy whole sectors? Journalists, researchers, other professions? Are we subsidising the destruction of jobs?"

She frames data centres as "just the physical dimension of the larger problem of monopoly and corporate power," questioning whether decisions about technological infrastructure that will reshape society should rest with "a handful of white men" rather than through broader democratic processes.

The Trump administration has worked to accelerate the deployment of data centres. Responding to the criticism of their resource use and costs to ratepayers, it announced the Ratepayer Protection Pledge in March.

BESS and 'Bring Your Own Capacity'

The Ratepayer Protection Pledge itself was a largely symbolic attempt to assuage public concerns. Voluntarily signed by Amazon, Google, Meta, Microsoft, OpenAI, Oracle and xAI, the unenforceable pledge involves committing to bringing, building or buying your own capacity ('BYOC'), and covering all costs of upgrading power delivery infrastructure for data centres.

Notably, large tech companies have largely been committed to the BYOC model prior to the announcement of the pledge and following it. As noted, many data centres are also making use of BESS.

In July, *Energy-Storage.news* wrote about several partnerships between AI data centre and BESS developers. These involved Siemens developing a reference architecture purpose-built for Nvidia data centres in collaboration with Fluence, which will supply the BESS for the data centres; and Prevalon partnering with Emerson to use gas turbines to support hyperscalers and data centres, among others.

However, BYOC is not a perfect mechanism. For instance, data centre developer DataOne began operating a data centre in Vineland, New Jersey, supporting Microsoft. Part of the plan for the facility was to use an existing natural gas pipeline for Bloom Energy fuel cells, turning natural gas into electricity and generating its own energy to prevent an increase in ratepayer electric bills.

In September, the New Jersey Department of Environmental Protection issued DataOne a US$1.07 million fine after finding it was operating at least 45 gas-powered generators without a permit.

This is indicative of a larger issue, and according to sustainability media platform Trellis Group, Amazon, Google and Microsoft all reported double-digit emissions increases in their 2025 environmental sustainability updates.

Reported emissions from power usage surged by over one-third at Amazon and Google, whilst Microsoft recorded an increase exceeding 20%. Google has said that "the shift to clean energy is hitting major bottlenecks".

Earlier this year, the Kansas Health Institute released a study stating that 56% of the electricity generated for the purpose of powering data centres comes from fossil fuels, while 22% comes from renewables, and 21% from nuclear.

BYOC strategies frequently combine BESS with on-site gas generation, diesel backup, or co-located solar. Hugh Scott of FlexGen's point that batteries excel at absorbing sub-cycle transients and protecting generators from operating outside their limits positions BESS as a supporting, protective technology within these hybrid builds.

If data centres lean more heavily on gas or diesel generation as the backbone of BYOC capacity, with BESS relegated to a smaller role managing power quality, the technology captures a narrower economic opportunity within the model than current developer announcements suggest.

This suggests BYOC may prove to be a transitional mechanism tied to a specific set of interconnection bottlenecks and speculative demand conditions, rather than a structural pillar for BESS growth, reinforcing Khan's broader framing that data centres remain an "accelerant" for storage rather than its "foundation".

Further, according to *Politico* in October, more than 150 data centres have been delayed or abandoned, with cancelled investments exceeding US$260 billion.

BYOC's main appeal is bypassing interconnection queues, and not storage economics. Much of the announced data centre pipeline may not materialise at scale, risking stranded storage sized to unrealised load.

For BESS developers, this could mean that the sector's near-term growth may remain tightly coupled to a volatile and ideologically contested data centre pipeline, where speed-to-power value could evaporate as quickly as it emerged, should interconnection reform, state-level cost allocation or a downturn in hyperscaler capex investment take hold. ■

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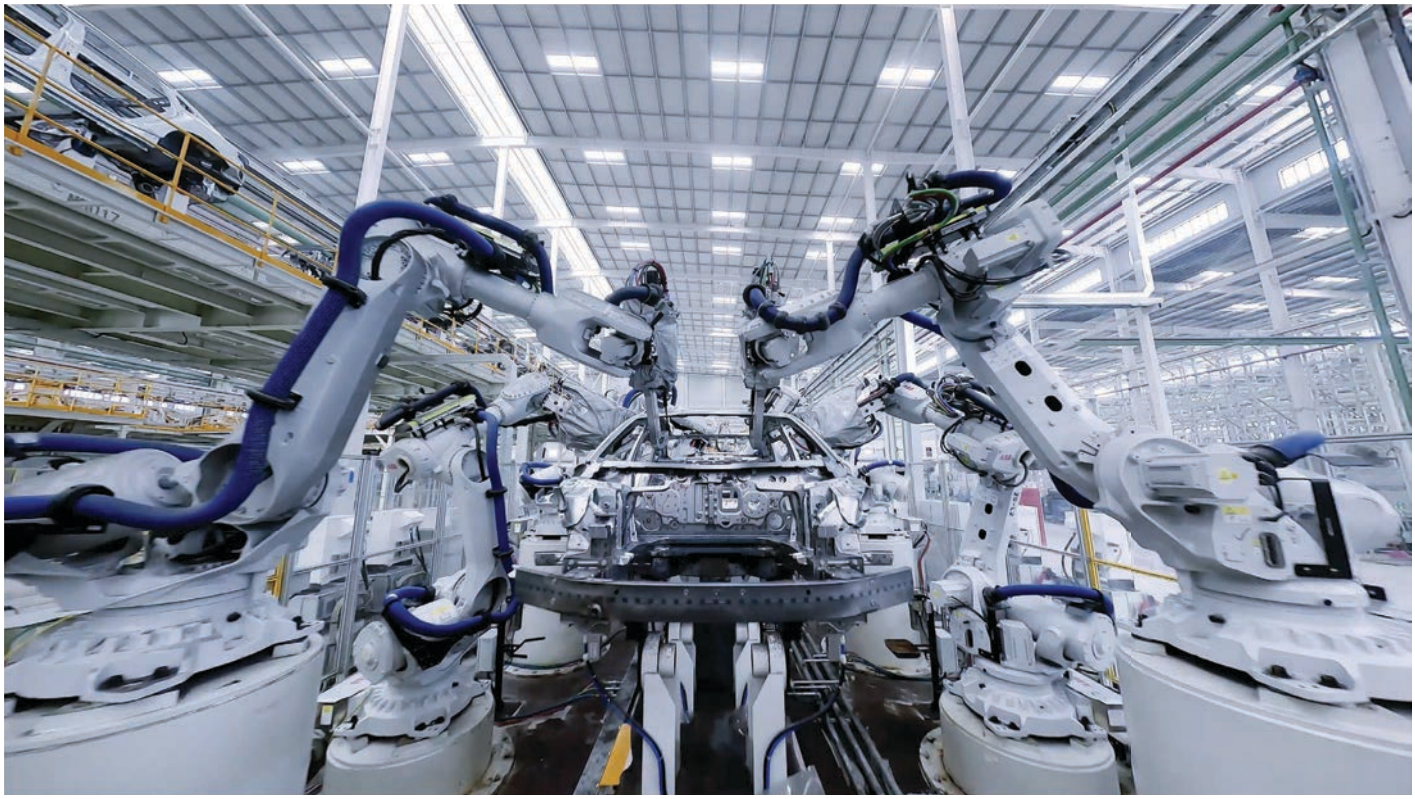
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Who's gaining geopolitical advantage in the energy transition?

Geopolitics | Energy transition expert Chris Nelder offers his take on the central premise dividing the globe along 'petrostate' and 'electrostate' lines, analysing news stories from *PV Tech*, *Energy-Storage.news* and *EV Infrastructure News* in 2026



Credit: BYD

A stute observers of the energy transition now think of countries as belonging to one of two groups: the 'petrostates' and the 'electrostates.' Historically, 'petrostates' were considered to be those whose economy and government are heavily dependent on revenues from the production and export of oil and/or natural gas. Now, the term is often interpreted more broadly to mean countries primarily committed to a fossil-fuelled energy regime. Petrostates often also rely on nuclear power to generate electricity, with some governments continuing to pursue and subsidise it even though it is now the most expensive way to produce electricity.

By contrast, 'electrostates' are those primarily pursuing an energy strategy built around electricity, where it's implied that the electricity is primarily clean and produced from renewable sources.

China has emerged as the clear leader in electrostates globally due to its dominant position in the manufacture, export and domestic use of solar, wind, batteries and electric vehicles, among other things. OPEC+ countries are the ones most often thought of as petrostates, although the US has started to look like one as well under President Trump's leadership.

Largely thanks to the manifold effects of the war on Iran, this year has seen significant shifts across this spectrum, with many developing countries, long expected to pursue fossil-fuelled pathways out of energy poverty, rapidly adopting electric solutions and renewables instead.

A BYD production plant in China. China's leadership in the energy transition is enhancing its geopolital heft

Their motivations are straightforward: it's far better and cheaper to be able to provide one's own energy from domestic clean sources whose supply is assured than to remain dependent on supplies of imported fossil fuels whose supply can be disrupted. That's been especially true this year, as the partial closure of the Strait of Hormuz sharply curbed exports of oil and natural gas from the Persian Gulf and caused prices to soar. The risk of losing access to crucial energy supplies alone would be reason enough to transition to reliable domestic sources, but the cost of imported fuels has radically accelerated those transitions across the world this year.

What's also becoming clear is that strategically transitioning to domestic

renewables and electrification also confers significant geopolitical advantage.

China

China is clearly gaining power—both market power and geopolitical clout—for its leadership in the energy transition. As an exporter, it's capitalising handsomely on the solar, wind and battery storage equipment it manufactures.

While its might as the world's top solar provider is well known, the extent to which it is using that might to form geopolitical alliances is perhaps underappreciated. Solar module imports from China to Africa grew by 53% year-on-year in the 12 months to June 2026, according to energy think tank Ember. And 19 countries, including the DRC, Zimbabwe and Egypt, are on track to see solar installations grow by more than 100% this year.

Battery energy storage systems (BESS) have also become a booming market for Chinese exports. China booked nearly 300GWh of orders for its storage solutions in H1 2026, an 83% increase year-over-year, according to CNESA DataLink.

China is also increasingly gaining geopolitical and economic leverage through its production and use of electric vehicles (EVs). According to the IEA's 'Global EV Outlook 2026', Chinese automakers supplied 60% of global electric car sales in 2025, but in the first quarter of 2026, China's electric car exports more than doubled over the same period in 2025. China also has the world's largest fleet of EVs, with battery electric vehicles (BEVs) and plug-in hybrid EVs (PHEVs) combined outselling internal combustion engine (ICE) vehicles for more than two years now.

Similar dynamics are now evident in electric trucks as well. More than nine out of every ten electric medium- and heavy-duty trucks sold globally in 2025 were sold in China. Electric models now account for more than a quarter of the heavy-truck market there, and sales of electric trucks have doubled for the past two years in a row. Based on current policies, the IEA reckons, electric trucks are set to take at least a 20% share of global truck sales in 2035, led by China, where they are expected to take a 60% share. Chinese electric truck exports have more than doubled since the war started, with shipments to South Asia up more than fivefold and to Southeast Asia nearly tripling.

A massive and sustained programme of electric train construction that added over 3,100 km of new railway in 2025 alone, the electrification of cars and trucks and the capacity to fall back on its own strategic petroleum reserve have enabled China to cut its oil imports by 41% year-over-year in June, and to cut its overall oil consumption in Q2 by 9%, according to Carbon Brief. Arguably, China single-handedly stabilised the global oil market and avoided widely expected and severe outcomes of the war. Instead, the rest of the world merely experienced elevated prices for oil and gas.



Credit: Ola Electric

Battery production at Ola Electric, an Indian EV manufacturer which recently entered the BESS market

The net result is that China—the world's largest oil importer—has displaced around 1,000 barrels of oil per day (mb/d) of oil demand with electric cars in 2025. That should grow to 2.7 mb/d annually by 2030, according to the IEA. Its electric truck fleet will displace another 141 million barrels of oil (roughly 0.4 mb/d) this year, more than 3% of China's total and equal to all its imports from Kuwait, according to the Centre for Research on Energy and Clean Air (CREA). Electric vehicles alone accounted for about one-third of the decline in its oil demand. And there is a positive climate impact: China's emissions fell for the first time this year because it used less oil, and not because it used less coal.

China is clearly using its energy might and its ability to reduce its oil demand in the face of a global oil crisis as both a defensive and offensive weapon. It avoided economic damage from sharply higher prices for oil and gas even as it extended its reach as an exporter of oil-displacing technologies globally—as an exporter of goods manufactured in China and as a major partner in overseas manufacturing, operations, technical assistance and project delivery. That's geopolitical power, and with every passing year, China's grows.

South Korea

South Korea also intends to use electrotech for geopolitical advantage.

The government announced a KRW1,000 trillion (US$747 billion) energy transition and decarbonisation strategy called the K-GX, or Korea-Green Transformation plan. Through 2035, it aims to:

- build at least 100GW of renewable energy capacity
- support industries including green steel, batteries, solar power, wind energy, hydrogen and small modular reactors
- push electric and hydrogen-powered vehicles to at least a 70% share of new vehicle sales
- accelerate decarbonisation in its five highest-emitting industries—steel, petrochemicals, refining, cement, and semiconductors and displays
- lead the global green steel market by becoming the first country to mass-produce hydrogen-reduced steel
- commercialise tandem solar cells by 2028
- build domestic supply chains for key clean-energy technologies.

That's a full-board industrial policy, specifically designed to make South Korea an electrotech powerhouse while substantially eliminating its dependence on imported fossil fuels.

India

India has put domestic solar manufacturing at the centre of its industrial strategy.

The South Asian nation has been deploying solar at a record pace, with 34GWdc of solar capacity deployed in the first half of 2026, 38% above H1 2025 levels. More than 50GWdc is forecast to be deployed in 2026.

But it's not just deploying Chinese-made solar cells anymore. Starting 1 June 2026, a broad set of projects involving

government programmes, projects, assistance and transactions must meet domestic content and approved-supplier requirements set out in the Approved List of Models and Manufacturers-II (ALMM-II). Those projects can no longer use modules made in India with imported Chinese solar cells; under ALMM-II, the cells themselves must also be made in India.

As of mid-2026, India had about 36GW of annual solar-cell manufacturing capacity, but capacity is expanding rapidly. According to company-level estimates compiled by Nuvama Research, solar cell capacity additions will be 130-150GW by 2028-29. That expansion is intended to help close the gap between India's domestic manufacturing capability and the capacity required under ALMM-II.

India isn't just using its economic muscle to build up a domestic solar manufacturing industry; it's also investing abroad. Indian energy company Nava Limited has commissioned a 100MW solar PV project in Zambia through its step-down subsidiary Maamba Solar Energy Limited (MSEL). CEO Ashwin Devineni said the project "reinforces our vision of building a diversified, future-ready energy portfolio across geographies".

Indian module manufacturer and EPC Navitas Solar has secured a US$20 million contract for a 54MW utility-scale solar project in Zambia's Serenje Province. The independent power producer (IPP) arm of India's INOXGFL Group, through a joint venture with RJ Corp, is also expanding into African renewable energy markets with its acquisition of SkyPower Services MENA, and is targeting 570MW in its initial phase and 2.5GW of operational renewable capacity in Africa by FY29, across markets including the Democratic Republic of the Congo (DRC), Zambia and Zimbabwe.

India is even manufacturing solar modules in partnership with the US perovskite technology company Caelux, with 19GW of contracted volume in development.

High anti-dumping (AD) and countervailing duty (CVD) rates imposed by the US on crystalline silicon PV cells imported from India, Indonesia and Laos, with combined rates as high as 249% for Indian manufacturers, will largely close off the US market to those manufacturers. However, India's Ministry of New and Renewable Energy (MNRE) is working with the Export-Import Bank of India (Exim Bank) to help solar manufacturers diversify away from the United States and develop markets in Europe, Africa and Latin America.

That increased supply competition outside the US is likely to put downward pressure on global solar prices while fostering a more robust global supply chain and making the PV industry more competitive than it would have been had it remained dependent on the US market.

India is also leaning hard into EVs. Domestic manufacturing capabilities, declining battery costs and government subsidies are expanding India's EV fleet beyond the two- and three-wheelers that have been the primary markets so far to all vehicle categories, from scooters to buses.

Estimates for India's EV market vary quite widely. For example, IMARC estimates that the EV market will grow at a CAGR of 48%, ballooning from US$1.5 billion in 2025 to US$50.5 billion by 2034. Meanwhile, the Indian government's India Brand Equity Foundation (IBEF) put the 2025 market value closer to US$3.7 billion, forecasting a rise to just over US$191 billion by 2034.

For the Indian EV charging infrastructure market, most analysts forecast a compound annual growth rate (CAGR) of 25-30% between now and 2034.

Under the Prime Minister's Electric Drive Revolution in Innovative Vehicle Enhancement, known as the PM E-DRIVE scheme, subsidies are on offer for all vehicle classes. The current budget is designed to subsidise 72,000+ charging stations and 22,000+ four-wheelers before the scheme concludes in 2028.

On the whole, India is clearly aiming to use an industrial policy built on energy transition solutions to sharply cut its dependence on imported fossil fuels, expand its market power as an EV and solar PV manufacturer and project its geopolitical influence as it rapidly transforms into a globally significant electrotech economy.

Southeast Asia

Across Southeast Asia, numerous projects have emerged this year as countries seek to replace imported LNG with domestic renewables.

For the past two years, the Philippines has turned to rooftop solar to offset high electricity prices, while halting at least three LNG-related projects.

The Philippines will also be the site of the world's largest combined solar-plus-storage facility when it reaches full scale. With a current capacity of 1.373GWac of solar PV and 825MW/3.3GWh of BESS, the MTerra Solar plant has already begun generation. When complete, it's expected to have 3.5GWp of solar PV capacity and 4.5GWh of BESS capacity.

In Malaysia, 400MW/1,600MWh of BESS projects are on offer to support Malaysia's National Energy Transition Roadmap (NETRA), which targets 70% installed renewable energy capacity and net-zero emissions by 2050.

Malaysia's first-ever grid-scale BESS was only deployed in late 2025 in Sabah, one of two Malaysian states on the island of Borneo. The island has a much smaller grid and fewer dispatchable natural gas resources than Peninsular Malaysia, making the need for storage to stabilise the electricity network and ensure continuity of supply more acute.

Malaysian state-owned electricity company Tenaga Nasional Berhad (TNB) inaugurated its first BESS project in May, the 100MW/400MWh Santong BESS. Equipped with grid-forming (GFM) inverters, the project aims to strengthen and increase the stability of electricity supply on the East Coast of Peninsular Malaysia. In July, the Malaysian government launched a solicitation for 2.5GW of solar PV co-located with 1.25GW of battery storage.

This tiny sample of projects is indicative of an enormous pipeline of solar and battery projects across Asia. And it explains why, as David Fickling observed for Bloomberg, "Emerging Asia is the future of the LNG market—one that never seems to show up in present-day reality." For more than a decade, LNG producers have eyed the region as their best growth prospects, seeing expanding demand in Thailand, Bangladesh, the Philippines and Vietnam. But that demand really hasn't materialised. Excluding China, gas power demand in Asia has barely increased in 15 years. Instead, those countries are turning to renewables.

Asia now generates more power from solar than it does from gas, according to analysis by Carbon Brief. Solar power in nations such as China, India and Pakistan has increased nearly fourfold since 2020.

Thailand's latest power market plan, published in September, calls for increasing the share of renewable energy on its grid from 20% now to 50% within the next decade, then rising as high as 89% around 2050. Energy minister Akanat Promphan's rationale for the plan was

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Credit: Meralco TerraSolar

President Ferdinand Marcos Jr (centre) at the inauguration of the Philippines' MTerra Solar project's first phase

blunt: to reduce reliance on "expensive and volatile spot LNG imports".

In Bangladesh, where dependence on LNG has been an enormous economic burden this year, the current plan is to increase solar power generation and domestic gas exploration. In September, Prime Minister Tarique Rahman told parliament, "We will no longer be consumers of imported energy. We will be solar power producers."

The Philippines is increasingly looking at gas-fired power plants merely as firming resources to backstop renewables rather than as primary generators. Vietnam is likewise backing away from long-term power purchasing contracts with developers of LNG-fired plants. Wood Mackenzie estimates that only 14.9GW of Southeast Asia's planned 53GW of gas-fired power projects will come online by 2030, with 25.7GW of projects in Vietnam alone unlikely to start by then.

According to Ember data, gas-fired power output has declined in Bangladesh, Pakistan and India in the last five years as coal and renewables expanded. Across the region, the outlook for gas is fading amid gas price uncertainty and is being replaced by visions of renewably powered countries, according to Rystad Energy. The firm has cut its long-term Asia LNG demand forecasts for 2040 and beyond, as countries including Vietnam and the Philippines have not secured sufficient LNG supply deals and infrastructure.

Europe

Trade association SolarPower Europe found the continent has saved more than €30 billion (US$34.74 billion) in gas imports in the six months after the war in Iran began by turning to solar. And solar proved more reliable over a scorching summer than hydropower as reservoir levels fell, or nuclear power as the temperature of water needed for cooling rose above acceptable limits.

"Solar has been delivering huge financial benefits for Europe since the latest fossil fuel crisis in the Middle East began," said SolarPower Europe CEO Walburga Hemetsberger. "The Iran war deepened the turmoil in energy markets generated by Russia's invasion of Ukraine. A dependency on the flow of oil and gas is clearly a risky energy strategy."

Ember's figures show that, in June, solar PV accounted for 25% of the EU's electricity generation, which exceeded that of both nuclear (21%) and hydropower (12%). This was the second time on record that solar output exceeded that of nuclear power, but that's likely to remain the case in the future as global warming continues to imperil water supplies and solar capacity continues to grow.

EVs are also saving Europeans a lot of money. Last year, battery electric cars across the EU were 33% cheaper to operate than gasoline-powered alternatives, according to the International Council on Clean Transportation (ICCT). But this year, the oil crisis brought on by the Iran war raised the energy costs of ICE cars by 12% to 36%, while the cost of operating an EV remained largely flat, so the gap between ICE and EV operating costs continued to widen. There is also a widening gap in new car sticker prices, with the price of an EV in Germany falling by 18% from 2020 to 2025, while the cost of an ICE increased by 2%. Even long-haul electric trucks in Germany are already 11% cheaper to own than their diesel counterparts.

That would help to explain why hybrid-electric cars now dominate the European market, at 37%, while the market share of ICE cars fell to 29% (down from 38% the year before) and BEV sales exceeded 20% in the first eight months of 2026.

Both purchase price and operating cost gaps are virtually certain to continue to expand, as oil prices remain elevated and continue to rise. Meanwhile, battery costs continue to fall.

Europe is clearly on course to continue its clean electrification strategy, with the German cabinet approving a national roadmap to phase out coal, oil and gas by 2045. That makes Germany the third country, after France and the Netherlands, to adopt such a roadmap under an international initiative to move away from fossil fuels.

Nuclear power is also beginning to be abandoned in favour of renewables, with Hungary pivoting to wind after the summer's drought forced its main nuclear plant to the brink of a shutdown.

Across the world, countries migrating toward the electrostate model are cutting their costs, increasing the reliability of their grids and discovering the benefits of mutual investment and cooperation in an evolving global market for clean energy and electrified solutions.

United States

Meanwhile, in the US, Trump's order to ban inverters, transformers and batteries from 24 countries, including China, is driving up prices for solar and various grid components. The ban on inverters is making some renewable projects uneconomic and reducing their productivity.

Trump's tariffs on solar PV modules have increased their cost by more than 40%, putting them well above their cost in Europe. In December, Section 232 tariffs will increase costs by another 15% while hard limits on imports will restrict them to levels below their historic averages.

Not only will these moves slow the pace of renewable energy deployments in the US, they are also hurting its manufacturers. US-headquartered energy storage technology, services and software provider Fluence was forced to write down its expected 2026 revenue by US$600 million after delays in executing its investments in US manufacturing and supply chains.

And that's without even beginning to account for the loss of major wind and solar farms that were cancelled by

the Trump administration, the near-total abandonment of the EV market by major US auto manufacturers and the enormous costs forced onto the public by the administration's orders to keep money-losing coal- and gas-fired power plants operational instead of allowing them to retire as planned.

As an exporter of electrotech globally, the US has transitioned from being one of its original inventors to being a largely insignificant player, abandoning the field to developing countries eager to seize its economic and security benefits.

If the president intended to diminish America's geopolitical influence in the world and make it uncompetitive with the rising electrostates, what he has done would be a good way to go about it.

A complex reality with a simple conclusion

One thing that is clear from history is that the gains made by the electrostates and the losses made by petrostates will be permanent. Once a nation switches from ICE vehicles to EVs, or from fossil-fuelled grid power to solar, or from oil- or gas-burning boilers to electric heat pumps, those transitions are extremely unlikely to be reversed.

New analysis by Ember estimates electric cars in oil-importing countries displaced 200 million barrels of crude, worth around US$20 billion, in the six months after the Hormuz crisis began. EV fleets are now delivering more than reduced carbon emissions; they're providing energy security and significant cost savings. Ember reckons that China saved about US$14 billion; EU member states US$3.1 billion; the UK about US$790 million; and ASEAN about US$560 million.

BEV sales grew to an 18% share of all new-car sales, while PHEV sales fell 12% and ICE car sales fell 6%. Outside the US and China, BEV sales grew about 45%, and 49 of 56 tracked countries set record BEV shares. The US went the other way, with the share of BEVs falling to 6%, putting it below 15 other countries, including Brazil, India and Malaysia.

A broad global theme has emerged this year, especially since the onset of the Iran war: President Trump's efforts to support the oil and gas industry and stymie renewable energy and EVs in the US have ultimately backfired, and accelerated the energy transition by turning global markets away from unreliable and expensive supplies of oil and gas and toward more affordable and reliable domestic renewables and electrified applications. Ultimately, it amounts to a transfer of geopolitical advantage away from the US and other petrostates, and toward electrostates. ■

Author

Chris Nelder is the publisher of the Transition Times energy transition newsletter and podcast. Chris has been writing about and working in the energy transition for more than 20 years. He was creator and host of the Energy Transition Show podcast, and a full-time peripatetic podcaster. Prior to taking the podcast on the road full-time, he headed the EV Grid Integration team at RMI. He is the author of two books on energy and investing, as well as more than 200 articles on energy in publications such as *Nature*, *Scientific American*, *Slate*, *The Atlantic*, *Quartz*, and the *Financial Times*.

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